Statement of Basis
for
Draft Amended Federal “Prevention of Significant Deterioration” Permit

Russell City Energy Center

Bay Area Air Quality Management District
Application Number 15487

December 8, 2008

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I. INTRODUCTION

The Bay Area Air Quality Management District ("Air District") is proposing to issue an amended Prevention of Significant Deterioration Permit ("Federal PSD Permit") for the Russell City Energy Center. The Russell City Energy Center, described in detail in subsequent sections of this document, is a proposed 600 megawatt natural gas fired combined-cycle power plant, proposed to be built near the corner of Depot Road and Cabot Boulevard, in Hayward, CA. The Air District is issuing a draft of an amended Federal PSD permit for the project, and is providing an opportunity for the public to review and comment on the draft prior to the District's final decision on the permit. This document is the Air District's Statement of Basis for the proposed permit.

This Statement of Basis has been prepared in accordance with Sections 124.7 and 124.8 of Title 40 of the Code of Federal Regulations, which set forth the procedural requirements for issuing Federal PSD Permits. The purpose of this Statement of Basis is to briefly set forth the principal facts and the significant factual, legal, methodological and policy questions that the Air District has considered in preparing the draft permit, and to briefly describe the derivation of the draft permit conditions and the reasons for them.[1] The Statement of Basis documents the Air District's proposed decision to issue the Federal PSD Permit in order to provide the public an opportunity to comment on it.

Following this Introduction, Section II outlines the legal framework for Federal PSD Permits and other environmental permitting requirements for power plants, such as the proposed Russell City Energy Center. This section describes the permitting action that the Air District is proposing in the context of the other permits and approvals that have been granted for the project, including the California Energy Commission's license for the project. Section II also discusses how the public can participate in the permitting process and provide input to the Air District on the current proposal.

Sections III and IV provide a detailed description of the proposed Russell City Energy Center project and the air emissions that the project would entail. Section III provides an overview of the power plant and explains what equipment would be installed and how it would operate. Section IV describes the maximum air pollutant amounts that the project would emit, and explains which emissions are subject to the Federal PSD Regulations.

Sections V and VI then describe how the Federal PSD Permit requirements apply to the project. Section V discusses the "Best Available Control Technology" requirements and how they apply to the equipment at the proposed facility. Section VI follows with a discussion of the Air Quality

[1] 40 C.F.R. sections 124.7 and 124.8 require that a Federal PSD permitting agency prepare either a "statement of basis" or a "fact sheet" to document its permitting decisions. The Air District normally uses the term "statement of basis" to refer to a more comprehensive document than a "fact sheet", which the Air District usually considers to be a brief overview rather than a detailed statement of reasons underlying a permitting decision. Given the Air District's historical practice regarding these terms, the Air District has titled this document a "Statement of Basis" for the permit, even though the Federal PSD regulations appear to contemplate that a document called a "fact sheet" should be more detailed and comprehensive than a "statement of basis". These semantic issues notwithstanding, the Air District considers this document to be its full explanation of its proposed permitting decision and the reasons for it, and intends it to satisfy all of the requirements in 40 C.F.R. sections 124.7 and 124.8. The Air District is also issuing a separate, shorter document entitled "fact sheet" to provide the public with a brief overview of the important aspects of the project. That "fact sheet" is not intended to discuss all the detailed information required by 40 C.F.R. section 124 provided in this document.

Impact Analyses that the Air District has conducted for the proposed facility as required by the Federal PSD Regulations.

Section VII then notes some additional legal requirements outside of the Federal PSD Permit program that are applicable to this project, including environmental justice concerns. Section VIII sets forth the proposed permit conditions for the facility. Section IX concludes with the Air District's proposal to issue a Federal PSD Permit for the project.

The Air District encourages all interested members of the public to review this document and learn about the project and the proposed amended Federal PSD Permit. The Air District also invites all interested members of the public to comment on any aspect of the proposal to issue the permit. Comments on the permit may be submitted to the District in writing or in person at the public hearing (*see* Section II below for more information).

II. LEGAL FRAMEWORK FOR PSD PERMITTING and OPPORTUNITIES FOR PUBLIC PARTICIPATION

Power plant permitting in California involves various state and federal agencies and multiple overlapping regulatory requirements, including the Federal PSD Permit requirements. This section provides background information on the permitting process and the regulatory requirements for issuing a Federal PSD Permit, as well as the public participation process.

A. POWER PLANT PERMITTING IN CALIFORNIA

The California Energy Commission ("Energy Commission" or "CEC") is the primary permitting authority for new power plants in California. The California Legislature has granted the Energy Commission exclusive licensing authority for all thermal power plants in California of 50 megawatts or more. (*See* Warren-Alquist State Energy Resources Conservation and Development Act, Cal. Public Resources Code §§ 25000 *et seq.*) This licensing authority supersedes all other local and state permitting authority. The intent behind this system is to streamline the licensing process for new power plants while at the same time providing for a comprehensive review of potential environmental and other impacts.

As the lead permitting agency, the CEC conducts an in-depth review of environmental and other issues implicated by the proposed power plant. This comprehensive environmental review is the equivalent of the review required for major projects under the California Environmental Quality Act ("CEQA"), and the Energy Commission's license satisfies the requirements of CEQA for these projects. This CEQA-equivalent review encompasses air quality issues within the purview of the Air District, and also includes all other types of environmental and other issues, including water quality issues, endangered species issues, and land use issues, among others.

The Air District collaborates with the Energy Commission regarding the air quality portion of its environmental analysis and prepares a "Determination of Compliance" that outlines whether and how the proposed project will comply with applicable air quality regulatory requirements. The Determination of Compliance is used by the Energy Commission to assess air quality issues of the proposed power plant.

The Air District also takes two important permitting actions that complement the Energy Commission's license. First, although the Warren-Alquist Act supersedes all other *state-law* permitting requirements, under the Constitution a state legislature cannot preempt federal law. For this reason, the Warren-Alquist Act cannot override federal permit requirements under the Clean Air Act, including the Federal PSD Permit requirement under Clean Air Act Section 165 and U.S. Environmental Protection Agency ("EPA") regulations in Section 52.21 of Title 40 of the Code of Federal Regulations. Proposed power plant projects must obtain Federal PSD Permits (if they are large enough to be subject to the Federal PSD Permit program) issued under EPA's jurisdiction pursuant to the Clean Air Act and its implementing regulations, notwithstanding the state-law CEC licensing process. EPA has delegated federal PSD permitting authority to the Air District for projects in the San Francisco Bay Area. (*See* U.S. EPA – Bay Area Air Quality Management District Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21, (February 6,

2008) ("Delegation Agreement").) A proposed power plant projects must therefore obtain a Federal PSD Permit from the Air District as a requirement of federal law, in addition to the CEC license.

Second, once the Energy Commission grants a license for a power plant, the Air District incorporates the conditions of certification addressing air quality issues into an Authority to Construct permit. (*See* District Regulation 2-3-405.) The District needs to incorporate the conditions of certification into a District permit to make them enforceable by District inspectors, as only permit conditions in District-issued permits and not in CEC-issued licenses can be enforced by the District. (*See* California Health & Safety Code §§ 42302-42302.3.) This issuance is a limited, ministerial action consisting simply of making a final check to ensure that all applicable conditions were correctly incorporated into the CEC certification. If so, the District issues the Authority to Construct and the air-quality related permit conditions become enforceable by the District under the California Health & Safety Code.

Both the Energy Commission licensing process and the Federal PSD Permit process provide opportunities for public participation. Both processes require the permitting agencies to notify the public of the permit proceeding and invite the public to submit comments on whether a permit should be issued and what permit conditions it should contain. Those who participate in these proceedings and are dissatisfied with the final permit decisions have a right to appeal the decisions. The Energy Commission's licensing decision is appealable directly to the California Supreme Court. The Air District Authority to Construct is appealable to the District's Hearing Board and subsequently to the Superior Court of California. Federal PSD Permits are initially appealable the EPA's Environmental Appeals Board in Washington, D.C., and subsequently to federal court.[2]

B. RUSSELL CITY ENERGY CENTER PERMITTING HISTORY

The proposed Russell City facility was initially licensed in 2002, but it was relocated and so its permits had to be updated. The CEC and the Air District therefore reinitiated the permitting process outlined above to amend the initial permits to reflect the new location. The District prepared a Determination of Compliance addressing air quality issues raised (as well as a few minor changes in the operating conditions) by the permit amendment and submitted it to the Energy Commission for use in the licensing proceeding. The Energy Commission completed its CEQA-equivalent review of environmental impacts (including air quality issues) and ultimately approved the amendment on September 26, 2007. On November 1, 2007, the Air District issued an amended Authority to Construct incorporating the Energy Commission's conditions of certification into a District-issued permit, and also issued the amended Federal PSD Permit for the project. The amended Authority to Construct and the amended Federal PSD Permit were issued jointly in the same document, in accordance with the Air District's administrative practice.

A number of parties then sought review of these permitting actions. On the state-law side, a group of interested organizations attempted to seek reconsideration of the Energy Commission's decision to license the project, but the Energy Commission declined to hear their request. The group then

[2] The Air District's ministerial Authority to Construct permit is appealable only on the narrow issue of whether the Air District correctly incorporated the Energy Commission's conditions of certification in the Authority To Construct. That is, an error in transcribing a permit condition from the Energy Commission's license into the Authority to Construct is appealable, but an appeal cannot seek to revisit substantive issues of what permit conditions are appropriate and required, which are addressed during the CEC licensing process and on any appeals therefrom.

appealed the denial to the California Supreme Court, but the Supreme Court dismissed their petition. One person also appealed the Air District's issuance of the Authority to Construct to the District's Hearing Board, but his appeal was denied and he did not seek further review. All appeal avenues have therefore been exhausted, and the state-law Energy Commission license and District Authority to Construct are not subject to further review.

With respect to the Federal PSD Permit, one person appealed the permit to the Environmental Appeals Board raising issues concerning the public notice and comment process (among other, substantive issues). The Environmental Appeals Board ruled that the Air District had not mailed notice of the proposed amended Federal PSD Permit to several parties that were entitled to it, and so it remanded the permit to the District to re-notice the proposed permit and provide the public with a further opportunity to comment. (*See* Remand Order, *In re Russell City Energy Center*, PSD Appeal No. 08-01 (EAB Jul. 29, 2008) ("Remand Order").[3]) The Air District is re-noticing the proposed amended Federal PSD Permit at this time in response to the Remand Order.

C. THE CURRENT PROPOSED AMENDED PERMIT

The Air District is re-proposing to issue the Federal PSD Permit for the Russell City Energy Center in response to the Order of the Environmental Appeals Board. The Air District is complying with all of the detailed public notice requirements for this proposal, as directed by the Environmental Appeals Board. In accordance with Sections 52.21 and 124.10 of Title 40 of the Code of Federal Regulations, the Air District is proposing to issue the amended permit, publishing notice of its proposal, and inviting public comments on the proposal. Details on how the public can learn more about the project and submit comments about the proposed amended Federal PSD Permit are set forth in Section II.D.

The amendments that have been proposed to the Federal PSD Permit are outlined in detail in the subsequent portions of this document. The Air District is also describing in detail a number of aspects of the project that are not being amended, in order to provide complete information in a single location. The analysis of elements that are not being amended shows that the conditions from the initial permit that are not being changed meet current applicable legal standards for Federal PSD Permits, and that they would comply with current PSD requirements even if they were being proposed anew at this time.

The Air District is not reopening the state-law permitting process that was completed under the Warren-Alquist Act (culminating with the Energy Commission's license for the project and the District's incorporation of the Energy Commission's licensing conditions into the Authority to Construct permit). Those permitting actions under state law are final and all avenues for appeal have been exhausted. The Environmental Appeals Board's remand of the Federal PSD Permit to be re-noticed does not implicate these state-law permits. They are separate legal entities and the Environmental Appeals Board has not questioned their continued validity. The Environmental Appeals Board affirmed the distinction between these two permitting systems in its Remand Order,

[3] The EAB's Remand Order is available on the EAB's website at www.epa.gov/eab. The EAB may also be contacted at 1341 G Street N.W., Washington, D.C., 20005, (202) 233-0122. The public may also be interested in examining the EAB's document "A Citizen's Guide to the Environmental Appeals Board" for more information about the EAB and how it works.

explaining that "[t]he Board will deny review of issues that are not governed by the PSD regulations because it lacks jurisdiction over them." (*See* Remand Order, Slip Op. at p. 40.) It further explained that where a permit requirement is "a California rather than a federal PSD requirement, [it] consequently is not reviewable by the Board." (*See id.*, Slip Op. at p. 41.) As these passages explain, the CEC licensing requirements under the Warren-Alquist Act are state-law requirements outside of the Federal PSD Permit process and are not part of the Environmental Review Board's remand.

D. OPPORTUNITIES FOR PUBLIC PARTICIPATION AND COMMENT ON THE DISTRICT'S PROPOSAL

The District invites all interested parties to comment on the Draft Amended PSD Permit. The legal requirements for PSD Permits are contained in Section 52.21 of Title 40 of the Code of Federal Regulations (40 C.F.R. section 52.21). Comments should address only the Federal PSD issues in this proceeding. The District is not considering any issues related to the state-law Authority to Construct permit or the California Energy Commission's license for the project, or any other non-PSD issues. The EAB provided examples of such non-PSD issues in Section IV.E of its Remand Order. (*See* Remand Order, *In re Russell City Energy Center*, PSD Appeal No. 08-01, Slip Op. at p. 40 (EAB Jul. 29, 2008).) For a complete determination of what are and are not PSD issues, interested parties should consult the EAB's order, 40 C.F.R. section 52.21, other relevant EAB decisions, and related authorities.

Written comments should be directed to Weyman Lee, P.E., Senior Air Quality Engineer, Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA, 94109, (415) 749-4796, weyman@baaqmd.gov. The Air District will publish the deadline for submitting written comment in a formal legal notice; interested parties may contact Mr. Lee for further information. The permit application and other materials on which the proposed permit is based will be made available for public review at the District's headquarters at the above address. Interested parties who would like to review such materials should contact the District's public records coordinator by telephone at (415) 749-4761, or electronically at publicrecords@baaqmd.gov. The District will also be holding a public hearing to allow interested parties to comment on the Draft Amended PSD Permit in person. Further information on the date and location of the public hearing will be published with the formal legal notice. The District will consider all comments from all interested parties, whether in writing during the written comment period or orally at the hearing.

III. PROJECT DESCRIPTION

The Russell City Energy Center is a proposed 600 megawatt ("MW") natural gas fired combined-cycle power plant proposed to be built by Russell City Energy Company, LLC, which is owned 65% by a subsidiary of Calpine Corporation and 35% by General Electric Corporation. The proposed facility would be located at 3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in Hayward, CA. (A full description of the facility and its air emissions is provided in Sections III and IV below.) The facility was originally permitted in 2002, but was subsequently relocated approximately 1,500 feet north of the original site and required the facility's permits to be amended.

The proposed facility would be a combined-cycle combustion turbine power generation facility with a nominal electrical output of 600 MW. As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 200 MW and the steam produced by the heat recovery steam generators (HRSGs) will feed to a steam turbine generator with a rated electrical output of 235 MW.

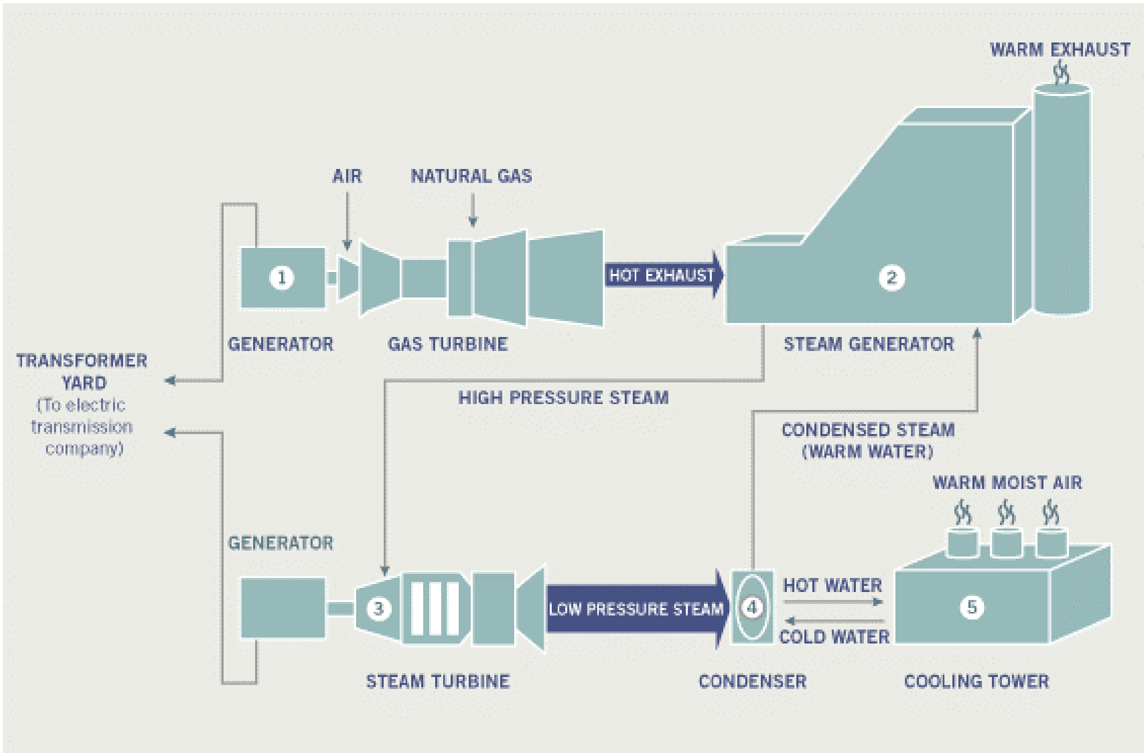
The Russell City Energy Center is proposed to include two gas turbines, a single steam turbine, two heat recovery steam generators (HRSG) or waste heat boilers, a cooling tower, and a diesel fire pump engine. The facility would be considered a combined cycle power plant in which the gas turbines generate electricity and the heat from the gas turbine exhaust is used to produce steam in the heat recovery steam generator to generate additional electricity via the steam turbine. The recovery of energy from the gas turbine exhaust, which otherwise would be wasted, increases the efficiency of electrical generation.

The gas turbines burn natural gas to rotate an electrical generator to generate electricity. The main components of a turbine consist of a compressor, combustor, and turbine. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the power turbine where the gases expand across the turbine blades, driving one or more shafts to power an electric generator.

The waste heat in the exhaust from the gas turbines is sent to the heat recovery steam generator that produces steam that is sent to a steam turbine to generate additional electricity. The heat recovery steam generator has an additional duct burner that provides supplemental heat to create more steam during times of peak energy demand.

The facility would have a cooling tower that acts as a heat exchanger by circulating water to cool various equipment at the site. The cooling tower also recondenses the steam/condensate from the steam turbine and recycles this water back to the heat recovery steam generator. The facility also would have a 300 hp diesel engine to power a fire pump onsite to be used in case of emergency to provide water to fight fires.

The schematic diagram below illustrates how a combined-cycle combustion turbine power plant works.



The Russell City Energy Center will consist of the following permitted equipment:

S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst

S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute

S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input.

Operating Scenarios:

The exact operation of the new gas turbine/HRSG power trains will be dictated by market circumstances and demand. However, the following general operating modes are expected to occur at the RCEC:

Base Load: Maximum continuous output with duct firing

Load Following: Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario

Partial Shutdown: Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during periods of low overall demand such as late evening and early morning hours

Full Shutdown: May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation

IV. FACILITY AIR EMISSIONS

This section summarizes the proposed facility's air emissions. This summary includes both air emissions subject to Federal PSD requirements and air emissions not covered by the Federal PSD Program. Emissions in the latter category are subject to applicable permitting requirements under other legal requirements, and are summarized here to provide a complete picture of the facility's proposed emissions. The emissions specifically subject to Federal PSD permitting requirements are identified at the end of this section, in Subsection IV.D.

A. CRITERIA AIR POLLUTANTS

In this section, the Air District provides an overview of the proposed project's emissions of air pollutants known as "criteria" air pollutants. In general, criteria pollutants are regional air pollution problems for which California and the federal government have established ambient air quality standards.

1. Maximum Hourly Emissions

The facility's maximum hourly emissions from the combustion turbines and heat recovery boilers under various operating scenarios are set forth in the tables below.

Table 1 is a summary of maximum hourly emissions from the facility during normal (baseload) operations.

Table 1: Steady-State Emissions Rates

Pollutant	Emissions Rate (lb/hr)[a]
NOx (as NO_2)	16.45
CO	19.96
POC (as CH_4)	2.86
PM_{10}	9.0
SOx (as SO_2)	6.2

[a]emission rates for gas turbine w/duct burner firing

Table 2 is a summary of maximum hourly emissions for startup and combustor tuning operations, as well as maximum total emissions per startup/tuning event.

Table 2: Startup and Tuning Emissions Rates

Pollutant	Cold Startup/Tuning[a]		Warm Startup[b]		Hot Startup[c]	
	lb/hr	lb/startup[g]	lb/hr	lb/startup	lb/hr	lb/startup
NOx (as NO_2)[d]	97.2	480.0	83.8	125	83.8	125
CO[d]	1348.8	5028	1154.2	2514	1154.2	2514
POC (as CH_4)[d]	14.9	83	26.3	79	14.8	35.3
PM_{10}[e]	9.0	54	9.0	27	9.0	27
SOx (as SO_2)[f]	6.2	33	6.2	16.5	6.2	16.5

[a] cold start not to exceed six hours (360 minutes); by definition, occurs after turbine has been inoperative for at least 72 hours. Combustor tuning not to exceed six hours (360 minutes).
[b] warm starts not to exceed 3 hours (180 minutes); by definition occurs between 8 and 72 hours of a shutdown.
[c] hot starts not to exceed 3 hours (180 minutes); by definition, occurs within 8 hours of a shutdown.
[d] maximum hourly emissions for NO_x, CO, and UHC provided by applicant.
[e] as a conservative estimate, based upon full load emission factor of 0.00424 lb PM_{10}/MM BTU and maximum heat input rate of 2038.6 MM BTU/hr
[f] based upon full load emission factor of 0.000693 lb SO_2/MM BTU and maximum heat input rate of 2038.6 MM BTU/hr
[g] emissions are not calculated by multiplying hourly rate by number of startup hours for NO_x, CO and UHC. These startup emissions are specified by applicant based on operational data. The startup NO_x emission limit has been adjusted from 240 lb/startup to 125 lb/startup to be consistent with CEC's conditions of certification.

Table 3 is a summary of maximum emissions per shutdown event.

Table 3: Maximum Emissions per Shutdown Event	
Pollutant	**lb/shutdown[a]**
NOx (as NO_2)	40[b]
CO	902
POC (as CH_4)	16
PM_{10}	4.5
SOx (as SO_2)	3.1

[a] Shutdowns not to exceed 30 minutes.
[b] The shutdown NO_x emissions limit has been adjusted from 80 lb/shutdown to 40 lb/shutdown to be consistent with CEC's conditions of certification.

2. Maximum Daily Air Emissions

Table 4 is a summary of the daily maximum criteria air pollutant emissions for the permitted sources at the proposed Russell City Energy Center.

Table 4: Maximum Daily Criteria Air Pollutant Emissions for Proposed Sources (lb/day)

	Pollutant (lb/day)				
Source	**Nitrogen Oxides (as NO_2)**	**Carbon Monoxide**	**Precursor Organic Compounds**	**Particulate Matter (PM_{10})**	**Sulfur Dioxide**
S-1 Gas Turbine & S-2 HRSG[a]	776	5387	148	216	148.8
S-3 Gas Turbine & S-4 HRSG[a]	776	5387	148	216	148.8
S-5 Cooling Tower[b]				68	
S-6 Fire Pump Diesel Engine[c]	2.82	0.22	0.21	0.079	0.0033

[a] NOx, CO, and POC emission rates are based upon one 360 minute cold start-up and 18 hours of Gas Turbine /HRSG full load operation at maximum combined firing rate of 2,238.6 MM BTU/hr in one day; PM_{10} and SO_2 emission rates are based upon 24 hours of Gas Turbine/HRSG baseload operation at maximum combined firing rate of 2,238.6 MM BTU/hr in one day
[b] emission rates based upon 24 hr/day operation at maximum emission rates; see Appendix B, Section 4.0 for emissions calculations

[c] emission rates based upon 1 hr/day operation at maximum emission rates

3. Maximum Annual Air Emissions

Table 5 below summarizes the maximum operating annual air pollutant emissions for the proposed project. This table reflects two minor changes from the project as initially permitted: The Carbon Monoxide emissions have decreased from 584.2 tons/year to 389.3 tons/year, and the Particulate Matter emissions have increased slightly from 86.4 tons/year to 86.8 tons/year. All other emission rates are unchanged from the project as initially permitted.

Table 5: Maximum Annual Emissions of Criteria Air Pollutants

NO_2 (ton/yr)	CO (ton/yr)	POC (ton/yr)	PM_{10} (ton/yr)	SO_2 (ton/yr)
134.6	**389.3**	**28.5**	**86.8**	**12.2**

B. TOXIC AIR CONTAMINANT (TAC) EMISSIONS

Toxic Air Contaminants (TACs) are a subset of air pollutants that can be harmful to health and the environment even in very small amounts. **Table 6** provides a summary of the maximum annual facility toxic air contaminant (TAC) emissions from the project.

Table 6 also provides the TAC emission rates that the Air District used as the basis for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. This health risk assessment is required by District Regulation 2, Rule 5. The health risk assessment is conducted to determine the potential impact on public health resulting from the worst-case TAC emissions from the project. If emissions are above certain established screening levels prescribed in Table 2-5-1 of Regulation 2, Rule 2, a health risk assessment is required. The applicable screening levels from Table 2-5-1 are also included in Table 6. Where no acute trigger level is listed for a TAC, none has been established for that TAC.

Table 6: Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	Total Project Emissions (lb/yr)	Chronic Trigger Level (lb/yr-project)	Total Project Emissions (lb/hr)	Acute (1 hour max.) Trigger Level (lb/hr)
Turbines/HRSGs				
Acetaldehyde	2330	64		
Acrolein	321	2.3	0.0403	0.00042
Ammonia	121000	7700	15.2	7.1
Benzene	226	6.4	0.0284	2.9
1,3-Butadiene	2.16	1.1		
Ethylbenzene	304	77000		
Formaldehyde	15600	30	1.96	0.21

Table 6: Maximum Facility Toxic Air Contaminant (TAC) Emissions				
Toxic Air Contaminant	**Total Project Emissions (lb/yr)**	**Chronic Trigger Level (lb/yr-project)**	**Total Project Emissions (lb/hr)**	**Acute (1 hour max.) Trigger Level (lb/hr)**
Hexane	4400	270000		
Naphthalene	28.2	0.011		
Total PAHs	1.8	0.011		
Propylene	13100	0.012		
Propylene Oxide	813	49	0.102	6.8
Toluene	1210	12	0.151	82
Xylenes	408	27000		
Cooling Tower				
Ammonia	186	7700	0.0212	7.1
Arsenic	0.155	0.012	0.0000177	0.00042
Cadmium	0.248	0.045		
Hexavalent chromium	1.27	0.0013		
Copper	1.88	93		
Lead	0.588	5.4	0.0000671	0.22
Manganese	2.58	7.7		
Mercury	0.00186	0.56		
Nickel	1.45	0.73	0.000166	0.013
Selenium	0.216	770		
Zinc	5.94	1400		
Firepump Engine				
Diesel Exhaust Particulate	4	0.58		

Notes: The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 5 ppmvd @ 15% O_2 due to ammonia slip from the A-1 and A-3 SCR Systems. The chronic and acute screening trigger levels shown are per Table 2-5.1 of Air District Regulation 2, Rule 5.

Table 7 is a summary of the health risk assessment results.

Table 7: Health Risk Assessment Results

Receptor	Cancer Risk (risk in one million)	Chronic Non-Cancer Hazard Index (risk in one million)	Acute Non-Cancer Hazard Index (risk in one million)
Maximally Exposed Individual	0.7	0.007	0.024
Resident	≤ 0.7	≤ 0.007	≤ 0.024
Worker	≤ 0.7	≤ 0.007	≤ 0.024

Pursuant to BAAQMD Regulation 2-5, the increased carcinogenic risk attributed to this project is not significant since it is less than 1.0 in one million. The chronic hazard index and the acute hazard index attributed to the emission of non-carcinogenic air contaminants not significant since each is less than 1.0. These levels of risk are less than significant.

C. SECONDARY EMISSIONS AND EMISSIONS FROM GROWTH ASSOCIATED WITH THE PROJECT

The Federal PSD Regulations require that the District's analysis of the emissions from the proposed project include "secondary emissions" associated with the project and emissions from "general commercial, residential, industrial and other growth associated with the project." (*See* 40 C.F.R. §§ 52.21(k) & 52.21(o)).

Secondary Emissions

"Secondary Emissions" are emissions that are associated with a source but are not emitted from the source itself. They are emissions from any facility that is not part of the source subject to the Federal PSD Permit, but which would not be constructed unless the facility under review is conducted. The proposed Russell City Energy Center will not have any such secondary emissions.

Associated Growth

"Associated Growth" is additional commercial, residential, industrial and other growth that the project may cause or induce. This type of growth is growth in the local workforce and support infrastructure necessary to serve the proposed facility. Examples include additional residential housing, retail suppliers, and additional schools and municipal services that would be necessary to accommodate any new workers that would come to the area to work in the facility. Examples also include any additional commerce or industry necessary to provide goods and services used by the facility, maintenance facilities to serve the facility, and other similar support operations. Emissions from "associate growth" are the emissions associated with this additional human and economic activity generated as a result of the facility under review. The Air District undertook an associated growth analysis and found that there would be no significant associated growth.[4]

D. AIR EMISSIONS SUBJECT TO FEDERAL PSD PERMIT REQUIREMENTS

[4] *See* Air Quality Impacts Analysis, Exhibit C.

1. Emissions Regulated Under the Federal PSD Program

The Federal PSD Program does not apply to all air pollutants. The program does not apply to air pollutants for which the ambient air quality in the Bay Area exceeds the health-based National Ambient Air Quality Standards ("NAAQS"). For air pollutants for which the Bay Area exceeds those standards – for which we are designated as "non-attainment" – the District's "New Source Review" regulations apply, which have additional requirements beyond the Federal PSD Program such as providing Emission Reduction Credits to offset emissions from new projects. The Federal PSD Program applies only to those pollutants for which the District is designated as being in "attainment" of the NAAQS, or for which EPA has made no formal designation of "attainment" or "non-attainment". The Bay Area is currently designated as "non-attainment" for ozone, meaning that ozone and its precursors (NOx and VOC) are not subject to PSD review.[5]

Furthermore, the Federal PSD Permit Regulations apply only to facilities that are considered "major sources" of PSD-regulated air pollutants Regulations. A proposed power plant is considered a "major source" if it would emit more than 100 tons per year of any Regulated Air Pollutants. (*See* 40 C.F.R. § 52.21(b)(1)(i)(a).) The main substantive requirements of the Federal PSD Permit program – the use of Best Available Control Technology to minimize emissions of Federal PSD Pollutants and an Air Quality Impact Analysis of the effect of the source on ambient air quality – apply where the source will emit Regulated Air Pollutants in "significant" amounts as set forth in Section 52.21(b)(23).

In addition, EPA has provided special regulatory direction for Federal PSD Permits for one specific regulated air pollutant that is implicated in this Federal PSD Permit analysis, Particulate Matter. EPA has long regulated one subset of Particulate Matter, particulate matter of less than 10 microns in diameter (PM_{10}). Recently, a related subset of Particulate Matter has recently come under heightened regulatory scrutiny, Particulate Matter of less than 2.5 microns in diameter ($PM_{2.5}$). EPA promulgated National Ambient Air Quality Standards ("NAAQS") for $PM_{2.5}$ in 1997 (with an update in 2006), and designated certain regions of the country as non-attainment with those Standards in 2005. The Bay Area was not designated as non-attainment, and is currently unclassified for purposes of attainment of the 24-hour NAAQS for $PM_{2.5}$, which means that $PM_{2.5}$ falls under the federal PSD program as set forth in 40 C.F.R. section 52.21.

EPA has recognized, however, that there are a number of difficulties involved in regulating $PM_{2.5}$ as a distinct pollutant from PM_{10}, including a lack of adequate tools to calculate emissions of $PM_{2.5}$ and related precursors, a lack of adequate modeling techniques to project ambient impacts, and a lack of $PM_{2.5}$ monitoring sites. EPA has therefore directed that implementing agencies should use PM_{10} as a surrogate for analyzing $PM_{2.5}$ emissions and impacts for PSD purposes in guidance issued October 23, 1997.[6] EPA recently promulgated new amendments to the PSD regulations addressing $PM_{2.5}$, and these amendments expressly incorporated the earlier guidance and made clear that for permit

[5] For information on the Bay Area's attainment status for various air pollutants, including attainment of both state and federal ambient air quality standards, see http://www.baaqmd.gov/pln/air_quality/ambient_air_quality.htm.

[6] Memorandum from John Seitz, Director of EPA Office of Air Quality Protection and Standards, to EPA Regional Staff, entitled "Interim Implementation of New Source Review Requirements for $PM_{2.5}$" (Oct. 23, 1997).

applications such as this one that were submitted and complete before July 15, 2008, permitting agencies should use the PM_{10} surrogate approach from the 1997 guidance.[7]

Furthermore, it is worth noting that use of PM_{10} as a surrogate for $PM_{2.5}$ is especially appropriate in this instance because for combustion sources such as those that will be used at the Russell City Energy Center fired on clean-burning natural gas, the majority of particulate matter emissions will have a diameter of less than 1 micron. (*See* EPA AP-42 Emission Factors, Section 1.4, 7/98.) As this particulate matter is less than 1 micron in diameter, by definition it has a diameter of less than 2.5 microns and less than 10 microns, and so it is *both* $PM_{2.5}$ and PM_{10}. The analysis of potential PM_{10} impacts is therefore a useful and appropriate surrogate for potential $PM_{2.5}$ impacts from power plant projects such as the Russell City Energy Center.

For all of these reasons, the District is following a PM_{10} surrogate approach. The District is analyzing PM_{10} emissions and related impacts as a surrogate for $PM_{2.5}$ emissions and impacts, and is implementing applicable PM_{10} PSD regulatory requirements as a surrogate for PSD for $PM_{2.5}$. Throughout this document, the District uses the generic reference "Particulate Matter" to include both PM_{10} and $PM_{2.5}$.

2. Russell City Emissions Subject to PSD Permitting Requirements

Under this regulatory framework, the Federal PSD Permit analysis applies only to regulated air pollutants for which the Bay Area is not designated as "non-attainment" of an established NAAQS and which will be emitted in "significant" amounts from a "major facility".[8] **Table 8** compares the emissions from the proposed Russell City Energy Center (excluding the "non-attainment" pollutants referenced above) with the applicable PSD "Major Facility" and "Significance" thresholds published in 40 C.F.R. Sections 52.21(b)(1) and (b)(23).[9]

Table 8:
Maximum Annual Facility Regulated Air Pollutant Emissions

[7] *See* 73 Fed. Reg. 28231, 28349-50 (May 16, 2008) (to be codified at 40 C.F.R. § 52.21(i)(1)(xi)). The Air District expects shortly to be classified as "attainment" or "non-attainment" of the new $PM_{2.5}$ standard by EPA. If the District is classified as "non-attainment", $PM_{2.5}$ will be regulated under the District's NSR permitting program and will no longer be subject to PSD permit requirements. Permit applications such as this one that were received under the existing designation will continue to be processed under the PSD program using the surrogate approach as directed by EPA, however.

[8] Note that the other air emissions not subject to the Federal PSD Permit analysis are not unregulated. They are subject to other stringent regulatory requirements under state law.

[9] Emissions rates in Table 8 are based on the emissions rates set forth in Section IV.A. above with one exception, sulfuric acid mist (H_2SO_4). Emissions of sulfuric acid mist are expected to be less than the PSD significance threshold of 7 tons per year, and the Air District is proposing an enforceable permit condition (Number 25) limiting sulfuric acid mist from the new combustion units to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from annual compliance source tests. The annual source test will be conducted, as indicated in Condition number 34, to measure SO_2, SO_3, H_2SO_4 and ammonium sulfates. This approach is necessary because the conversion in turbines of fuel sulfur to SO_3, and then to H_2SO_4 is not well established. With this permit condition, sulfuric acid mist emissions will be less than the PSD significance threshold of 7 tons per year and the facility will not be subject to Federal PSD Permit requirements for sulfuric acid mist.

Pollutant	Emissions (tons/year)	PSD "Major Facility" Trigger (tons/year)	PSD "Significance" Threshold (tons/yr)
Nitrogen Dioxide (NO_2)	134.6	100	40
Carbon Monoxide (CO)	389.3	100	100
Particulate Matter (PM_{10})	86.8	100	15
Sulfur Dioxide (SO_2)	12.2	100	40
Sulfuric acid mist (H_2SO_4)	<7	100	7

As Table 8 shows, the proposed facility will be considered a "major facility" subject to PSD permitting requirements because it exceeds the 100 tons-per-year threshold. Emissions will be "significant" for NO_2, Carbon Monoxide and Particulate Matter.

V. FEDERAL "BEST AVAILABLE CONTROL TECHNOLOGY" ANALYSIS

The Federal PSD Regulations (40 C.F.R. Section 52.21) require that a new major stationary source such as the Russell City Energy Center apply the "Best Available Control Technology" for each regulated pollutant that it will have the potential to emit in significant amounts. As noted above, the Russell City Energy Center will have the potential to emit three pollutants subject the Federal PSD regulation in significant amounts: NO_2, Carbon Monoxide, and Particulate Matter. The facility must therefore demonstrate that it will use the "Best Available Control Technology" to limit emissions of those three pollutants.

The Federal PSD Regulation defines "Best Available Control Technology" as:

> An emissions limitation . . . based on the maximum degree of reduction for each pollutant subject to regulation under Act [sic] which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

EPA has provided further guidance on how to implement this definition of "Best Available Control Technology" in its 1990 Draft New Source Review Workshop Manual ("NSR Workshop Manual"). EPA requires that the District implement the Best Available Control Technology requirement by conducting what EPA calls a "Top-Down BACT Analysis". As described in EPA's NSR Workshop Manual, a "Top-Down BACT Analysis" consists of five key steps:

1. **Identify control technologies** including Lowest Achievable Emission Rate (LAER) technologies.
2. **Eliminate technically infeasible options.**
3. **Rank remaining control technologies by control effectiveness.** This ranking should include control efficiencies, expected emission rate, expected emissions reduction, energy impacts, environmental impacts, and economic impacts. If the top control alternative is chosen, then cost and other detailed information about other control options need not be provided.
4. **Evaluate the most effective controls and document results.** Analysis to include a case-by-case consideration of energy, environmental, and economic impacts. If the top control alternative is selected, other potential impacts are considered to determine if the selection of an alternative control option can be justified. If the top control option is not selected as BACT, evaluate the next most effective control option.

   The cost estimation methodology used in this BACT analysis is consistent with the latest EPA guidance (EPA's Office of Air Quality Planning and Standards [OAQPS] Control Cost Manual [EPA 453/b-96-001]), and the District's BACT handbook.

5. **Select the "Best Available Control Technology"**, which will be the most effective option not rejected in Step 4.

Once the selection of "Best Available Control Technology" is made under the "Top-Down BACT Analysis", the Air District is then required to derive a numerical emissions limit that can be achieved by the selected control technology (or some other type of enforceable limit if a numerical limit is not feasible), and then implement that emissions limit in a legally-enforceable condition in the Federal PSD Permit.

The Air District's "Best Available Control Technology" analysis for the three Federal PSD Permit pollutants (NO_2, Carbon Monoxide and Particulate Matter) is set forth in this section. The District has examined the Best Available Control Technology for each of the types of equipment at the facility that will have air emissions: the gas turbine/heat recovery boiler power generation equipment; the cooling tower; and the emergency diesel fire pump.

A. Gas Turbine/Heat Recovery Boiler Power Generation Equipment

The following section provides the District's BACT analysis for the project's gas turbines and heat recovery boiler duct burners for each of the three Federal PSD Permit pollutants. Each gas turbine/heat recovery boiler combination will have a common exhaust stream and exhaust through a common stack, and so the BACT analyses are undertaken for the Gas Turbine/Heat Recovery Boiler power train as a combined unit.

1. Best Available Control Technology for Nitrogen Dioxide (NO_2)

NO_2 emissions are a byproduct of the combustion of an air-and-fuel mixture in a high-temperature environment. NO_2 is formed when the heat of combustion causes the nitrogen molecules in the combustion air to dissociate into individual nitrogen atoms, which then combine with oxygen atoms form nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as nitrogen oxides (NO_x).[10] This reaction primarily forms NO (95% to 98%) and only a small amount of NO_2 (2% to 5%), but the NO eventually oxidizes and converts to NO_2 in the atmosphere.

NO_2 is a reddish-brown gas with detectable odor at very low concentrations, and is regulated as an air pollutant in its own right. NO_2 is also regulated (along with NO) as a precursor to the formation of ground-level ozone, the principal ingredient in smog.[11] In the context of ozone precursor regulation, NO_2 and NO emissions are generally referred to collectively as "NO_x". As the NO portion of NO_x eventually converts to NO_2, and as permit limits for NOx are normally expressed in terms of NO_2, the Air District refers to NO_x and NO_2 interchangeably in this analysis. The

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[10] NO_x can also be formed when a nitrogen-bound hydrocarbon fuel is combusted, resulting in the release of nitrogen atoms from the fuel (fuel NO_x). NO_x can also be formed by organic free radicals and nitrogen in the earliest stages of combustion (prompt NO_x). Natural gas does not contain fuel-bound nitrogen, however, and so thermal NO_x is the primary formation mechanism for this project. References to NO_x formation during combustion in this analysis refer to "thermal NO_x", NO_x formed from nitrogen in the combustion air.

[11] NOx emissions as an ozone precursor are regulated under California law through the Energy Commission Licensing process and subsequent Air District Authority to Construct permit (discussed in more detail in Section II.A above). NO_2 is regulated under the Federal PSD program for sources in the Bay Area.

technologies that are effective to target NO_2 as a pollutant in its own right are the same technologies that are effective to target NO_x as an ozone precursor.

STEP ONE: Identify Control Technologies

The Air District has examined technologies that may be effective to control NOx emissions in two general areas: combustion controls that will minimize the amount of NOx created during combustion; and post-combustion controls that can remove NOx from the exhaust stream after combustion occurs.

Combustion Controls

The formation of NO_x during combustion is highly dependent on the primary combustion zone temperature, as the formation of NO_x increases exponentially with temperature. There are therefore three basic strategies to reduce thermal NO_x in the combustion process:

- Reduce the peak combustion temperature;
- Reduce the amount of time the air/fuel mixture spends exposed to the high combustion temperature;
- Reduce the oxygen level in the primary combustion zone.

It should be noted, however, that techniques that control NOx by reducing combustion temperature could involve a trade-off with the formation of other pollutants. Reducing combustion temperature to limit NOx formation can decrease combustion efficiency, resulting in increased byproducts of incomplete combustion such as Carbon Monoxide and unburned hydrocarbons. (Unburned hydrocarbons from natural gas combustion consist of methane, ethane and Precursor Organic Compounds.) The Air District prioritizes NOx reductions over Carbon Monoxide and POC emissions, however, because the Bay Area is not in compliance with applicable ozone standards but does comply with Carbon Monoxide standards. The Air District therefore requires applicants to minimize NOx emissions to the greatest extent feasible, and then optimize CO and POC emissions for that level of NOx control. This is a trade-off that must be kept in mind when selecting appropriate emissions control technologies for these pollutants.

The Air District has identified the following available combustion control technologies for reducing NOx emissions from the combustion turbines and heat recovery boiler duct burners.

Steam/Water Injection: Steam or water injection was one of the first NOx control techniques utilized on gas turbines. Water or steam is injected into the combustion zone to act as a heat sink, lowering the peak flame temperature and thus lowering the quantity of thermal NO_x formed. The injected water or steam exits the turbine as part of the exhaust. The lower peak flame temperature can also reduce combustion efficiency and prevent complete combustion, however, and so Carbon Monoxide and POC emissions can increase as water/steam-to-fuel ratios increase. In addition, the injected steam or water may cause flame instability and can cause the flame to quench (go out). This is especially a concern with the duct burners in the heat recovery boiler because they use turbine exhaust for their combustion air, which has a low oxygen content and is less able to support a stable flame. Also, the duct burners are comprised of many small modular burners located in the cross sectional area of the duct, and it is not feasible to inject steam/water since the flame is not concentrated. For these reasons, steam/water injection technology cannot be used for the duct burners.

Low-NOx Combustion Technology: Another technology that can control NOx without water/steam injection is low-NOx burner technology. For the combustion turbines, **Dry Low-NO_x Combustors** reduce the formation of thermal NO_x through (1) "lean combustion" that uses excess air to reduce the primary combustion temperature; (2) reduced combustor residence time to limit exposure in a high temperature environment; (3) "lean premixed combustion" that reduces the peak flame temperature by mixing fuel and air in an initial stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of oxygen available to combine with nitrogen and then a secondary lean burn-stage to complete combustion in a cooler environment. For the heat recovery boiler duct burners, **Low NO_x Duct Burners** are designed to minimize NO_x emissions. Duct burners in a heat recovery boiler are inherently lower in NO_x formation since the combustion air – turbine exhaust gas – has a lower oxygen content that results in lower flame temperatures.

Catalytic Combustors: Catalytic combustors, marketed under trade names such as XONON™, use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature in order to reduce thermal NO_x formation. XONON™ uses a flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst. This technology is available only for the combustion turbines; there are no catalytic combustor technologies for the heat recovery boiler duct burners.

Post-Combustion Controls

The Air District has identified the following post-combustion controls that can remove NOx from the emissions stream after it has been formed.

Selective Catalytic Reduction (SCR): Selective catalytic reduction injects ammonia into the exhaust stream, which reacts with the NOx and oxygen in the presence of a catalyst to form nitrogen and water. NOx conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask or poison the catalyst. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream as what is commonly called "ammonia slip". The SCR catalyst requires replacement periodically. SCR is a widely used post-combustion NO_x control technique on utility-scale gas turbines/HRSGs, usually in conjunction with combustion controls.

Selective non-catalytic reduction (SNCR): Selective non-catalytic reduction involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1400° to 2000° F and is most commonly used in boilers because combustion turbines do not have exhaust temperatures in that range.

EMx™: EMx™ (formerly SCONOx™) is a catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NO_x, CO, VOC and optionally SO_x emissions for gas turbine applications. A coated catalyst oxidizes NO to NO_2, CO to CO_2, and VOCs to CO_2 and water, and the NO_2 is then absorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. A proprietary regenerative gas is periodically passed through the catalyst to desorb the NO_2 from the catalyst and reduce it to elemental nitrogen (N_2). No ammonia is used by the EMx process. The EMx catalyst requires replacement periodically.

STEP TWO: Eliminate Technically Infeasible Options

After identifying the potential control technologies that may be available to reduce NO_2 emissions, the Air District then evaluated whether each of them is technically feasible for this project.

Combustion Controls

Both steam/water injection and dry low-NOx combustors are available technologies and have been utilized in many combustion turbine applications. Steam/water injection is not appropriate for use with the heat recovery turbine duct burners, as noted above. Low-NOx burners are the only combustion control technology available for the duct burners.

Catalytic combustors such as XONON™ have not been demonstrated on large-scale utility gas turbines such as the Siemens 501F. The technology has been successfully demonstrated in a 1.5 megawatt simple-cycle pilot facility, and it is commercially available for turbines rated up to 10 megawatts, but it is not currently available for turbines of the size proposed for the Russell City Energy Center.[12]

Post-Combustion Controls

Selective Catalytic Reduction (SCR) with ammonia injection is a proven post-combustion NOx control technique widely used on numerous utility-scale gas turbines/HRSGs. These systems are commercially available from several vendors.

Selective non-catalytic reduction (SNCR) requires a temperature window that is higher than the exhaust temperatures from utility combustion turbine installations. Therefore, SNCR is not technically feasible for this project.

EMx™ has been successfully demonstrated on several small combustion turbine projects up to 45 megawatts, and the manufacturer has claimed that it can be effectively scaled up and made available for utility-scale turbines.[13] Based on this information, it would not be appropriate to eliminate EMx™ as a technically feasible control technology at this stage.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

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[12] Kawasaki Heavy Industries purchased the XONON™ catalytic combustion technology from Catalytica Energy Systems in 2006. Kawasaki plans to use the XONON™ on its own turbines, but it is not known if Kawasaki will make the combustors available to other turbine manufacturers.

[13] S. DeCicco, T. Girdlestone, J.A. Cole, *High Performance EMx™ Technology For Fine Particles, NOx, CO, and VOCs From Gas Turbines and Stationary IC Engines*, April 27, 2006.

Next, the Air District evaluated each of the feasible control technologies and ranked them in order of effectiveness at reducing NO_2 emissions.

For the combustion controls, Dry Low-NOx burners used with Low-NOx duct burners can feasibly achieve NOx emissions as low as 9 ppm.[14] Water/steam injection in the combustion turbines used in conjunction with Low-NOx duct burners can achieve NOx emissions as low as 25 ppm.[15] The Air District therefore ranks Dry Low-NOx Combustors/Low-NOx Duct Burners as the No. 1 control technology; and water/steam injection with Low-NOx Duct Burners as the No. 2 control technology.

For the post-combustion controls, both SCR and EMx™ are equally effective and can achieve a NOx emissions concentration of 2 ppm @15% O2 averaged over one hour.[16] Both technologies therefore share the top ranking.

STEP FOUR: Evaluate the most effective controls and document results

Combustion Controls

The Air District has found no adverse economic, energy, or collateral environmental impacts that counsel against using the most effective control technology, Low-NOx burner technology. The Air District is therefore proposing the use of Dry Low-NOx combustors for gas turbines and Low-NOx burners for the heat recovery boilers as BACT. Selection of the most effective control technology in the hierarchy ends the Top-Down BACT analysis for combustion controls.

Post-Combustion Controls

For the post-combustion controls, the top two technologies, Selective Catalytic Reduction (SCR) and EMx™, are equally effective and share the No. 1 ranking. The Air District has found that both technologies would involve certain economic, environmental, and energy impacts, and has therefore evaluated both technologies to determine whether these impacts suggest that either technology should be eliminated as BACT. The Air District has concluded that neither alternative should be eliminated as an appropriate BACT alternative.

Economic Impacts

The Air District evaluated the cost of each control technology compared with the emissions reductions it can achieve. The Air District determined that both technologies can achieve NO_2 emission reductions of 739.1 tons per year,[17] but that EMx will cost approximately $5,200,000 per

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[14] R. Peltier, *Gas turbine combustors drive emissions toward nil*, Power, March 2003.
[15] B. Bueker, *Basics of Boiler and HRSG Design*, PennWell, 2002, pp 133-135.
[16] S. DeCicco, T. Girdlestone, J.A. Cole, *High Performance EMx™ Technology For Fine Particles, NOx, CO, and VOCs From Gas Turbines and Stationary IC Engines*, April 27, 2006.
[17] The emissions reductions are based upon uncontrolled NO_x emission rate of 25 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr.

year, more than the $2,350,000 approximate annual cost of SCR.[18] This analysis is based on a single GE Frame 7FA gas turbine of an equivalent capacity to the Siemens F5000, equipped with a Dry-Low NOx combustor achieving an NO_x emission rate of 25 ppmvd @ 15% O_2.[19]

Collateral Environmental Impacts

<u>SCR:</u>

The use of SCR will result in ammonia emissions because some of the ammonia used in the reaction to convert NOx to nitrogen and water does not get reacted and remains in the exhaust stream. These ammonia emissions are known as "ammonia slip". Ammonia is a toxic chemical that can irritate or burn the skin, eyes, nose, and throat. The Air District has conducted a health risk assessment using air dispersion modeling to evaluate the potential health impacts of all toxics emissions from the facility, including ammonia slip. This assessment showed an acute hazard index of 0.024 and a chronic hazard index of 0.007. (*See* Health Risk Assessment, Appendix B.) A hazard index under 1.0 is considered less than significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia in a 29.4% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored on-site in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. This risk will be addressed in a number of ways under safety regulations and sound industry safety codes and standards, including the implementation of a Risk Management Program to prevent and respond to accidental releases. Moreover, the CEC has modeled the health impacts arising from a catastrophic ammonia release and has found that the impacts would not be significant.[20] The potential environmental impact from aqueous ammonia transportation and storage does not justify the elimination of SCR as a control alternative.

The Air District also evaluated the potential for ammonia slip emissions to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. Moreover, the Air District has found that the formation of ammonium nitrate in the Bay Area air basin appears to be constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere, a condition known as being "nitric acid

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[18] EPA's NSR Workshop Manual provides that both average cost-effectiveness and incremental cost effectiveness should be considered in the BACT analysis. Since both technologies can achieve the same level of emission reductions, there is no incremental cost effectiveness to evaluate, as neither technology is incrementally better than the other.

[19] The annualized SCR cost figures are based on a cost analysis conducted by ONSITE SYCOM Energy Corporation, updated and adjusted for inflation by the District. These total 1999 annualized cost for SCR was adjusted for inflation by the District using the Consumer Price Index (2008 value = 1999 value x 1.32). Emerachem provided the updated cost information for the EMx.

[20] California Energy Commission (CEC), 2002a. Final Staff Assessment (FSA) and Addendum, published on June 2002. California Energy Commission (CEC) Final Staff Assessment (FSA) Part 1 and Part 2, Section 4.4, Hazardous Materials Management, published on June 2007.

limited".[21] Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with. Therefore, ammonia emissions from the SCR system are not expected to contribute significantly to the formation of secondary particulate matter. Any potential for secondary particulate matter formation is at most speculative, and would not provide a reason to eliminate SCR as a control alternative.

<u>EMx</u>

The use of EMx will require approximately 360,000 gallons of water per year for catalyst cleaning. EMx will also require the use of natural gas for catalyst regeneration. SCR will not have these impacts as the SCR catalyst does not normally require periodic cleaning and regeneration. These environmental impacts do not justify the elimination of EMx as a control alternative.

Energy Impacts

SCR and EMx will both reduce the energy efficiency of the gas turbine/heat recovery boiler power generation trains. These post-combustion controls reduce the energy output per unit of fuel because ancillary equipment such as pumps and control systems require power produced by the plant that would otherwise have gone to the electric grid. In addition, the catalyst beds in both systems are obstructions that create a pressure drop in the exhaust flow across the bed, which requires the combustion turbines to fire additional fuel to increase the exhaust pressure to overcome this back-pressure. Both of these systems will therefore increase fuel consumption per unit of power output. This energy loss will be approximately 67,900 million BTU per year if SCR is used. For EMx, the energy loss will be nearly twice that, approximately 122,000 million BTU per year for the EMx.[22]

Conclusions

Both SCR and EMx would be appropriate BACT post-combustion control alternatives for reducing NO_2 emissions. Both would have the potential for adverse economic, environmental or energy impacts, but none of these impacts would be significant enough to eliminate either of the technologies as BACT. The comparison between these impacts is summarized in Table 9 below.

Table 9: Summary of Collateral Impact Comparison – SCR vs. EMx

Control Alternative	Emission Reductions	Annualized Cost	Cost Effective-ness	Significant Toxics Impacts?	Other Significant Envt'l Impacts?	Energy Impacts
EMx	739.1 tons/yr	$5,265,241	$7,124/ton	No	No	122,000 MMBtu/yr
SCR	739.1 tons/yr	$2,348,898	$3,178/ton	No	No	67,900 MMBtu/yr

<u>STEP FIVE: Select the BACT technology</u>

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[21] BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel, "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997.

[22] *See* "Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000.

As both SCR and EMx™ are equally effective in reducing NOx emissions and are ranked No. 1 in the post-combustion control hierarchy, and neither has significant energy, economic, or environmental impacts that would eliminate it as a BACT alternative, the Air District would consider either as BACT for this project. The applicant has proposed SCR as the post-combustion control, and the Air District therefore adopts this technology as the BACT alternative. As noted above, the Air District has selected low-NOx burner technology for the BACT combustion controls. Together, these technologies represent the Best Available Control Technologies for reducing NO_2 from the combustion turbines/heat recovery boilers.

Determination of BACT emissions limit for NO_2

The Air District also reviewed the NOx emissions limits of other large combined-cycle power plants using SCR systems. These facilities are subject to NOx limits as set forth in the tables below.

Table 10:
NOx Emission Limits for Large Combined-Cycle Power Plants using SCR

Facility	NOx (ppmvd@15%O2)
Hanging Rock, OH-0252	3 (3-hr)
Three Mountain, Shasta County	2.5 (1-hr)
Calpine Facility, Feather River AQMD	2.5 (1-hr)
La Paloma, SJVAPCD	2.5 (1-hr)
Elk Hills, SJVAPCD	2.5 (1-hr)
BP Cherry Point, WA-0328	2.5 (3-hr)
Metcalf Energy Center	2.5 (1-hr)
SMUD Clay Station, SMAQMD	2 (1-hr)
IDC Bellingham, MA	2.0/1.5 (1-hr)
Magnolia Power Project	2 (3-hr)
Magnolia, SCAQMD	2 (3-hr)
Palomar Energy Project	2 (1-hr)
Sacramento Municipal Utilities District, Consumnes	2 (1-hr)
Sunset Power, SJVAPCD	2 (1-hr)
Morro Bay – Duke	2 (1-hr)
Wellton Mohawk, AZ-0047	2 (3-hr)
FPL Turkey Point, FL-0263	2 (24-hr)
Wanapa Energy Center, OR-0041	2 (3-hr)
CPV Warren, VA-0308	2 (1-hr)
Colusa Generating Station	2 (1-hr)

As the table shows, emissions of 2.0 ppm NOx averaged over 1 hour is the most stringent performance standard that has been determined to be achievable at any similar facility using SCR for

NOx control.[23] Based on NOx emissions limits at similar facilities as shown in Table 10 above, the Air District is proposing 2.0 ppm, averaged over 1 hour, as the BACT emission limit for NOx. The Air District is also proposing corresponding hourly, daily and annual mass emissions limits based on the size of the facility. Compliance will be measured on a continuous basis using a Continuous Emissions Monitor.

2. Best Available Control Technology for Carbon Monoxide (CO)

This Section covers the Top-Down BACT analysis for carbon monoxide emissions from the gas turbine/heat recovery steam generator (HRSG) power generation trains.

STEP ONE: Identify Control Technologies

As with NO_2, the Air District has examined both combustion controls to reduce the amount of Carbon Monoxide generated and post-combustion controls to remove Carbon Monoxide from the exhaust stream.

Combustion Controls

Carbon Monoxide is formed by incomplete combustion. Incomplete combustion occurs when there is not enough air to fully combust the fuel, and when the air and fuel are not properly mixed due to poor combustor tuning. Maximizing complete combustion by ensuring an adequate air/fuel mixture with good mixing will reduce Carbon Monoxide emissions by preventing its formation in the first place.

Increasing combustion temperatures can also promote complete combustion, but doing so will increase NO_x emissions due to thermal NO_x formation as described in the previous section. The Air District prioritizes NOx control over Carbon Monoxide control because the Bay Area is not in compliance with the federal standards for ozone, which is formed by NOx emissions reacting with other pollutants in the atmosphere. The Air District therefore does not favor increasing combustion temperatures to control Carbon Monoxide. Instead, the Air District favors approaches that reduce NOx to the lowest achievable rate and then optimize Carbon Monoxide emissions for that level of NOx emissions.

Good Combustion Practices: The Air District has identified good combustion practices as an available combustion control technology for minimizing Carbon Monoxide formation during combustion. Good combustion practices utilize "lean combustion" – large amount of excess air – to produce a cooler flame temperature to minimize NO_x formation, while still ensuring good air/fuel mixing with excess air to

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[23] One facility, the IDC Bellingham facility in Massachusetts, was permitted with a two-tiered NOx emissions limit that required the facility to maintain emissions below 1.5 ppm during normal operations but allowed emissions of up to 2.0 ppm as an absolute not-to-exceed limit. (Note that the facility was never built.) This two-tiered limit recognized that emissions can be highly variable depending on operating circumstances, and will have relatively lower emissions at some times and relatively higher emissions at other times. The proposed Russell City project is expected to exhibit the same type of variation in emissions under the various operating scenarios it will face, and will have emissions as high as 2.0 under some circumstances. The Air District is therefore proposing a 2.0 ppm limit to ensure that the limit will be achievable under all operating conditions.

achieve complete combustion, thus minimizing CO emissions. These good combustion practices can be used with the low-NOx combustion technologies selected for minimizing NOx emissions (Dry Low-NO_x Combustors and Low-NO_x duct burners for the heat recovery boilers).

Post-Combustion Controls

The Air District has also identified two post-combustion technologies to remove Carbon Monoxide from the exhaust stream.

Oxidation Catalysts: An oxidation catalyst oxidizes the Carbon Monoxide in the exhaust gases to form CO_2. Oxidation catalysts are a proven post-combustion control technology widely in use on large gas turbine/HRSGs to abate CO and POC emissions.

EMx™: EMx, described above in the NO_2 discussion, is a multimedia control technology that abates CO and POC emissions as well as NO_x. EMx™ technology uses a catalyst to oxidize Carbon Monoxide emissions to form CO_2, and is therefore also an oxidation catalyst. However, it is not a stand-alone oxidation catalyst since the EMx is also a NOx reduction device. Hence, it is identified as a device separate from the oxidation catalyst.

STEP TWO: Eliminate Technically Infeasible Options

Good combustion practice is a feasible control technique for the gas turbines and duct burners in the heat recovery boiler.

Both EMx™ and Oxidation Catalyst technology are technically feasible options for eliminating Carbon Monoxide from the post-combustion exhaust stream. EMx™ has been demonstrated on a 45 MW Alstom GTX 100 gas turbine at the Redding Electric Municipal Plant in Redding, CA. Oxidation catalysts are installed at numerous similar facilities throughout the state.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

Combustion Controls

Good combustion practice is the only combustion technology identified for reducing the formation of Carbon Monoxide during combustion, and so it is ranked No. 1.

Post-Combustion Controls

The Air District considers EMx and the use of an Oxidation Catalyst to be equivalent technologies for CO post combustion control. Both EMx™ and Oxidation Catalyst are capable of maintaining Carbon Monoxide in the range of 2-4 ppmvd @15% O_2 (3-hour average), depending on load and combustor tuning (as emissions from the combustion turbines/heat recovery boilers vary greatly depending on these factors).[24] The Air District ranks both of these post-combustion control technologies equally as No. 1 for control effectiveness.

STEP FOUR: Evaluate Most Effective Controls and Document Results

Good Combustion Practice

The Air District selects the top combustion control technology, good combustion practice, as the BACT combustion control technology. The Air District has not identified any collateral environmental or other impacts that would suggest that this choice is not appropriate as BACT. Thus, no further top-down analysis is required.

Post-Combustion Controls

EMx and Oxidation Catalyst technologies are expected to have similar energy and environmental impacts. The use of either an Oxidation Catalyst or EMx will require replacing the catalyst bed after a number of years in service. The waste catalyst would need to be disposed of in accordance with applicable local, state and federal regulations regarding waste and hazardous waste disposal. These impacts do not justify eliminating either control technology as a BACT alternative. The Air District would therefore be willing to accept either alternative as BACT. As both alternatives are ranked equally as the No. 1 most effective alternative and have no collateral impacts that would rule them out as an appropriate BACT selection, the choice of either would not require further top-down BACT analysis.

STEP FIVE: Select BACT

As noted above, the choice of post-combustion control technology for Carbon Monoxide is influenced by the choice for NOx. The Air District prioritizes NOx control over Carbon Monoxide control because the Bay Area is not in compliance with the federal standards for ozone, which is formed by NOx emissions reacting with other pollutants in the atmosphere, but is in compliance with applicable standards for Carbon Monoxide. The Air District therefore addresses NOx controls first, and then optimizes Carbon Monoxide controls for the control strategy adopted for NOx.

For this project, the Air District has determined that the choice of SCR and not EMx is appropriate for the BACT control strategy for NOx, as described above. The Air District will therefore not require EMx as the control technology for Carbon Monoxide either. This determination is consistent with the BACT goal of requiring the most effective control technology available, as the Oxidation Catalyst alternative was ranked No. 1 as the most effective option, equally with EMx.

Based on the foregoing analysis, the Air District selects the combination of good combustion practices to reduce Carbon Monoxide during combustion and an Oxidation Catalyst to remove Carbon Monoxide from the exhaust stream as BACT.

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[24] S. DeCicco, T. Girdlestone, J.A. Cole, *High Performance EMx™ Technology For Fine Particles, NOx, CO, and VOCs From Gas Turbines and Stationary IC Engines*, April 27, 2006. Oxidation catalysts have met these BACT permit limits at numerous similar facilities throughout the state. In addition, the District has reviewed Continuous Emissions Monitoring (CEM) data and source test data from a similar facility using an Oxidation Catalyst to abate CO emissions.

Determination of BACT Emissions Limit for Carbon Monoxide (CO):

To establish a BACT permit limit for Carbon Monoxide, the Air District reviewed Continuous Emission Monitor Summary data from a similar facility for the period from August 2005 until August 2008.[25] Like the proposed Russell City project, this facility uses Siemens F-Class turbines and is abated by SCR units and Oxidation Catalysts. The facility was able to maintain Carbon Monoxide emissions below 2 ppmvd @15%O_2 throughout much of this period, although on a significant number of occasions emissions rose towards 4 ppm @15%O_2 or even higher. These periods of higher emissions were likely the result of low-load or transient load conditions. Gas turbines are typically optimized for full load operation. At partial loads, the combustion efficiency decreases and the firing temperature drops (resulting in incomplete burnout of Carbon Monoxide). When the gas turbine is in transition, the fuel/air ratio is adjusting to the changing firing rate (as fuel lags combustion air flow during a load increase and the combustion air lags fuel flow during a load decrease) resulting in lower combustion efficiency. For the periods where Carbon Monoxide exceeded 4 ppm, the majority (10 of 13) occurred during the first 12 months of operation, indicating that these higher emissions levels were most likely the result of the facility fine-tuning the equipment and optimizing its operating procedures. There were relatively fewer days where emissions exceeded 4 ppm after the first 12 months of operation, indicating that the equipment should be able to keep emissions down to that level on an ongoing basis.

Based on this data, the Air District has concluded that the selected BACT technology should be able to achieve Carbon Monoxide emission rates as low as 2 ppm during some operations, but under some conditions (*e.g.* transient load conditions) will have emission rates up to 4 ppm. The appropriate BACT emissions limit for this equipment is therefore 4.0 ppmvd @15%O_2.

The Air District has also reviewed a number of similar combined-cycle power plants using similar equipment to further evaluate what Carbon Monoxide emissions limit would be achievable for this choice of BACT technology. A summary of the facilities reviewed is set forth in Table 11 below. The table identifies both NOx limits and Carbon Monoxide limits because they are dependent on each other. The lower the NOx limit, the greater leeway must be given in the Carbon Monoxide limit because reducing NOx normally results in increasing Carbon Monoxide.

Table 11:
Recent BACT carbon monoxide permit limits for large combined-cycle combustion Turbines/heat recovery boilers

Facility	NOx ppmvd @15%O2	CO ppmvd @15%O2	Operational Status
Hanging Rock, OH-0252	3 (3-hr)	9 (24-hr)	Unknown
FPL Turkey Point, FL-0263	2 (24-hr)	8 (24-hr)	Unknown
La Paloma, SJVAPCD	2.5 (1-hr)	6 (3-hr)	In Operation

[25] See Metcalf Energy Monthly BAAQMD CEM Reports, from 5/1/2005 to 1/31/2008. The Air District focused on data from days without startup or shutdown activity. When the turbines/heat recovery boilers are starting up or shutting down, Carbon Monoxide emissions are much higher than during steady-state operations as discussed in more detail in subsequent sections. By looking only at data from days without startups or shutdowns, the Air District has ensured that the limit it adopts will be appropriate for steady-state operating conditions.

Table 11: Recent BACT carbon monoxide permit limits for large combined-cycle combustion Turbines/heat recovery boilers			
Facility	**NOx ppmvd @15%O2**	**CO ppmvd @15%O2**	**Operational Status**
Mountainview San Bernadino County	2.5 (1-hr) 2.0 (1-hr) in 2005	6 (3-hr)	In Operation
Three Mountain, Shasta County	2.5 (1-hr)	4 (3-hr)	Not Built
SMUD Clay Station, SMAQMD	2 (1-hr)	4 (3-hr)	Unknown
Elk Hills, SJVAPCD	2.5 (1-hr)	4 (3-hr)	In Operation
Sunset Power, SJVAPCD	2 (1-hr)	4 (3-hr)	Unknown
Palomar Energy Project	2 (1-hr)	4 (3-hr)	In Operation
Sacramento Municipal Utilities District, Consumnes	2 (1-hr)	4 (3-hr)	In Operation
San Joaquin Valley Energy Center	2 (1-hr)	4 (3-hr)	Not Built
Calpine Facility Sutter, Feather River AQMD	2.5 (1-hr)	4 (24-hr)	In Operation
Sierra Pacific Power Company, Tracy Station, NV-0035	2 (3-hr)	3.5 (3-hr)	Unknown
ANP Blackstone, MA-0024	2 (1-hr) No Steam 3.5 (1-hr) Steam Inj.	3.0 (1-hr)	In Operation
Welton Mohawk, AZ-0047	2 (3-hr)	3 (3-hr)	Unknown
Colusa Generating Station	2 (1-hr)	3 (3-hr)	Not Built
Rocky Mountain Energy Center, CO-0056	3.0 (1-hr)	3	In Operation
Turner Energy Center, OR-0046	2.0 (1-hr)	2.0 (3-hr)>70% load, 3.0 (3-hr)<70% load	Not Built
Berrian Energy Center, MI-0366	2.5 (24-hr)	2.0 (3-hr)	Unknown
BP Cherry Point, WA-0328	2.5 (3-hr)	2 (3-hr)	Unknown
Wanapa Energy Center, OR-0041	2 (3-hr)	2 (3-hr)	Not Built
Morro Bay - Duke	2 (1-hr)	2 (3-hr)	Not Built
Goldendale Energy, WA-0302	2 (3-hr)	2 (1-hr)	In Operation
Sumas Energy 2, WA-0315	2 (3-hr)	2 (1-hr)	Not Built
IDC Bellingham, MA	1.5 (1-hr)	2 (1-hr)	Not Built
Magnolia, SCAQMD	2 (3-hr)	2 (1-hr)	In Operation
Southern Company McDonough Combined Cycle, GA-0127	6 (May thru Sept) 15, 30 day Rolling Avg.	1.8 (3-hr)	In Operation
CPV Warren, VA-0308	2 (1-hr)	1.2 to 2.5 (3-hr)	Not Built

Notes: Limits are with duct burners in operation. All projects use gas turbines equipped with Dry Low NO_x combustors. All projects use GE Frame 7FA turbines except Feather River (Siemens 501F), San Joaquin Energy Center (Siemens 501F), ANP Blackstone (ABB GT-24), and La Paloma (ABB GT-24). SCR was utilized for NO_x control at all facilities. Oxidation Catalyst was utilized for CO and POC control at all facilities except Turkey Point., and Hanging Rock.

This review shows that many similar facilities have been permitted with Carbon Monoxide limits of 4.0 ppm, although there are also several facilities that have been permitted with lower limits in the range of 2-3 ppm or even less. Based on all of the evidence that the Air District has reviewed, a limit in the 2-3 ppm range used in some of these permits may not be achievable for the proposed Russell City Energy Center.

First, many of the facilities with very low Carbon Monoxide limits have less stringent NOx limits that the Air District is proposing here. Some of these facilities are allowed to emit NOx at a higher concentration than the 2.0 ppm limit proposed here. Others are allowed to average their emissions over a longer period of time, which allows the facility to exceed the stated numerical limit for a period of time as long as the excess emissions are offset by lower emissions at other times during the averaging period. The Air District is proposing a stringent one-hour averaging period, which together with the 2.0 ppm numerical limit is the most stringent NOx emission limitation of any similar facility that the Air District has identified, as discussed in the previous section.[26] This stringent NOx limit requires some additional flexibility in the Carbon Monoxide limit given the trade-off between NOx reductions and Carbon Monoxide reductions. The more stringent NO_x limit proposed for the Russell City Energy Center makes achieving a 2 ppmvd Carbon Monoxide limit much more difficult.

Second, for the other facilities that have been permitted with a 2.0 ppm NOx limit and a one-hour NOx averaging period, there is little evidence that the facilities would be able to achieve a permit limit of less than 4.0 ppm at low loads and under rapidly-changing load conditions (as explained earlier these operating conditions cause CO emissions to increase). The majority of such facilities with CO permit limits below 4.0 ppm have not been built yet and so there is no operational data on which to evaluate their actual performance under the types of operating scenarios expected for the Russell City Energy Center. Moreover, the BACT determinations that the Air District has reviewed for these facilities do not cite actual data showing that the lower limits are achievable.[27] In light of the evidence showing that emissions will reasonably be expected to be up to 4.0 ppm under some conditions, and without any actual data establishing that a lower limit can consistently be maintained, there is no basis for establishing a BACT limit of less than 4.0 ppm for this facility.

For these reasons, the available data shows that the lowest emissions that these turbines can reasonably achieve using good combustion practices with an oxidation catalyst is 4.0 ppm @15%O_2 (3-hour average). The Air District is therefore proposing this limit as BACT, along with corresponding hourly, daily and annual mass emissions limits. Compliance with these limits will be verified by a continuous emission monitor (CEM) located at the common stack for each gas turbine/heat recovery boiler power train.

3. Best Available Control Technology for Particulate Matter (PM)

[26] As discussed above, the Air District prioritizes NOx over Carbon Monoxide because given the current state of air pollution in the Bay Area, it is more important to reduce NOx emissions in order to address regional ozone pollution (smog) than to address Carbon Monoxide.

[27] *See, e.g.*, Ambient Air Quality Impact Report, Colusa Generating Station, US EPA Region 9 PSD Permit No. SAC 06-01 (May 2008), p. 17.

This Section covers the top-down BACT analysis for Particulate Matter emissions from the combustion turbine/heat recovery boiler power generation trains.

Particulate Matter emissions from this equipment result from several processes. Particulate Matter may be entrained in the combustion air that passes through the combustor inlet filter, and any such Particulate Matter will pass through the combustion chamber and out into the exhaust stream. Trace amounts of Particulate Matter may also be entrained in the natural gas and will also end up in the exhaust stream. In addition, sulfur in the natural gas can form Particulate Matter during combustion, and can also combine with other compounds in the atmosphere after it is emitted to form "secondary" Particulate Matter such as sulfates. Finally, some hydrocarbons in the natural gas may not be fully combusted and may condense to form Particulate Matter. Particulate emissions can vary greatly among different combustion turbines based on factors such as the combustion characteristics of the turbine, the sulfur and particulate content of the natural gas being burned, and the amount of particulates entrained in the combustion air.

STEP ONE: Identify Control Technologies

As with the other pollutants addressed above, control technologies for Particulate Matter can be grouped into two categories: (1) combustion controls, and (2) post-combustion controls.

Combustion Controls

Good Combustion Practice: The Air District has identified good combustion practices as an available combustion control technology for minimizing unburned hydrocarbon formation during combustion. Good combustion will ensure proper air/fuel mixing to achieve complete combustion, thus minimizing emissions of unburned hydrocarbons that can lead to formation of Particulate Matter at the stack.

Clean-burning fuels: The use of clean-burning fuels, such as natural gas that has only trace amounts of sulfur that can form particulates, will result in minimal formation of Particulate Matter during combustion.

Dry Low-NOx Combustor: The use of a Dry Low-NOx Combustor provides efficient combustion to ensure complete combustion thereby minimizing the emissions of unburned fuel that can form condensable Particulate Matter.

Post-Combustion Controls

Electrostatic precipitators: Electrostatic precipitators are used on solid fuel boilers and incinerators to remove Particulate Matter from the exhaust. Electrostatic precipitators use a high-voltage direct-current corona to electrically charge particles in the gas stream. The suspended particles are attracted to collecting electrodes and deposited on collection plates. Particles are collected and disposed of by mechanically rapping the electrodes and plates and dislodging the particles into collection hoppers.

Baghouses: Baghouses are used to collect particulate matter by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags which are periodically shaken to release the particulates into hoppers.

STEP TWO: Eliminate Technically Infeasible Options

Good combustion practice is a feasible control technique for the gas turbines and duct burners in the heat recovery boiler.

The use of natural gas as fuel in a Dry Low-NOx combustor is commercially available and demonstrated for the Russell City Energy Center gas turbines and heat recovery boilers. Low-sulfur natural gas is readily available as a fuel, and Dry Low-NOx combustors are commercially available for this type of application.

Electrostatic precipitators and baghouse systems are not feasible for natural gas-fired combustion turbines and related equipment, however, because they generate a significant backpressure on the exhaust stream. This backpressure would necessitate the use of additional forced draft fans to blow the hot exhaust gases through the particulate control device and out the stack. The additional air introduced into the exhaust stream by such fans would further dilute the particulate concentration in the exhaust stream to such a low level that fabric filters and electrostatic precipitators would be ineffective.[28] Post-combustion particulate control equipment therefore is not feasible for the RCEC turbines.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

Low-sulfur natural gas and Dry Low-NOx combustors with Good Combustion Practice are the only feasible control technologies. They can be used in combination with each other, and so they are all ranked No. 1 in terms of control effectiveness. The Air District has determined that the use of these control technologies represents the Best Available Control Technology for Particulate Matter. There are no collateral adverse impacts that would call into question the selection of these technologies as BACT. Because the Air District has chosen the top-ranked control technologies, no further analysis is required under EPA's top-down BACT approach.

Determination of BACT Emissions Limit for Particulate Matter:

For low-sulfur fuel, the highest quality commercially available natural gas is natural gas that meets the California PUC regulatory standard of less than 1.0 grains of sulfur per 100 scf. This PUC standard is maximum sulfur content at any point in time; the actual average content is expected to be less than 0.25 grains per 100 scf. The Air District is therefore proposing a BACT limit for fuel sulfur content of 1.0 grains of sulfur per 100 scf, and 0.25 grains per 100 scf averaged over any 12-month period.

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[28] 0.0013 to 0.01 grains per standard cubic foot. *BAAQMD BACT/TBACT Workbook*, Section 11: Miscellaneous Sources.

The Air District is also proposing a numerical BACT emissions limit for Particulate Matter emissions. The District is proposing a BACT limit of 9 pounds per hour as the lowest reasonably achievable emissions limit based on operating experience and source test results at other plants with similar equipment owned and operated by the applicant. The Particulate Matter emission rate of 9 pounds per hour is equivalent to 0.0040 pounds per million BTUs, 430 pound per day (both trains), and 0.0030 grains per dry standard cubic foot (3% O2).

In establishing this limit, the Air District also looked at the performance of other similar facilities using similar types of equipment and fuel as demonstrated by enforceable permit conditions imposed as BACT limits. The table below presents Particulate Matter BACT limits for projects similar to the proposed Russell City Project.

Table 12:
Recent BACT PM_{10} Permit Limits for large combined-cycle combustion Turbines/heat recovery boilers

Facility	Without Duct Firing		With Duct Firing	
	PM_{10} Emissions Limit	PM_{10} (lb/MMBtu)	PM_{10} Emissions Limit	PM_{10} (lb/MMBtu)
Wellton Mohawk, AZ-0047			29.8 lb/hr GE 33.1 lb/hr Siemens	
Hanging Rock, OH-0252	15 lb/hr		23.3 lb/hr	
Goldendale Energy Project, WA-0302	19 lb/hr Base Load		22.3 lb/hr Peak	
ANP Blackstone, MA-0024	21.8 lb/hr	0.012	NA	
Colusa Generating Station	20.1 lb/hr	0.0088	20.1 lb/hr	0.0088
Berrian Energy Center, MI-0366	19 lb/hr	0.012	28.9 lb/hr	0.013
La Paloma, SJVAPCD			17.2 lb/hr	
Palomar Energy Project	14 lb/hr		14 lb/hr	
Morro Bay - Duke			13.3 lb/hr	0.0058
Calpine Facility Sutter, Feather River AQMD	9.0 lb/hr	0.0047	11.5 lb/hr	0.0056
San Joaquin Valley Energy Center	9.0 lb/hr		11.5 lb/hr	
CPV Warren, VA-0308	9.9 lb/hr 12.5 lb/hr	0.0045 0.0064	11.3 lb/hr Siemens 17.56 GE	0.0047 0.0072
Mountainview San Bernardino County			11.0 lb/hr	0.0052
SMUD Clay Station, SMAQMD			9 lb/hr	
Sacramento Municipal Utilities District, Consumnes	9.0 lb/hr	0.00483	NA	NA
Metcalf Energy Center, BAAQMD			9.0	0.00452
Delta Energy Center,			9.0	0.00424

Table 12: Recent BACT PM_{10} Permit Limits for large combined-cycle combustion Turbines/heat recovery boilers				
Facility	Without Duct Firing		With Duct Firing	
	PM_{10} Emissions Limit	PM_{10} (lb/MMBtu)	PM_{10} Emissions Limit	PM_{10} (lb/MMBtu)
BAAQMD				
Los Medanos Energy Center, BAAQMD			9.0	0.0040
Sumas Energy 2, WA-0315			571 lb/day total	
Sierra Pacific Power Company, Tracy Station, NV-0035			0.011 lb/MMBtu	
IDC Bellingham, MA			0.008 lb/MMBtu	
Rocky Mountain Energy Center			0.0074 lb/MMBtu	
Three Mountain, Shasta County			0.0012 gr/dscf@ 3% O_2	
Magnolia, SCAQMD			0.01 gr/dscf	

Notes: 1. Limits are with duct burners in operation except for SMUD Consumnes and ANP Blackstone which have unfired HRSGs.
2. SCR for NO_x at all facilities.
3. All projects use turbines equipped with Dry Low NO_x combustors.
4. Oxidation Catalyst for CO and POC are utilized at all facilities except Turkey Point, Hanging Rock and Delta Energy Center.

The proposed Particulate Matter emissions limits are as low or lower than the emissions requirements in the table above for similar power plants, except the Three Mountain Power Plants (0.0012 gr/dscf@ 3% O_2). This plant was never built so it is not possible to determine whether it was able to meet the respective Particulate Matter requirement.

4. Best Available Control Technology For Gas Turbine Startups, Shutdowns, and Tuning

Startup and shutdown periods are a normal part of the operation of combined-cycle natural gas-fired power plants. They involve emissions rates that are greater than emissions during steady state operation and are highly variable. Emissions are greater during startup and shutdown for several reasons. One reason is that during startup and shutdown, the turbines are not operating at full load where they are most efficient. Another reason is that the exhaust temperatures are lower than during steady-state operations. Post-combustion emissions control systems such as the SCR catalyst and oxidation catalyst do not function optimally at lower temperatures, and so there may be partial or no abatement for NO_x and Carbon Monoxide for a portion of the startup period.[29]

[29] Note that emission rates of Particulate Matter are not affected by startups and shutdowns and will be the same as for full load operation as during startup and shutdown periods (9 lb/hour for Particulate Matter).

For startups, the duration of the startup depends upon the temperature of the equipment at the beginning of the startup period. Equipment that is already warm will be able to come up to its full operating temperature more quickly than equipment that is started cold. The longest startups occur when the equipment has been down for 3 days or more (a "cold start"), in which case the startup can take up to six hours until the equipment can achieve its steady-state emissions rates. These cold starts are expected to be infrequent, occurring as little as once per year. The majority of startups will occur when the equipment is already warm or hot ("hot starts" and "warm starts"), which will take between 1 and 3 hours for the equipment to come up to its full temperature.

In addition, the facility may need combustor tuning. This is a regular plant equipment maintenance procedure in which testing, adjustment, tuning, and calibration operations are performed, as recommended by the equipment manufacturer, to insure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. The SCR and oxidation catalyst may not be operating during the tuning operation. The proposed facility would be limited to one tuning operation a year.

Because emissions are greater during startups, shutdowns and combustor tuning periods than during steady-state operation, the BACT limits established in the previous sections for steady-state operations are not technically feasible during these periods. As these limits are not "achievable" during these operating modes, they are not "Best Available Control Technology" as defined in the Federal PSD Regulations. Therefore, alternate BACT limits must be specified for these modes of operation. To do so, the Air District has conducted an additional Top-Down BACT analysis specifically for startups, shutdowns, and tuning periods.

STEP ONE: Identify Control Technologies

The Air District has identified three potential strategies to reduce startup and shutdown emissions for the proposed Russell City facility.

Work practices to minimize emissions: By following the plant equipment manufacturers' recommendations, power plant operators can limit the duration of each startup and shutdown to the minimum duration achievable. Plant operators also use their own operational experience with their particular turbines and ancillary equipment to optimize startup and shutdown emissions.

Once-Through Steam Boiler Technology: Conventional combined-cycle power plants use a thick-walled steam drum in the steam generator to contain the steam before it is introduced into the steam turbine. This steam drum is a major impediment to quicker startups, because its thick steel walls need to be heated slowly and gradually to reduce metal fatigue and ensure long-term safety and reliability of the system. Recently, turbine manufacturers have been utilizing "once-through" boiler technology that does not use the conventional steam drum to contain the steam. These once-through designs (and modified drum designs with the operational characteristics of the once-through boiler) use external steam separators and surge bottles, so they can be brought up to temperature more quickly. Reducing the duration of the startup would reduce startup emissions.

Low-Load "Turn-Down" Technology: Another reason why emissions are increased during startups is that the turbine must spend a certain amount of time operating at less efficient lower loads as it is ramped up to full load. Operating at these lower loads leads to increased emissions. One approach that shows potential for addressing this problem is so-called "turn-down" technology that has been developed to enable turbines to operate more cleanly at lower loads for energy conservation purposes. This technology enables a gas turbine to operate in a standby mode (low capacity) that facilitates a quick ramp-up of capacity to meet electrical demand. The technology uses advanced fuel scheduling (an improved method of controlling fuel distribution) to distribute fuel in the combustor for low turndown operation while maintaining low NOx and CO emissions. It was developed to allow facilities to cut back to lower loads when their power is not needed (typically at night) and still maintain compliance with emissions limits. By cutting back to low load without shutting down completely, the facility can be ready to ramp back up and provide power immediately when demand requires (the next morning, for example). In principle, this same approach should be applicable to startup emissions as well: better performance at low load should be able to reduce emissions during the portions of the startup when the turbine is in low-load operation. As explained below, however, turn-down technology has been applied in startup applications only very recently and its use as a startup control technology is still developing.

STEP TWO: Eliminate Technically Infeasible Options

Using **best work practices** to keep startups and shutdowns as short as possible is a feasible way of minimizing emissions during these periods.

Once-Through Boiler Technology is also a technically feasible control technology. Siemens, the manufacturer whose equipment is proposed for the Russell City Energy Center, has developed a once-through design that it uses in what it calls a "Fast Start" system.[30] The proposed facility could implement Siemens Fast Start technology by installing a Siemens "Flex Plant 10" integrated plant using a single-pressure heat recovery boiler and steam turbine.[31] The single-pressure heat recovery boiler is optimized for peaking plants, however, and not for combined-cycle baseload plants such as the proposed Russell City facility. Those facilities normally use a triple-pressure heat recovery boiler and steam turbine, which is more energy efficient. The single-pressure design operates at an efficiency of approximately 48%, whereas the triple-pressure design can achieve an efficiency of approximately 56%, making it nearly 17% more energy efficient. Siemens is working on developing a triple-pressure system using Fast-Start technology, "Flex Plant 30", but it is still under development, and has not yet been proposed for any power plant projects.[32] The only technically feasible once-through technology at this point is the single-pressure design, which is inherently less efficient.

[30] M. McManus, D. Boyce, R. Baumgartner, Siemens Power Generation, Inc., *Integrated Technologies that Enhance Power Plant Operating Flexibility*, POWER-GEN International 2007, December 11-13, 2007.

[31] Note that the project was originally permitted in 2002, before Fast Start technology was developed, and the applicant purchased its equipment at that time based on the initial permits. Retrofitting that equipment now to incorporate Fast Start technology would require a complete redesign of the project and the purchase of new equipment. Furthermore, Siemens stated that emissions performance cannot be guaranteed unless the company supplies a fully integrated power plant with Fast Start technology (*i.e.* Flex Plant 10). (Telephone conference on November 6, 2008 with Candido Veiga, Siemens Pacific Northwest Region Vice President and Benjamin Beaver, Siemens Pacific Northwest Sales Manager.) It therefore appears that the facility would have to dispose of the equipment it has already purchased for the project and buy an entirely new integrated system.

[32] Telephone conference on November 6, 2008 with Candido Veiga, Siemens Pacific Northwest Region Vice President and Benjamin Beaver, Siemens Pacific Northwest Sales Manager.

Turn-Down Technology is a fairly new development in turbine technology, and only very recently have attempts been made to adapt it to reducing startup emissions (as opposed to using it to allow low-load operation). Siemens, whose equipment is being proposed for the Russell City Energy Center, is developing a low-load operation flexibility (LLOF) system for its turbines, but it has not yet been validated and is not commercially available at this time.[33] GE, another turbine manufacturer, has a commercially available turn-down technology which it calls "OpFlex",[34] but the company has only just developed a variant aimed at controlling startup emissions. GE calls this adaptation the "OpFlex™ Start-up NOx Start-up Fuel Heating" package. GE claims that emissions of NOx may be lowered to less than 25 ppm NOx at low load operation (20% to 50% load),[35] and that "start-up times can be reduced by as much as 30 minutes for a cold start, 15 minutes for a warm restart and 5 minutes for a hot restart".[36] These are highly encouraging predictions, but GE is not prepared to guarantee these numbers, or any specific level of emissions reductions, for the product at this time.[37] Without a manufacturer guarantee, the Air District cannot conclude with any certainty that this technology will obtain the predicted reductions. Predictions of potential performance are not, by themselves, sufficient evidence on which to require this technology as BACT.

To make up for the lack of a manufacturer's guarantee, the Air District attempted to develop independent objective support for the technology's feasibility as a startup control alternative. To do so, the Air District looked for actual operating data from facilities using GE's OpFlex turn-down technology as a startup emissions control technology. The Air District was able to identify only one facility that has tried to implement OpFlex to control startup emissions, the Palomar Energy Center ("Palomar") in San Diego County.[38] That facility was required to implement drastic startup emissions reductions under a variance proceeding before the Hearing Board of the local Air District, the San Diego Air Pollution Control District.[39] The facility took several steps in order to do so. One of these was to purchase and install an OpFlex system from GE. Another was to adjust its ammonia injection procedures so that ammonia is injected into the SCR system earlier in the startup than recommended by the manufacturer, when the SCR catalyst is at a lower temperature. The operator conducted tests on its turbines and found that for its particular equipment, earlier ammonia injection was a workable solution. By taking these steps, the facility was able to optimize its operating procedures and bring down its startup emissions. The facility has reported encouraging results from the first few months of operating with these new techniques.[40] It is not possible, however, to

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[33] See P. Nag, D. Little, D. Teehan, K. Wetzl & D. Elwood, Siemens Corporation, *Low Load Operational Flexibility for Siemens G Class Gas Turbines*, to be presented at the Power-Gen International, Orlando, Florida, December, 2008.

[34] GE Fact Sheet for OpFlex™ Turndown, GE Energy website: www.gepower.com.

[35] GE Fact Sheet for OpFlex™ Start-up NOx and Start-up Fuel Heating, GE Energy website: www.gepower.com.

[36] *Gas Turbine Upgrades for Enhancing Operational Flexibility*, EPRI, Palo Alto, CA: 2007, 1012720, at 2-17, available at: http://mydocs.epri.com/docs/public/000000000001012720.pdf.

[37] GE has declined to give emissions performance guarantees for start-up operations using the OpFlex™ software, explaining that startup emissions, by nature, are highly variable and dependent on specific plant equipment and configuration. (Telephone conversations with Bob Bellis and Derrick Owen, GE Energy on November 21, 2008.)

[38] Letter written by Daniel S. Baerman, Director of Electric Generation, San Diego Gas and Electric, regarding "Nonapplicability Confirmation for Installation of Tuning Software". Submitted to Dan Speer, San Diego County Air Pollution Control District, dated August 22, 2006. The Air District found no other facilities other than Palomar using OpFlex to control startup emissions.

[39] *See* San Diego Air Pollution Control District Hearing Board Docket No. 4703.

[40] Letter written by Daniel S. Baerman, Director of Electric Generation, San Diego Gas and Electric, regarding "Hearing Board Variance 4073; Quarterly Report". Submitted to Catherine Santos, Clerk of the Hearing Board for the San Diego County Air Pollution Control District, dated April 11, 2007.

determine based on this limited data what reductions, if any, are attributable to OpFlex and what reductions are attributable to the operational changes the facility was able to make for its specific turbines. Moreover, the facility has operated only for a relatively limited period of time with these enhancements, and so it is difficult to determine from the limited data available so far what improvements can reliably be achieved throughout the life of the facility. For all of these reasons, the Palomar data does not sufficiently demonstrate that there are specific, achievable emissions reductions to be gained simply from using the OpFlex technology itself. Further data will be needed to understand whether some or all of Palomar's proprietary approach for reducing emissions from its equipment can be adapted to other facilities.

Finally, the Air District also looked for other BACT determinations for similar facilities to see whether any other permitting agencies have required OpFlex or similar turn-down technologies to reduce startup emissions. The Air District did not find any BACT determinations where an agency required this type of technology. One permitting agency, EPA Region 9, has considered whether it should be required as BACT, but concluded that it should not.[41]

In summary, the Air District looked to manufacturer guarantees, to actual data from similar facilities, and to permitting actions by other agencies, but has not found sufficiently strong evidence to conclude that turn-down technologies such as OpFlex are technically feasible at this time for control of start-up emissions. While it appears that the technology may have potential for use in reducing startup emissions, the manufacturer cannot guarantee any emissions reductions for such an application. Moreover, OpFlex has been used as a startup control technology at only one facility, and it is not clear whether and to what extent it achieved any reductions, as opposed to other changes the facility made to its proprietary operating procedures for its specific equipment. In addition, EPA has recently determined that the technology is not sufficiently developed as a startup control technology to be required as BACT. For all these reasons, the Air District has concluded that OpFlex and similar low-load turn-down technologies are not technically feasible for use in reducing startup emissions at this time. The Air District will continue to monitor the development of this technology, however, to see whether it may have potential in the future to be required as a mandatory enhancement of power plants' startup emissions control strategies.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

Once-through boiler technology would shorten startup times and reduce startup emissions, and so it is ranked No. 1 in control effectiveness. Siemens stated that the Flex Plant 10 could synchronize to the grid in 5 minutes and produce 150 MW on line in 10 minutes; the combustion turbine can achieve emissions compliance in 12 minutes and stack compliance in 20 minutes.

Best work practices can keep startup times below 3 hours for warm and hot startups, and below 6 hours for cold startups. This alternative is ranked No. 2 in control effectiveness because it would result in longer startup periods and therefore additional startup emissions.

[41] *See* Ambient Air Quality Impact Report, Colusa Generating Station, Clean Air Act PSD Permit No. SAC 06-01, EPA Region 9, May 2008. The record from that permitting action shows that EPA Region 9 considered OpFlex and the Palomar facility in response to a comment on the startup BACT issue. That comment was subsequently withdrawn and so EPA never responded to it formally on the record. But the fact that the agency determined that BACT does not require OpFlex is evident from the fact that the permit does not require it.

STEP FOUR: Evaluate Most Effective Controls and Document Results

To determine whether to require once-through boiler technology as BACT, the Air District evaluated its ancillary economic, environmental and energy impacts.

The primary ancillary impacts arise from decreased energy efficiency. As noted above, the only type of once-through boiler technology that is technically feasible at this time is a single-pressure system, the Siemens Flex Plant 10. Combined-cycle turbines with a steam drum design use a triple-pressure system, meaning that steam is introduce into the steam turbine at three different pressures at different point in the turbine, improving electrical output and enhancing efficiency. Requiring a once-through design would eliminate the possibility of using a triple-pressure system.

To evaluate the adverse impacts of this loss in energy efficiency, the Air District compared emission rates from the proposed Russell City Energy Center with its triple-pressure design to those predicted for a proposed facility using a Flex Plant 10 design.[42] The proposed Russell City project will have an energy efficiency of 55.8%,[43] whereas the Flex Plant 10 design will have an efficiency of only 48%. This loss in efficiency means that the Flex Plant 10 design will need to burn more fuel to produce the same amount of power output, which will generate greater emissions. The difference in emissions per unit of power generated is shown below in Table 13.

Table 13: Comparison of Emissions Per Unit of Power Generated (lb/MW-hr)

	NOx	CO	POC	PM	SO_2	CO_2
Flex Plant 10	0.0609	0.0748	0.0108	0.0359	0.0224	936.75
Triple-Pressure System	0.0517	0.0629	0.0090	0.0298	0.0195	796.47
Emissions Increase:	17.92%	18.91%	20.40%	20.34%	14.76%	17.61%

These emissions increases are a substantial drawback from an environmental perspective. Significantly, they are increased environmental impacts that will occur at all times when the facility is operating, including normal base-load operation. This is an important fact in evaluating the trade-offs from requiring a Flex Plant 10 design to improve startup operation. Startups occur occasionally and any benefits in startup mode will be obtained only during startup, whereas the ancillary environmental impacts will occur during all periods of operation. The loss in energy efficiency is also an adverse energy-related impact, as less energy will be generated from the same amount of fuel. The technology would also have an adverse economic impact due to the cost of increased fuel usage.

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[42] Data for the Flex Plant 10 comparison come from a permit application the Air District has received for a facility proposing to use a Flex Plant 10 design, District Application #18542. The proposed Flex Plant 10 facility will have a heat input capacity of 1857 MMBtu/hr. The District adjusted the proposed Russell City project's emissions numbers proportionally to the capacity difference between the two facilities to achieve an "apples-to-apples" comparison. Calculations assume ISO standard conditions and 59°F. Data for Russell City assume no supplemental duct burner firing, because the proposed Flex Plant 10 does not use duct burners.
[43] *See* Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4.

For all of these reasons, the Air District has eliminated the once-through boiler alternative as an appropriate BACT technology for startup emissions for a facility such as Russell City. The Air District has concluded that the adverse impacts of requiring a single-pressure steam turbine design outweigh the additional startup benefits that can be achieved. The Air District will continue to monitor the development of once-through boiler technologies, in particular the Siemens Flex Plant 30 design using a triple-pressure steam boiler. Such future developments could change the analysis regarding the tradeoffs between overall energy efficiency and startup performance.

In contrast to current once-through boiler designs, best work practices have no adverse economic, energy, or environmental impacts that would rule it out as a BACT control technology. The District selects this alternative as BACT for startup emissions for this proposed project.

STEP FIVE: Select BACT

Based on the foregoing analysis, the Air District has concluded that once-through boiler technology would not be the most appropriate BACT technology because of the loss of efficiency that it would entail. The Air District has therefore eliminated it as a control option, and selects best work practices as BACT for startups, shutdowns and tuning.

Determination of BACT Emissions Limit for Startups, Shutdowns and Tuning Events:

The Air District has concluded that using best work practices, the proposed Russell City Energy Center will be able to limit cold startups to 6 hours in duration, 480 pounds of NO_2 emissions, and 5028 pounds of CO emissions; warm and hot startups to 3 hours in duration, 125 pounds of NO_2 emissions, and 2514 of CO emissions; and shutdowns to 30 minutes in duration, 40 pounds of NO_2 emissions, and 90 pounds of CO emissions. The basis for these limits are the permit limits that were established for the Metcalf Energy Center, the most recent similar facility that the Air District has permitted. The Air District began with those limits as a starting point, and then examined data and permit conditions from other facilities to determine if lower limits could be reasonably achieved by this facility. In some instances, recent experience has shown that more stringent limits than were imposed at Metcalf are appropriate. In other cases, more stringent limits would not be achievable.

Cold Startups

The Air District examined data from a number of other similar facilities to determine if cold startups could achieve less than 6 hours in duration, 480 pounds of NO_2 emissions, and 5028 pounds of CO emissions. The data showed a very large amount of variability, which is caused by a number of reasons. The factors that can make individual startups take longer or shorter and generate more or less emissions include ambient temperatures of the equipment, limitations on the loading sequence prescribed by the gas turbine manufacturer to assure safe loading of the equipment, and limitations on the steam-cycle side of the facility necessary to ensure that the steam turbine and associated piping are safely warmed.

The Air District examined startup data from the Sutter Energy Center, which is located in Yuba City and also uses Siemens/ Westinghouse F-class gas turbines, for the past two calendar years. The data for cold startups are set forth below in Table 14. As the table shows, a number of startups have had

NO_2 emissions close to or even above the proposed 480 pound limit for the Russell City facility. Several of the startups have taken all or nearly all of the full 6 hours proposed for Russell City.

Table 14: Sutter Energy Center Cold Start-Up Event Summary

Date	Unit	Duration (min)	Total NOx (lbs)	Total CO (lbs)
1/8/2007	2	314	399	872
4/16/2007	2	300	385	233
4/23/2007	2	264	328	1034
4/23/2007	1	300	346	415
1/6/2008	1	325.2	480	1454
3/5/2008	2	360	499	1129
4/2/2008	2	351	392	914
5/12/2008	1	265.2	425	1576
5/12/2008	2	324	488	1181
6/23/2008	1	265.8	271	1084

Data for the Delta Energy Center, shown in Table 15 below, have shown lower NO_2 emissions, but greatly increased CO emissions. Two of the startups involved emissions considerably over the 5028 pound limit being considered for Russell City. The longest startup was 4.5 hours.

Table 15: Delta Energy Center Cold Start-Up Summary

Date	Unit	Duration (min)	Total NOx (lbs)	Total CO (lbs)
5/23/2004	1	269	262	3225
5/22/2005	2	231	281	8288
4/17/2006	1	86	152	1202
5/16/2006	2	108	189	3198
4/28/2007	1	175	156	7298
6/5/2008	3	123	119	2599

Data for the Metcalf Energy Center, set forth in Table 16 below, show emissions below both the proposed NO_2 limit and the proposed CO limit, although not with a great safety margin. NO_2 emissions have been up to 70% of the proposed limit, CO emissions have been up to 95% of the proposed limit, and startup duration has been up to 99% of the proposed limit.

Table 16: Metcalf Energy Center Cold Start-Up Summary

Date	Unit	Duration (min)	Total NOx (lbs)	Total CO (lbs)
4/1/2006	2	187	270	4792
5/1/2006	1	358	335	3110
5/8/2006	2	199	232	2686
6/14/2006	2	160	205	3430
5/13/2008	1	98	125	1998
6/2/2008	2	122	129	3022
6/2/2008	1	95	123	2023
6/9/2008	1	86	103	1926
11/24/2008	1	294	151	4429

Finally, data from the Los Medanos Energy Center, set forth in Table 17 below, shows emissions close to the proposed 480 pound NO_2 limit on a number of occasions (with even one slight exceedance), although CO emissions are much lower.

Table 17: Los Medanos Energy Center Cold Start-Up Summary				
Date	**Unit**	**Duration (min)**	**Total NOx (lbs)**	**Total CO (lbs)**
11/24/2004	2	190	453	117
11/13/2006	2	245	421	116
5/23/2007	2	88	172	25
3/18/2008	1	215	485	67

The data the Air District has evaluated suggest that it would not be appropriate to reduce the emissions limits for the proposed Russell City Energy Center below the limits adopted for the Metcalf facility as a mandatory BACT limit. Although some turbines on some occasions have achieved lower emissions rates, the BACT limit must be achievable at all times throughout the facility's operational life. A reasonable safety margin must be included so that the facility will be able to comply with its limits during every startup, even if emissions for specific startups or as an average for startups as a whole may be less. The data from other similar facilities shows that if the Air District were to impose limits substantially below the Metcalf limits, the proposed facility could face difficulty in complying with them. The Air District is therefore proposing to require the same cold startup BACT emission limits as the Metcalf Energy Center: 6 hours total duration, 480 pounds of NO_2, and 5028 pounds of CO.

Hot/Warm Startups

For hot and warm startups, the Air District has concluded that the proposed Russell City facility would be able to achieve emissions limitations substantially below those imposed at Metcalf. Calpine has refined its hot and warm startup operations based on its experience with other facilities, and has committed to keeping hot and warm startup emissions below 125 pounds of NO_2. This emissions level represents a reduction of nearly half from the corresponding Metcalf startup limit, which is 240 pounds. Calpine has committed to this substantial reduction based upon its assessment of its record controlling NO_x emissions during start-up events, as demonstrated by data from its other facilities. Further, although there is normally a trade-off between decreased NOx emissions and increased CO emissions as discussed above, Calpine has committed to achieving the proposed NOx reductions while maintaining CO emissions at the same level adopted for the Metcalf facility (2,514 pounds per event).

Shutdowns

The proposed Russell City facility should be able to achieve significantly reduced shutdown emissions as well. As with hot and warm startups, Calpine has refined its shutdown procedures and has committed to maintaining NO_2 emissions below 40 pounds per shutdown, half the emissions limit imposed at Metcalf, while not increasing its CO emissions.

Tuning Events

Tuning events are expected to be similar in nature to cold startup events, in that they may take up to six hours to complete, may involve operation at low loads where emissions efficiency is compromised, and may require operation without pollution control equipment such as the SCR system. In addition, like cold startups tuning events are expected to occur relatively infrequently, and will be limited to one event per year. For these reasons, the achievable emissions rates for tuning events are expected to be similar to those for cold startups. The Air District is proposing to require emissions during tuning events to comply with the cold startup conditions as the BACT emissions limit.

Conclusion

The Air District is proposing the most stringent emission limits for startups, shutdowns, and tuning event that can reasonably be achieved by the proposed Russell City Energy Center, based on a review of actual operating data and experiences from similar facilities. Emissions from specific startup, shutdown and tuning events may be significantly less than the proposed not-to-exceed permit limits, and the average of all such events is likely to be less than the maximum allowable levels, given the great variability of such events. The District is proposing to require the limits described above as the enforceable BACT limits to ensure that emissions are minimized to the greatest extent feasible while ensuring that the limits are achievable under all operating circumstances.

5. Best Available Control Technology During Commissioning

The combustion turbine/heat recovery boiler equipment is highly complex and has to be carefully tested, adjusted, tuned and calibrated after the facility is constructed. These activities are generally referred to as "commissioning" of the facility. During the commissioning period, each of the combustion turbine generators needs to be fine-tuned at zero load, partial load, and full load to optimize its performance. The dry-low NOx combustors also need to be tuned to ensure that the turbines run efficiently while meeting both the performance guarantees and emission guarantees. The heat recovery boiler and steam pipes also need to be steam-cleaned to ensure that no manufacturing or construction materials or debris that could damage the steam turbine remains within the heat recovery boiler or steam pipes. In addition, the selective catalytic reduction (SCR) systems and oxidation catalysts need to be installed and tuned.

The combustion turbine/heat recovery boiler trains will not be able to meet the stringent BACT limits for normal operations during the commissioning period, for a number of reasons. First, the SCR systems and oxidation catalysts cannot be installed immediately when the turbines are initially started up. There may be oils or lubricants in the equipment from the manufacture and installation of the equipment, which would damage the catalysts if they were installed immediately. Instead, the turbines need to be operated without the SCR systems and oxidation catalysts for a period of time to burn off any impurities that may be left in the equipment. In addition, once all of the pollution control equipment is installed, it needs to be tuned in order to achieve optimum emissions performance. Until the equipment is tuned, it will not be able to achieve the very high levels of emissions reductions reflected in the stringent BACT limits for normal operations.

Because the BACT limits established for normal operations are not technically feasible during the commissioning period, these limits are not "achievable" during this period and are not "Best Available Control Technology" as defined in the Federal PSD Regulations. Alternate BACT limits must therefore be specified for this mode of operation. To do so, the Air District has conducted an additional Top-Down BACT analysis specifically for the required commissioning activities.

The only control technology available for limiting emissions during commissioning is to use best work practices to minimize emissions as much as possible during commissioning, and to expedite the commissioning process so that compliance with the stringent BACT limits for normal operations can be achieved as quickly as possible. There are no add-on control devices or other technologies that can be installed for commissioning activities. Best work practices are a feasible method of limiting emissions as much as possible, however, and so it is the top (and only) control option for purposes of a top-down BACT analysis. There are no energy, environmental or economic impacts that would make this option inappropriate as the BACT control technique, and so the Air District is proposing best work practices as BACT for the commissioning period.

To implement best work practices as an enforceable BACT requirement, the Air District is proposing conditions that will require the facility to minimize emissions to the maximum extent possible during commissioning. The Air District is also proposing numerical emissions limits based upon the equipment manufacturer's best estimates of uncontrolled emissions at the operating loads that the facility will experience during commissioning. The proposed permit conditions will limit emissions to below the following levels:

Table 18: Commissioning Period Emissions Limits		
Air Pollutant	**Proposed Commissioning Period Emissions Limits**	
NO_2	4805 lb/day	400 lb/hr
Carbon Monoxide	20,000 lb/day	5000 lb/hr
PM_{10}	432 lb/day	

Commissioning emissions will also be subject to the annual emissions limits applicable to normal operations. All emissions from commissioning activities will be counted towards the facility's annual limits. Because commissioning is a relatively short-term period, the facility should be able to stay within those limits over the course of the entire year. Counting commissioning emissions towards the annual limits will also provide an additional incentive for the facility operator to minimize emissions as much as possible.

The Air District is also proposing permit conditions to minimize the duration of commissioning activities. The proposed conditions require the facility to tune the combustion turbine/heat recovery boiler trains to minimize emissions at the earliest feasible opportunity; and to install, adjust and operate the SCR systems and oxidation catalysts at the earliest feasible opportunity. The Air District is also proposing to cap the total amount of time that each turbine can operate without the SCR systems and oxidation catalysts at 300 hours. This limit represents the shortest amount of time in which the facility can reasonably complete the required commissioning activities without jeopardizing safety and equipment warranties. The proposed 300-hour limit is based on the following estimates of the time it will take for each specific commissioning activity.

Table 19: Commissioning Schedule	
Commissioning Activity	**Estimated Duration**
First Fire of the combustion turbine, testing, synchronizing during: • Full Speed No Load operation • CTG load test, bypass valve and safety valve tuning	36 hours
Steam blows of the steam piping • HRSG tuning • HRSG restoration and install SCR/CO catalyst	114 hours
Tuning of combustion turbine up to 40% load	12 hours
Run unit at low load to get steam quality for rolling the steam turbine • Establish vacuum/ HRSG tuning • By-pass operation/steam turbine initial roll and trip test • By-pass operation steam turbine load test • Combined cycle drift test • Emissions tuning/drift test	72 hours
Initial roll of the steam turbine • CTG on by-pass/steam turbine load test	10 hours
Tune SCR and CO Catalyst-ammonia calibration	19 hours
Cal-ISO certification	30 hours
Contingency	16 hours
TOTAL:	300 hours

The Air District also reviewed commissioning times for other similar facilities to verify these estimates. Calpine's Delta Energy Center, which began operation in 2002, completed commissioning for its three turbines in 96, 296, and 207 hours, respectively, indicating that 300 hours is an appropriate limit. In addition, the wide variation in the number of hours required to commission these three turbines highlights the unpredictability inherent in commissioning any individual turbine system. This unpredictability underscores the importance of allowing sufficient time to ensure that all required commissioning activities can be completed. The Air District also reviewed permit limits from other recent power plant projects in the Bay Area, several of which had commissioning period limits of 500 hours. The project applicant is confident that it can complete commissioning in 300 hours, however, based upon its extensive experience commissioning similar combustion turbines, which will allow it to conduct the commissioning process more efficiently.

Compliance with these proposed conditions for the commissioning period will be monitored by Continuous Emissions Monitors that the applicant will be required to install before any commissioning work begins, and through a written commissioning plan laying out all commissioning activities in advance, which the applicant will be required to submit to the Air District for review.

B. Cooling Tower

Cooling towers are heat removal devices used to remove excess heat from the facility's cooling system. The Russell City Energy Center is proposing to use a wet cooling tower system in which water is circulated through a condenser to absorb the heat from the steam produced by the steam turbine. The condensed water is then circulated through the cooling tower where some of it is evaporated, removing excess heat. The cooling water is then returning to the condenser by a re-circulating pump.

Cooling towers can cause small amounts of Particulate Matter emissions from solids, commonly referred to as Total Dissolved Solids (TDS), in the cooling water. As the cooling water is circulated through the tower, water droplets known as "drift" can become entrained in the air stream and leave the cooling tower into the atmosphere. Solids in the drift droplets can then become Particulate Matter emissions.

STEP 1: Identify Control Technologies

High-efficiency drift eliminators: High-efficiency drift eliminators are commonly used in cooling towers to control the Particulate Matter emissions. These devices collect drift droplets contained in the air exiting the cooling tower and return them to the water in tower. High efficiency drift eliminators can control the drift to less than 0.0005 percent (0.5 gallons per 100,000 gallons of flow) of the cooling tower circulating water flow. Drift eliminators are able to capture nearly 100 percent of the droplets which are larger than 10 microns ("µm") in diameter. The Air District has not identified any other control technologies for reducing cooling tower drift.

STEP 2: Eliminate Technically Infeasible Options

High-efficiency eliminators have been demonstrated on many power plant installations. The technology is technically feasible and available for the cooling tower proposed for the Russell City Energy Center.

STEP 3: Rank Remaining Control Technologies by Control Effectiveness

As the only available control technology, the Air District ranks the No. 1 control technology for cooling tower emissions. The Air District has found no collateral environmental, economic, or energy impacts that would suggest that this is not an appropriate control technology, and so it has determined that the use of high-efficiency drift eliminators is BACT control technology. As the Air District has selected the top control technology for the project, no further top-down analysis is required.

Determination of BACT Emissions Limit for Cooling Tower Emissions:

It is not feasible to implement a limit on cooling tower Particulate Matter emissions directly, as the solids that form the Particulate Matter are contained within the water droplets emitted in the drift. Instead, the Air District proposes a limit on the amount of drift itself as a surrogate for Particulate Matter emissions. The amount Particulate Matter emitted from the cooling tower will be proportional to the amount of drift, and so limiting drift is an appropriate means of limiting Particulate Matter.

High-efficiency drift eliminators can reliability achieve a drift rate of less than 0.0005%.[44] The Air District has examined permit limits from 13 other similar facilities using high-efficiency drift eliminators on wet cooling towers, and found that they all have limits of 0.0005%.[45] The Air District is therefore proposing 0.0005% cooling tower drift as the BACT limitation for Particulate Matter for this source.

C. Emergency Fire Pump Engine

The proposed Russell City Energy Center will require an emergency diesel fire pump engine to be used in case of emergency to provide water to fight fires. The fire pump engine would be used solely to pressurize a fire suppression system. It would be operated only in case of emergency, as well as for short periods for inspection, maintenance, and testing, as required by the standards of the NFPA to ensure reliability in case of fire.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x including NO_2), hydrocarbons, Carbon Monoxide, and Particulate Matter (including both visible (smoke) and non-visible emissions). Nitrogen oxide formation is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The other pollutants (hydrocarbons, Carbon Monoxide, and Particulate Matter) are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust.

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[44] Source test results for Metcalf Energy Center.

[45] The 13 facilities are: PICO-Von Raesfeld Power Plant; Inland Empire Energy Center; Tesla Energy Center; Vineyard Energy Center-Utah; Blythe Energy Center; Delta Energy Center; Rio Linda Power Plant; Las Vegas Cogen; East Altamont Energy Center; Mission-Sun Valley; Mission-Walnut; Pastoria Energy Center; and Liberty Energy V, XX, and XXIII.

The Air District has undertaken the following BACT analysis for NO_2, Carbon Monoxide and Particulate Matter for the diesel fire pump engine in accordance with EPA's PSD permitting guidelines.[46]

STEP ONE: Identify Control Technologies

The Air District has identified three primary types of control technologies that could potentially be used to reduce air pollutant emissions from the diesel fire pump engine: the use of clean diesel fuel; combustion technologies to limit pollutant formation during combustion; and post-combustion technologies that remove pollutants that are formed before they can enter the atmosphere.

Clean Fuel Technologies:

Recent advances in diesel fuel formulation technology can help reduce emissions when the fuel is combusted in diesel engines. Such technologies include the following:

Ultra-Low Sulfur Fuel: The use of diesel fuel that meets the CARB ultra-low sulfur diesel fuel standard (< 0.015% by weight sulfur) can reduce the amount of Particulate Matter and NO_2 formed during combustion. Reducing the amount of sulfur in the fuel reduces the amount of Particulate Matter generated because the sulfur in the fuel is mostly converted into sulfur dioxide during combustion, which reacts with water to form sulfuric acid, a particulate that contributes to total Particulate Matter emissions. An ultra-low sulfur diesel fuel will limit the amount of sulfur that forms PM emissions. In addition, using ultra-low sulfur fuel reduces NO_2 emissions because the hydro-treating technique used to remove the sulfur from the diesel fuel also removes nitrogen, leaving only trace amounts. Reducing the amount of nitrogen in the fuel reduces the amount of nitrogen available to form NO_2 during combustion.

Fuel Additives: The procedure broadly defines fuel additives to be substances that are present in cylinder during combustion for any of a number of different purposes, such as decreasing emissions or assisting in the operation of another diesel emission control system. One common type of fuel additive, known as a "fuel borne catalyst" (FBC), is routinely used in several countries in Europe to assist in the regeneration of DPFs. FBCs are metallic in nature (e.g., cerium, iron, and platinum) and are added in low concentrations to diesel fuel. Particles of the FBC get associated with soot particles during the combustion process and significantly lower the soot combustion temperature.

Combustion Technologies:

There are also a number of design features that can be used for diesel engines that can reduce the amount of air pollutants generated during combustion of the fuel, including NO_2, Carbon Monoxide and Particulate Matter. These features include:

Turbocharging: A turbocharger is an exhaust gas-driven air compressor used for forced-induction of an internal combustion engine. The purpose of a turbocharger is to increase the mass of air entering the engine to create more power. Turbocharging decreases emissions due to increased efficiency (less fuel is combusted to achieve the same output without turbocharging). Turbochargers

[46] Note that this diesel engine is also subject to stringent regulations under California law over and above the federal regulations under the Federal PSD Program. *See California Code of Regulations section 93115*

reduce both NOx and PM emissions by approximately 33 percent when compared to naturally aspirated engines.

Intercooler: An intercooler, or charge air cooler, is an air-to-air or air-to-liquid heat exchange device used on turbocharged internal combustion engines to increase the intake air charge density through cooling. A decrease in air intake temperature provides a denser intake charge to the engine and allows more air and fuel to be combusted per engine cycle, increasing the output of the engine.

Retarding Injection Timing: Retarding the injection of fuel into the engine reduces the peak flame temperature, which improves NOx emission but typically results in higher PM emissions. The fuel starts combustion at the point when it is injected into the cylinder. Retarding the timing of the fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NOx formation. Retarding the injection timing reduces NOx from all diesel engines; however, the effectiveness is specific to each engine model. Moreover, retarding injection decreases the horsepower output of the engine. The amount of NOx reduction with ITR diminishes with increasing levels of retard.

Exhaust gas recirculation (EGR): Exhaust gas recirculation allows a controlled portion of spent combustion gases to circulate back into the intake system where it mixes with pre-combustion air. The exhaust serves as a diluent to lower the in-cylinder oxygen concentration and also to increase the heat capacity of the air/fuel mixture. This reduces peak combustion temperature and the rate of combustion, thus reducing NOx emissions. Typical NOx reductions achieved by EGR retrofits are about 40 to 50 percent.

Pre-Combustion Chamber: A precombustion chamber is a prechamber in the engine that ignites a fuel-rich mixture that propagates into the main combustion chamber where additional air is introduced to make the air/fuel mixture lean. The high exit velocity from the precombustion chamber results in improved mixing and complete combustion of the lean air/fuel mixture, which lowers combustion temperature, thereby reducing NOx emissions.

Post-Combustion Controls:

Finally, there are several post-combustion technologies that could potentially be used to remove emissions from the diesel firepump engine's exhaust before they are emitted to the atmosphere.

Selective Catalytic Reduction Systems: Selective catalytic reduction (SCR) systems are a form of after-treatment technology that use a reagent, typically ammonia or urea, to convert NOx to nitrogen and oxygen over a catalyst. SCR is described in detail above in connection with the combustion turbine/heat recovery boiler BACT analysis (*see* Section V.A.1 above). SCR requires exhaust temperatures to be between 250 and 450 degrees Celsius in order to work properly.

Lean-NOx Catalyst: Another after-treatment based NOx control technology is referred to as the lean-NOx catalyst. Similar in principle to an SCR system, a Lean-NOx Catalyst system relies on injection of a reagent upstream of the catalyst to reduce NOx emissions.

NOx Adsorbers: NOx adsorbers, also called NOx traps, are one of the newest emission control strategies under development. They employ catalysts to which NOx in the exhaust stream adsorbs when the engine runs lean. After the adsorber has been fully saturated with NOx, the system is regenerated with released NOx being catalytically reduced when the engine runs rich. NOx reductions in excess of 80-90 percent have been reported. A prerequisite for proper functioning of this new technology is low-sulfur fuel (to prevent fouling of the catalyst).

Diesel Oxidation Catalyst: A diesel oxidation catalyst uses a very light loading of platinum catalyst to oxidize compounds such as Carbon Monoxide and many of the hydrocarbons that condense into droplets and form Particulate Matter upon leaving the exhaust system and entering the atmosphere. Diesel oxidation catalysts are typically able to reduce PM emissions by about 25 percent. However, they do not reduce the solid soot particles in PM by any appreciable amount.

Diesel Particulate Filters: Diesel particulate filters are more effective at reducing emissions of Particulate Matter than diesel oxidation catalysts. This technology uses a filter medium such as a porous ceramic or sintered metal material that permits gases in the exhaust to pass through but traps the Particulate Matter. These filters are very efficient in reducing Particulate Matter emissions, typically achieving reductions in excess of 85 percent.

Fabric Filter Baghouses: Baghouses collect particulate matter by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags which are periodically shaken to release the particulates into hoppers.

STEP TWO: Eliminate Technically Infeasible Options

Clean Fuel Technologies:

Ultra-low sulfur Diesel fuel is available and demonstrated for stationary compression ignition engines. It is technically feasible for the fire pump engine.[47] The use of fuel additives is still in a developmental stage in the United States, however, and is not commercially available. Fuel additives are not technically feasible for the fire pump engine

Combustion Controls:

The design of a diesel engine – including the choice of combustion technologies to reduce the formation of air pollutants during combustion – is determined by the manufacturer of the engine, not by the end-user. Diesel engine users, such as the Russell City Energy Center here, are limited to the engines that are commercially available from manufacturers. The determination of what combustion control technologies are technically feasible must therefore focus on what technologies are commercially available to be purchased for this project.

The technologies that are commercially available are those that manufacturers are using to achieve the EPA Tier 2 requirements for engines of the class needed for emergency fire service at the Russell City Energy Center.[48] There are no Tier 3 or Tier 4 engines currently available that can serve the facility's emergency fire service needs.

Post-Combustion Controls:

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[47] Under CARB regulations, the emergency fire pump engine will use only California ultra-low sulfur Diesel fuel when operating.

[48] December 18, 2006 Clarke Letter; South Coast AQMD - Tier 3 direct drive fire pump engines are not available.

Post-combustion controls are not feasible for direct-drive fire pump engines of the type needed to serve the emergency fire suppression needs of the Russell City Energy Center.[49] Addition of a catalytic device to the exhaust system would be technically infeasible, due to the variable load of the engine and the nature of the control system. Injection of a reagent into the engine exhaust to control pollutants (mainly NO_x) is dependent on a constant steady state engine load. But the fire pump engine will need to operate effectively under highly variable loads, thus ruling out this type of control technology. Installation of other after-treatment devices such as particulate traps will also compromise reliability, performance, and safe operation of the fire pump.[50]

In addition, the use of post-combustion control technologies would be incompatible with the fire pump's role as a safety device for use in emergencies. Direct-drive fire pump engines of the type proposed for the Russell City Energy Center are designed differently than other stationary or off-road diesel-fueled engines. Direct-drive fire pump engines must meet the stringent National Fire Protection Association (NFPA) standards that establish minimum requirements for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel types used, instrumentation and control, and exhaust systems, among others. The direct-drive fire pump engine, and anything connected to the engine that may affect its performance abilities, must be tested and certified by an independent agency (*e.g.* Underwriters' Laboratories) to be conforming to the requirements of NFPA Standards 20 (Installation of Stationary Pumps for Fire Protection) and/or 25 (Inspection, Testing and Maintenance of Water-Based Fire Protection Systems).[51] Adding exhaust system controls to these engines would void the existing certifications.[52]

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

Both feasible control technologies, ultra-low sulfur diesel fuel and Tier 2 engine technology, are ranked No. 1. These two technologies are not mutually exclusive and can be used in conjunction with each other to achieve the lowest feasible emissions levels. The Air District has therefore determined that the use of these two technologies for the emergency fire pump engine is the Best Available Control Technology. There are no collateral adverse impacts that would call into question the selection of these technologies as BACT. Because the Air District has chosen the top-ranked control technologies, no further analysis is required under EPA's top-down BACT approach.

Determination of BACT Emissions Limit for Firepump Emissions:

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[49] Diesel engine emissions are currently controlled through improvements to the basic engine, rather than through the use of after-treatment technologies (the exception being diesel oxidation catalysts). *See* Washington State University Extension Energy Program report.

[50] Clarke, letter dated December 11, 2006 to the South Coast Air Quality Management District.

[51] In addition, even if add-on post-combustion technologies were technologically feasible for an emergency fire pump engine, the would not be cost-effective for an engine that is operated only a small number of hours per year. With a small number of operating hours, the cost per hour of operation of adding a post-combustion control system would be astronomical.

[52] March 30, 2005, letter from the California Air Resources Board (CARB) to Clarke Fire Protection Products (recognizing the limited number of options that direct-drive fire pump manufacturers have in replacing or modifying engines); Clarke December 11, 2006, letter to the South Coast Air Quality Management District.

For the fire pump engine, technological and economic limitations make the imposition of a numerical emissions limit infeasible. Determining compliance using an emissions limitation would require direct monitoring of the emissions stream from the engine itself, either using a continuous emissions monitor permanently installed on the engine or through periodic source tests. Both of these alternatives would be prohibitively costly, especially for an engine that will be operated only for a small number of hours each year. In addition, conducting periodic source tests would require the engine to be started up and operated solely for the purpose of testing, which would add significantly to the annual operating hours and associate emissions.

The BACT requirement can more feasibly and economically be enforced by requiring that the facility use an EPA-certified Tier 2 diesel engine. The EPA certification process requires testing by the engine manufacturer to ensure that the engine will meet the established Tier 2 limits. Tier 2 engines have emission rates below 4.27 grams/hp-hr NO_2, 0.33 grams/hp-hr Carbon Monoxide, and 0.12 grams/hp-hr Particulate Matter.[53] By requiring the facility to use an EPA-certified engine, the Air District can ensure that the engine will comply with the BACT requirement and the substantive Tier 2 emissions limits. The proposed Federal PSD Permit authorizes the use of a Clarke JW6H-UF40 engine, which is certified to EPA Tier 2. Use of a different, non-certified engine would not be authorized under the permit. The engine will have to use ultra-low-sulfur diesel fuel because in California that is the only fuel that can be sold for use in such engines.

D. Greenhouse Gases and Best Available Control Technology

The Air District has also examined the potential for greenhouse gas emissions from the proposed facility. The District's conclusions are outlined in this section.

1. Global Climate Change and the Current State of Greenhouse Gas Regulation

As the Bay Area's primary air quality regulatory agency, the Air District is working proactively to address the problem of global climate change. Global climate change poses a significant risk to the San Francisco Bay Area with impacts such as rising sea levels, reduced runoff from snow pack in the Sierra Nevada, increased air pollution, impacts to agriculture, increased energy consumption, and adverse changes to sensitive ecosystems. Global climate change is exacerbated by emissions of so-called greenhouse gases, which include primarily carbon dioxide (CO_2) but also gases such as nitrous oxide (N_2O) and methane (unburned natural gas), among others. The generation of electricity from burning natural gas produces greenhouse gases in addition to the criteria air pollutants addressed above.[54] For this reason, fossil-fuel fired power plant projects implicate global climate change issues and have recently become the subject of heightened scrutiny in this area.

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[53] EPA Air Nonroad Diesel Rule, EPA420-F-04-032, May 2004.

[54] Fossil-fuel fired power plants have the potential to emit a number of greenhouse gases, including CO_2, CH_4 and nitrous oxide (N_2O). CO_2 emissions represent the largest Greenhouse Gas emissions, however, and provide a useful shorthand for referring to emissions of all greenhouse gases combined. Emissions of greenhouse gases in general are therefore often reported in terms of "CO_2 equivalents", which means the amount of CO_2 emissions that would have the same climate impact as a suite of multiple greenhouse gases. The use of "CO_2 equivalents" allows for a meaningful comparison among different emissions made up of varying combinations of different greenhouse gases. The Air District therefore focuses on CO_2 equivalents in this analysis to evaluate greenhouse gas emissions.

The Air District's efforts are closely coordinated with California's initiatives to address global climate change at the state level. The California Global Warming Solutions Act of 2006 (AB32) requires the California Air Resources Board (ARB) to adopt a statewide Greenhouse Gas emissions limit equivalent to the statewide GHG emissions levels in 1990 to be achieved by 2020. To achieve this end, ARB was given a mandate to adopt rules and regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions. The ARB is expected to adopt early action GHG reduction measures in the near future to reduce greenhouse gas emissions by 2020. ARB has adopted regulations requiring mandatory GHG emissions reporting. The facility is expected to report all GHG emissions to meet ARB requirements.

The Electricity Greenhouse Gas Emission Standards Act (SB136812) was also enacted in 2006, requiring that base-load generation resources or contracts be subject to a Greenhouse Gas or Environmental Performance Standard. At its January 25, 2007, meeting, the California Public Utilities Commission (CPUC) adopted an Emissions Performance Standard for the state's Investor Owned Utilities of 1,100 pounds (or 0.5 metric tons) CO_2 per megawatt-hour (MW-hr). The Emissions Performance Standard applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California.

The status of Greenhouse Gas regulation is not as well developed under the federal PSD Permit program, however. Federal PSD Permit requirements apply only to "Regulated NSR Pollutants", and "Regulated NSR Pollutants" are defined as (among other things) pollutants that are "subject to regulation" under the Clean Air Act ("CAA"). *See* 40 C.F.R. §§ 52.21(j)(2), (b)(50). Whether Greenhouse Gas emissions are subject to Federal PSD Permit requirements therefore turns on whether they are "subject to regulation" under the Clean Air Act. The United States Supreme Court has recently determined that certain Greenhouse Gases are "Air Pollutants" within the meaning of CAA Section 302(g). *See Massachusetts v. EPA*, 549 U.S. 497, 127 S. Ct. 1438 (2008), meaning that EPA may regulate them under the CAA if appropriate. That ruling did not resolve the issue of whether Greenhouse Gases are "subject to regulation" for purposes of the PSD program. EPA permitting authorities have taken the position that "subject to regulation" means that the agency has actually adopted substantive regulatory requirements for a pollutant, and that EPA has not done so with Greenhouse Gases, and so the PSD Permitting Requirements are not applicable. Others have taken the position that "subject to regulation" means only that EPA would have the authority to regulate the pollutant under the CAA, and that it is clear after the *Massachusetts* decision that EPA does have authority to regulated Greenhouse Gases as "Air Pollutants" under CAA Section 302(g).

This issue of whether Greenhouse Gases are subject to Federal PSD Permit requirements has been raised in several contexts, most notably in appeals of PSD Permits to EPA's Environmental Appeals Board ("EAB"). In the one substantive decision that the EAB has reached to date, the EAB remanded the permit to EPA Region 8 to consider the issue more thoroughly. *See* Order Denying Review In Part and Remanding In Part, *In re Deseret Power Elec. Coop. (Bonanza)*, PSD Appeal No. 07-03, __ E.A.D. __ (EAB Nov. 13, 2008). In that decision, the EAB determined that EPA has the discretion under the CAA to decide whether or not Greenhouse Gases should be subject to the Federal PSD Program, and that the agency has not made any historical or current determination of whether to exercise that discretion one way or another. The EAB therefore remanded the issue to EPA Region 8 with directions that the Region should consider from scratch the issue of whether the

Agency should exercise its discretion to regulate Greenhouse Gases under the PSD Program. The EAB also suggested that it may be more appropriate for the Agency to address the issue through a nationwide rulemaking, rather than through individual case-by-case PSD permitting decisions. *Id.*, Slip. Op. at p. 63-64. It therefore remains, for the time being, an open question as to whether Greenhouse Gas emissions from the proposed Russell City Energy Center should be subjected to Federal PSD Permit requirements.

For the Russell City Energy Center, the Air District is the PSD Permit issuing authority acting on behalf of EPA pursuant to the Delegation Agreement between the two agencies. In this role, it would normally fall to the Air District to determine how EPA should and will exercise its discretion whether to subject Greenhouse Gas emissions to the Federal PSD Program in the wake of the *Deseret Power* decision. There is very little definitive evidence as to how EPA will decide this issue, however, and it is therefore difficult for the Air District to make such a determination. But for this project such a determination is not necessary, because the applicant has requested that the Air District assume without deciding that Greenhouse Gases are subject to PSD Permit requirements and undertake a PSD Top-Down BACT analysis for the proposed project's Greenhouse Gas emissions. The applicant believes that the Russell City Energy Center as proposed utilizes technology to limit greenhouse gas emissions that meets the definition of Best Available Control Technology as used in the Federal PSD Regulation (40 C.F.R. § 52.21(b)(12)). The applicant has therefore requested that the Air District undertake a Greenhouse Gas BACT analysis and impose an enforceable Greenhouse Gas BACT permit limit, which the applicant will voluntarily accept regardless of whether BACT is required for Greenhouse Gases.

2. Greenhouse Gas BACT Analysis for the Proposed Russell City Energy Center

Because the applicant has voluntarily requested a BACT analysis for greenhouse gases, the Air District conducted a BACT analysis for Greenhouse Gases for the Russell City Energy Center without deciding whether EPA would decide that Greenhouse Gases are subject to the Federal PSD permitting requirements. The Air District's analysis is set forth in this section, following EPA's five-step "top-down" BACT methodology.

In conducting this analysis, the Air District consulted the sources of previous BACT determination such as the federal and California BACT clearinghouses discussed above in connection with the BACT analyses for other pollutants. As BACT has never been applied to greenhouse gases, however, these sources of information did not provide any guidance to inform this analysis. Given the absence of prior BACT determinations, the Air District also reviewed various regulatory limits on greenhouse gas emissions that have been enacted recently. Regulatory limits do not necessarily reflect the most appropriate emissions limit for a specific facility, which must be determined on a case-by-case basis, but they can be helpful in providing some context for making such a determination. The regulatory limits that have been adopted for greenhouse gas emissions reviewed by the Air District are set forth in Table 20.

TABLE 20: Regulatory Limits on Greenhouse Gas Emissions From Combined-Cycle Power Plants	
Jurisdiction	Greenhouse Gas Emissions Limit (CO_2 Equivalent)
Delaware (Distributed generators installed before 1/1/2012)[55]	1,900 lb/MW-hr
Delaware (Distributed generators installed 1/1/2012 or later)[56]	1,650 lb/MW-hr
Massachusetts[57]	1,800 lb/MW-hr
Washington[58]	1,100 lb/MW-hr
California[59]	1,100 lb/MW-hr
Oregon[60]	675 lb/MW-hr (calculated after subtracting offsetting emissions credits)

The Air District's top-down BACT analysis for greenhouse gases is set forth below.

<u>STEP ONE: Identify Control Technologies</u>

Combustion Controls

CO_2 is a product of combustion of fuel containing carbon, and it is inherent in any power generation technology using fossil fuel. There is no way to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place, as with the regulated air pollutants addressed above.

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55 Delaware Department of Natural Resources and Environmental Control, Regulation No. 1144: Control of Stationary Generator Emissions, § 3.2; 73 Fed. Reg. 23,101, 23,102-103 (Apr. 29, 2008) (codifying approval in the Code of Federal Regulations at 40 C.F.R § 52.420). This SIP approval is currently under review by EPA's Office of Air and Radiation.

56 *Id.*

57 310 Mass. Code Regs. 7.29.

58 Wash. Rev. Code Ann. § 80.80.040. This limit applies to all baseload electric generation for which electric utilities enter into long-term financial commitments on or after July 1, 2008. "Baseload electric generation" means electric generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent. *Id.* § 80.80.010.

59 CPUC, Interim Opinion On Phase 1 Issues: Greenhouse Gas Emissions Performance Standard, Jan. 2007. In 2006 California adopted SB 1368, requiring that the California Public Utilities Commission (CPUC) establish an interim emissions performance standard (EPS) for long-term procurement contracts at a level no be greater than emissions from a combined cycle gas turbine plant. The CPUC undertook a rulemaking procedure and established an EPS for covered facilities of 1,100 pounds of CO_2 per megawatt hour. The California Energy Commission (CEC) approved a similar requirement for municipal utilities. The CPUC ruling found that CCGTs were the most efficient technology for burning of fossil fuels.

60 Or. Admin. Rules 345-024-0550 (limit expressed as 0.675 lb CO_2/kW-hr). This limit applies base-load gas plants and non-base load plants, and it can be met through the use of offsets. This means that actual CO_2 emissions can be higher than the stated limit, if the facility provides CO_2 emissions credits obtained by reducing CO_2 emissions elsewhere.

The only effective means to reduce the amount of CO_2 generated by fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output. This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating power.

The combined-cycle natural gas turbine technology proposed for the Russell City Energy Center is among the most efficient electrical generating technology created to date. Combined-cycle natural gas turbines are a more efficient and cleaner burning source of electricity than any other fossil fuel technology. EPA has found that, compared to the average air emissions from coal-fired generation, natural gas produces half as much CO_2.[61] (Note also that natural gas is far cleaner than other carbon fuels in terms of other air pollutants such as particulate matter, SO_2, mercury, and other heavy metals.) The use of such high-efficiency energy generation technology is a control technology that will limit greenhouse gas emissions from the facility.

Post-Combustion Controls

Beyond using high-efficiency generation technologies to reduce the amount of greenhouse gases created when the power is generated, there are technologies emerging to capture greenhouse gases after they are generated and prevent them from entering the atmosphere where they can contribute to global climate change. These emerging post-combustion capture technologies generally consist of processes that separate CO_2 from flue gas after conventional combustion, and then inject it into geologic formations (such as oil and gas reservoirs, unmineable coal seams, and underground saline formations) or store it in terrestrial repositories. Such technologies might generally be considered as analogous to other technologies that remove or reduce criteria pollutant concentrations pollutants from flue gas streams, *e.g.*, ammonia injection as part of selective catalytic reduction (SCR) for NOx reduction. District staff have identified carbon capture and storage as the only potential post-combustion control technology for CO_2 emissions. If implemented, this technology would further reduce CO_2 emissions beyond the levels achievable by using energy-efficient power generation equipment.

STEP TWO: Eliminate Technically Infeasible Options

Combustion Controls

Energy-efficient power generation is a feasible and proven technology. The energy-efficient natural-gas fired combined-cycle combustion turbine technology proposed for the Russell City Energy Center is such a technology.

Post Combustion Controls

In contrast to readily-available high-efficiency generation technologies, emerging carbon capture and sequestration technologies are in their infancy and are not currently feasible for projects such as the proposed Russell City Energy Center. There are currently no carbon capture and sequestration

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[61] *See* EPA, *Natural Gas*, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html.

systems commercially available for full-scale power plants in the United States. The U.S. Department of Energy (DOE) has indicated that its goal is to develop carbon capture and sequestration at a research and development scale by 2012 and that it expects integrated systems be available for full commercial deployment in the 2025 timeframe. (*See* 73 Fed. Reg. at 44,370.) A survey conducted at the 2007 Electric Power Research Institute (EPRI) summer seminar found that only five percent of the participants (industry professionals) indicated they thought CO_2 capture would be commercially available by 2015, only 24 percent thought it would be available by 2020, and only 15 percent by 2025.[62] EPA itself has recognized that add-on controls may not be adequately demonstrated for CO_2. (*See* 73 Fed. Reg. at 44,508.)

In addition, even if carbon capture and sequestration were fully matured, the feasibility of such controls for a particular power plant would depend on the availability of appropriate sequestration sites (sinks) in the vicinity of the plant.[63] While basins within Alameda County are under investigation for the potential for carbon sequestration, there are no such sites that have been demonstrated as appropriate for sequestration at this time.

Finally, carbon capture and sequestration may also have ancillary environmental and societal impacts that need further evaluation before the technology can be considered feasible. For example, there may be the potential for effects on sensitive species and other wildlife, and cultural and environmental justice issues. Land use and water and mineral resources will also be important considerations. Sequestration of carbon in the ground also runs the risk of leakage into the air, and the science and technology of remediating leakage is still emerging.[64] These issues highlight the further development that is needed before this technology can be considered a feasible option for controlling greenhouse gas emissions.

For the foregoing reasons, the Air District eliminated carbon capture and sequestration from consideration as an available control technology for purposes of its BACT analysis. The Air District will continue to monitor the development of carbon capture sequestration as a potential control technology for the future, however.

<u>STEP THREE: Rank Remaining Control Technologies by Control Effectiveness</u>

Based on the first two steps of the top-down BACT analysis, there is only one available and feasible control technology to reduce greenhouse gas emissions from the project, the use of high-efficiency power generation technology. This technology is therefore ranked No. 1 in the BACT analysis, and is the technology that the Air District would choose if BACT were required for a Federal PSD Permit.

[62] Washington Department of Ecology, Preliminary Cost Benefit and Least Burden Analyses, Document 08-02-007, at 10 (Feb. 2008).
[63] Burton, *et al.*, Geologic Carbon Sequestration Strategies for California, CEC Systems Office Report to the Legislature, at 20.
[64] *Id*., at 85.

There are no collateral adverse impacts that would call into question the selection of high-efficiency power generation technology as BACT.[65] Because the Air District has chosen the top-ranked control technology, no further analysis is required under EPA's top-down BACT approach.

Determination of BACT Emissions Limit for Greenhouse Gases

Having chosen high-efficiency power generation technology as the Best Available Control Technology, the next step in applying the BACT requirement is to adopt a numeric limitation for greenhouse gas emissions. Again, EPA has not determined whether it should exercise its discretion to regulate greenhouse gases under the Federal PSD program, but the District has calculated what an appropriate BACT emission limitation would be for greenhouse gases if they were subject to the BACT requirement at the voluntary request of Calpine.

According to data compiled by the California Energy Commission, natural-gas burning combined-cycle combustion turbine technology can achieve an efficiency of around 56%.[66] The Westinghouse 501F turbines proposed for the Russell City Energy Center are rated at 55.8% efficiency, squarely within the range of the best-performing combined-cycle turbines.[67] Based on this level of performance, the Energy Commission has concluded that the project's equipment will "represent the most efficient combination to satisfy the project objectives." (Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-6.)

To determine an appropriate CO_2 emissions limitation achievable for this level of energy-efficient technology, the Air District used emissions performance data from other similar facilities. Information from the Energy Commission from the years 2004 and 2005, which showed emissions from baseload combined-cycle gas turbine power plants ranging from 794 lbs to 1058 lbs per MW-hr of electricity generated. The Air District also reviewed data from two similar Calpine power plants, the Delta Energy Center and the Metcalf Energy Center, which reported 2006 emissions of 855 and 912 lb/MWhr, respectively, when calculated in accordance with the methodology provided by the CEC for purposes of demonstrating compliance with the EPS.

This data is highly informative as to the general level of CO_2 emissions performance that can be expected from these turbines during their operational lives. The data must be viewed conservatively in determining what emissions limits would be appropriate as mandatory BACT compliance limits, however, given that the data represents a snapshot of turbine performance and not a continued

[65] California Energy Commission Decision for the Russell City Energy Center AFC, Alameda County (Sept. 11, 2002), at p. 67.

[66] This determination was made based on a comparison of three individual models of combined-cycle combustion turbines using data from Gas Turbine World, an independent technical magazine that covers the gas turbine industry. *See* Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4. The turbines evaluated had nominal energy efficiencies of between 55.8% and 56.5%. During review of the September 2007 amendment to that decision, CEC staff "testified that the proposed changes would not change any of the findings or conclusions in the 2002 Decision." Presiding Member's Proposed Decision, Russell City Energy Center, Amendment No. 1 (01-AFC-7C), Alameda County, August 23, 2007 (CEC-800-2007-003-PMPD), at 57.

[67] *See* Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4.

demonstration of compliance with an enforceable CO_2 emission limitation throughout the turbines' total operational lifetime. As there have historically been no enforceable emissions limitations on CO_2 emissions, such comprehensive data is not available at this time. For these reasons, caution must be exercised in determining what emissions level would be appropriate as an enforceable upper limit on emissions exceedances of which would be subject to legal enforcement action. Such an approach to establishing enforceable limits has been endorsed by EPA, which has made clear that BACT limits should not necessarily reflect the maximum possible emissions control efficiency that can be achieved under the most favorable conditions, but rather at levels that will allow facilities to achieve compliance consistently over time under all operating conditions. *See In re Prairie State Generating Co.*, PSD Appeal No. 05-05, 13 E.A.D. __, slip. op. at 72 (EAB Aug. 24, 2006), *aff'd*, *Sierra Club v. EPA*, 499 F.3d 653 (7^{th} Cir. 2007), *reh'g denied and reh'g en banc denied,* 2007 U.S. App. LEXIS 24419 (7^{th} Cir., Oct. 11, 2007); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 188 (EAB 2000).

The Air District has therefore concluded that, without a demonstrated track record of compliance with enforceable permit limits and the need to ensure that the facility would be able to comply with an emissions limit under all foreseeable operating conditions, a reasonable compliance margin would be necessary in adopting any enforceable BACT limit for CO_2 emissions. Based on the available data the Air District has reviewed for similar turbines, and incorporating a reasonable compliance margin, the Air District concludes that if BACT is required for CO_2 emissions, an enforceable limit of 1100 lb/MW-hr would best represent the BACT requirement in the PSD regulation. The Air District notes that this emissions limitation would be consistent with the most stringent emissions standard in any regulatory requirement adopted to date, as discussed in the beginning of this analysis.[68] This limitation also compares favorably with the average emissions rate for all natural gas fired power plants, which EPA found to 1135 lbs/MW-hr.[69]

To comply with a CO_2 emissions limit of 1100 lb/MW, the facility would be required to limit its CO_2 emissions to 684,200 lb/hr, given its maximum power output of 622 MW. CO_2 emissions are proportional to the amount of fuel burned, and so the Air District is proposing to ensure compliance with this standard through an enforceable fuel throughput limit, expressed in terms of the heat input of the fuel burned (Higher Heating Value (HHV)).[70] CO_2 emissions correlate to heat input at 116.19 pounds of CO_2 emitted per million British thermal units (MMBtu) of heat input. A 684,200 lb/hr CO_2 emissions rate therefore corresponds to 5,888.6 MMBtu of heat input for both turbine/HRSG trains combined, or 2,944.3 MMBtu for a single turbine/HRSG train. Proposed condition No. 13 limits the heat input to 2,238.6 MMBtu per turbine/HRSG train, and will ensure that CO_2 emissions do not exceed the BACT emissions limit outlined above. Corresponding heat input limits in proposed conditions Nos. 14 and 15 will ensure compliance on a daily and annual basis as well. To the extent that EPA may exercise its discretion and require PSD permits to ensure that facilities will use BACT to control greenhouse gas emissions, the proposed Russell City Energy Center will comply with BACT based on these enforceable permit conditions.

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[68] *See* Table 20 above. Note that Oregon's limit may be complied with using offsets, meaning that plants subject to the limit are not themselves required to meet the emissions limit. As BACT limits must be complied with regardless of offsets, Oregon's limit is not directly comparable in a BACT analysis.

[69] EPA, *Natural Gas*, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html.

[70] *See* Appendix A for the correlation between natural gas combusted and the amount of CO_2 generated.

VI. PSD AIR QUALITY IMPACT ANALYSIS

The Federal PSD regulations and corresponding Air District regulations require that the District undertake an air quality impact analysis for each facility subject to PSD permit requirements. The Air District has done so for the proposed Russell City Energy Center. The results of this analysis are presented in the *Summary of Air Quality Impact Analysis for the Russell City Energy Center*, set forth in Appendix C. The analysis used sophisticated EPA-approved air pollution models to evaluate the ambient air impacts from air pollutant emissions from the proposed facility. The analysis found that the emissions from the proposed facility would not cause or contribute to air pollution in violation of any applicable National Ambient Air Quality Standard or applicable PSD increment. The analysis also examined the potential for impacts to visibility, soils and vegetation resulting from air emissions from the proposed facility and found no significant impacts. The analysis also examined the potential for associated growth from the facility and found that there would be no significant associated growth. The analysis also examined the potential for impacts to "Class I" areas, which are areas of special natural, scenic, recreational, or historic value (such as National Parks). The analysis found that there would be no significant impact to Class I areas. Full details are set forth in Appendix C Based on this analysis, the proposed facility complies with the air quality impacts analysis requirements in 40 C.F.R. sections 52.21(k) through (p).

VII. OTHER APPLICABLE LEGAL REQUIREMENTS

Beyond the Federal PSD Regulations, there are a number of important non-PSD air quality-related requirements applicable to the proposed Russell City Energy Center. The Air District reviewed these additional applicable requirements in its Final Determination of Compliance for the project, prepared in conjunction with the California Energy Commissioning licensing proceeding. The Air District conducted this review in the Final Determination of Compliance hand-in-hand and in the same document as its initial review and Statement of Basis for the Federal PSD Permit, although as explained above these two permits are separate legal entities governed by different legal authorities. The District incorporates that Final Determination of Compliance herein for purposes of public information, although as noted above the state-law permitting process is not being reopened at this time. The Final Determination of Compliance is attached hereto as Appendix D, and provides a detailed review of the applicable non-PSD permitting requirements.

In the context of a Federal PSD Permit review, it is important to note that the District's review found that the facility would comply with the applicable Federal New Source Performance Standards in Part 60 of Title 40 of the Code of Federal Regulations. The applicable subparts of 40 C.F.R. Part 60 include Subpart A, "General Provisions", Subpart KKKK "Standards of Performance for Stationary Combustion Turbines" and Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The proposed gas turbines and heat recovery boilers ("HRSGs") will comply with all applicable standards and limits proscribed by these regulations. The applicable emission limitations are summarized in Table 21 below:

Table 21 – Applicable New Source Performance Standards in 40 C.F.R. Part 60

Source	Section	Requirement	Compliance Verification
Gas Turbines and HRSGs	Subpart KKKK		
	40 CFR § 60.4330(a)(2)	0.060 lb SO_2/MM BTU	Sources limited by permit condition to 0.0028 lb SO_2/MM BTU maximum
	40 CFR § 60.4320 (a)	15 ppm NO_x (15% O_2)	Sources limited to 2 ppm NO_x (15% O_2)
Fire pump Diesel Engine	Subpart IIII		
	40 CFR § 60.4200 *et seq.*	7.8 nmhc+NO_x, 2.6 CO, 0.40 PM_{10} (g/HP-hr) for 2008 and earlier engines	S-6 Firepump Engine will comply with required emission limits. *See* Diesel Firepump Engine BACT Analysis.

Interested persons should also take note of the health risk screening assessment that the Air District completed under its Risk Management Policy, referenced in Section IV.B above. Under the Risk Management Policy, a health risk screening must be conducted to determine the potential impact on public health resulting from the worst-case emissions of Toxic Air Contaminants. As discussed in Section IV.B, the increased carcinogenic risk attributed to this project is less than 1.0 in one million, and the chronic hazard index and acute hazard index attributed to the emission of non-carcinogenic air contaminants are each less than 1.0. These risk levels are less than significant for project permitting purposes. The Air District reiterates these results here because they have informed the Air District's conclusions that the control technologies chosen to comply with the Federal PSD Permit requirements will not have any significant adverse ancillary environmental impacts. Please see Appendix B for further information on the Health Risk Assessment.

Another important consideration that the Air District evaluated is environmental justice. The Air District is committed to implementing its permit programs in a manner that is fair and equitable to all Bay Area residents regardless of age, culture, ethnicity, gender, race, socioeconomic status, or geographic location in order to protect against the health effects of air pollution. The Air District has worked to fulfill this commitment in the current permitting action.

The emissions from the proposed project will not cause or contribute to any significant public health impacts in the community. As described in detail above, the Air District has undertaken a detailed review of the potential public health impacts of the emissions authorized under the proposed permitting action, and has found that they will involve no significant public health risks. The risk levels involved (lifetime cancer risk of 0.7 in one million; maximum chronic Hazard Index of 0.007; and maximum acute Hazard Index of 0.024) are below what the Air District, EPA, or any other public health agency considers to be significant. The Air District has concluded that there are no significant impacts due to air emissions related to the Russell City Energy Center after all of the mitigations required by Federal and District Regulations and the California Energy Commission are implemented. There is no adverse impact on any community due to air emissions from the Russell City Energy Center and therefore there is no disparate adverse impact on an Environmental Justice community located near the facility.

VIII. PROPOSED PERMIT CONDITIONS

The Air District is proposing the following permit conditions to ensure that the proposed project will comply with all applicable Federal PSD requirements. Compliance with emissions limits will be verified by continuous emission monitors and/or periodic source tests. The proposed facility will be required to maintain records of emissions and report them to the Air District for compliance purposes.

The Air District developed the following list of proposed permit conditions as part of its integrated permit review process covering both Federal PSD and state law requirements. As such, the entire list contains some conditions required by the Federal PSD Regulation and some conditions required under state law. In some instances a permit condition may be required under both the Federal PSD Regulation and state law, for example with certain Best Available Control Technology requirements where federal and state law overlap. The requirements of the Federal PSD Regulation are those discussed in the previous sections of this document, and the proposed conditions that are being implemented pursuant to the Federal PSD Regulation are the conditions necessary to ensure compliance with the requirements discussed above. To help the reader understand which requirements are part of the proposed amended Federal PSD Permit and which are based solely on state law requirements, the state-law requirements are presented in "strike-through" format below. For a full understanding of what permit conditions are required by the Federal PSD Regulation, the reader should consult the detailed analysis of Federal PSD requirements set forth above, the Federal PSD Regulation itself, relevant decisions of the Environmental Appeals Board, and other related authorities. Permit conditions that are not being proposed pursuant the Federal PSD Regulation are not part of this proposed permitting action; persons interested in any such conditions will need to take up their concerns in the appropriate state law forum (to the extent one is available at this stage).[71]

The Air District is also providing citations to relevant authorities following certain conditions to help the reader understand the legal authority under which the Air District is proposing the condition. These citations are intended as reader aids only, and should not be considered the Air District's definitive analysis of the legal authorities underlying each condition. In particular, many conditions may be authorized by or otherwise implicate multiple legal authorities, some of which may not be listed for each condition. For a complete discussion of what permit requirements are being imposed pursuant to the Federal PSD Regulation, the reader should refer to the relevant discussions in previous sections of this document.

Russell City Energy Center
Proposed Permit Conditions

(A) Definitions:

Clock Hour:	Any continuous 60-minute period beginning on the hour
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours

[71] As noted above, the state-law permitting process has been completed and is now final. Avenues for reviewing state-law conditions have therefore been exhausted.

Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf
Rolling 3-hour period:	Any consecutive three-hour period, not including start-up or shutdown periods
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MM BTU:	million British thermal units
Gas Turbine Warm and Hot Start-up Mode:	The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d)
Gas Turbine Cold Start-up Mode:	The lesser of the first 360 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d)
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 20(b) through 20(d) until termination of fuel flow to the Gas Turbine
Gas Turbine Combustor Tuning Mode:	The period of time, not to exceed 360 minutes, in which testing, adjustment, tuning, and calibration operations are performed, as recommended by the gas turbine manufacturer, to insure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. The SCR and oxidation catalyst are not operating during the tuning operation.
Gas Turbine Cold Start-up:	A gas turbine start-up that occurs more than 48 hours after a gas turbine shutdown
Gas Turbine Hot Start-up:	A gas turbine start-up that occurs within 8 hours of a gas turbine shutdown
Gas Turbine Warm Start-up:	A gas turbine start-up that occurs between 8 hours and 48 hours of a gas turbine shutdown
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to be Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene Dibenzo[a,h]anthracene

	Indeno[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission points P-1 (combined exhaust of S-1 Gas Turbine and S-3 HRSG duct burners), P-2 (combined exhaust of S-2 Gas Turbine and S-4 HRSG duct burners), the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the RCEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems during the commissioning period
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
RCEC:	Russell City Energy Center

(B) Applicability:

Conditions 1 through 11 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 12 through 49 shall apply after the commissioning period has ended.

A. Conditions for the Commissioning Period

1. The owner/operator of the RCEC shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.
2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall tune the S-1 & S-3 Gas Turbines combustors and S-2 & S-4 Heat Recovery Steam Generators duct burners to minimize the emissions of carbon monoxide and nitrogen oxides.
3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, owner/operator shall install, adjust, and operate the A-2 & A-4 Oxidation Catalysts and A-1 & A-3 SCR Systems to minimize the emissions of carbon

monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.

4. The owner/operator of the RCEC shall submit a plan to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of S-1 & S-3 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs, and steam turbines. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the required emission control systems, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) without abatement by their respective oxidation catalysts and/or SCR Systems. The owner/operator shall not fire any of the Gas Turbines (S-1 or S-3) sooner than 28 days after the District receives the commissioning plan.
5. During the commissioning period, the owner/operator of the RCEC shall demonstrate compliance with conditions 7, 8, 9, and 10 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   firing hours
   fuel flow rates
   stack gas nitrogen oxide emission concentrations,
   stack gas carbon monoxide emission concentrations
   stack gas oxygen concentrations.

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1 & S-3), HRSGs (S-2 & S-4). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The owner/operator shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request.
6. The owner/operator shall install, calibrate, and operate the District-approved continuous monitors specified in condition 5 prior to first firing of the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4). After first firing of the turbines, the owner/operator shall adjust the detection range of these continuous emission monitors as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.
7. The owner/operator shall not fire the S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System and/or abatement of carbon monoxide emissions by A-2 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.
8. The owner/operator shall not fire the S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System and/or abatement of carbon monoxide emissions by A-4 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to

discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

9. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the Gas Turbines (S-1 & S-3), Heat Recovery Steam Generators (S-2 & S-4) and S-6 Fire Pump Diesel Engine during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 23.

10. The owner/ operator shall not operate the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) in a manner such that the combined pollutant emissions from these sources will exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1 & S-3).

NO_x (as NO_2)	4,805 pounds per calendar day	400 pounds per hour
CO	20,000 pounds per calendar day	5,000 pounds per hour
~~POC (as CH_4)~~	~~495 pounds per calendar day~~	
PM_{10}	432 pounds per calendar day	
~~SO_2~~	~~298 pounds per calendar day~~	

11. No less than 90 days after startup, the Owner/Operator shall conduct District and CEC approved source tests to determine compliance with the emission limitations specified in condition 19. The source tests shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods and shall include at least one cold start, one warm start, and one hot start. Thirty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of the source testing date.

B. Conditions for the Gas Turbines (S-1 & S-3) and the Heat Recovery Steam Generators (HRSGs; S-2 & S-4)

12. The owner/operator shall fire the Gas Turbines (S-1 & S-3) and HRSG Duct Burners (S-2 & S-4) exclusively on PUC-regulated natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. To demonstrate compliance with this limit, the operator of S-1 through S-4 shall sample and analyze the gas from each supply source at least monthly to determine the sulfur content of the gas. PG&E monthly sulfur data may be used provided that such data can be demonstrated to be representative of the gas delivered to the RCEC. In the event that the rolling 12-month annual average sulfur content exceeds 0.25 grain per 100 standard cubic feet, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions. The reduced annual heat input rate shall be subject to District review and approval. (BACT for SO_2 and PM_{10})

13. The owner/operator shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) exceeds 2,238.6 MM BTU (HHV) per hour. (PSD for NO_x)
14. The owner/operator shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) exceeds 53,726 MM BTU (HHV) per day. (PSD for PM_{10})
15. The owner/operator shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) exceeds 35,708,858 MM BTU (HHV) per year. (Offsets)
16. The owner/operator shall not fire the HRSG duct burners (S-2 & S-4) unless its associated Gas Turbine (S-1 & S-3, respectively) is in operation. (BACT for NO_x)
17. The owner/operator shall ensure that the S-1 Gas Turbine and S-2 HRSG are abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-1 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x, POC and CO)
18. The owner/operator shall ensure that the S-3 Gas Turbine and S-4 HRSG are abated by the properly operated and properly maintained A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-3 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x, POC and CO)
19. The owner/operator shall ensure that the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode. Requirements (a) through (h) do not apply during a gas turbine start-up, combustor tuning operation or shutdown. (BACT, PSD, and Regulation 2, Rule 5)
    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for S-1 Gas Turbine and S-2 HRSG after abatement by A-1 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for S-3 Gas Turbine and S-4 HRSG after abatement by A-3 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired.
    (b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)
    (c) Carbon monoxide mass emissions at P-1 and P-2 each shall not exceed 20 pounds per hour or 0.009 lb/MM BTU of natural gas fired, averaged over any rolling 3-hour period. (PSD for CO)
    (d) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 4.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)
    ~~(e) Ammonia (NH_3) emission concentrations at P-1 and P-2 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-2 and A-4 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-2 and A-4 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 29 or District approved alternative method. (Regulation 2-5)~~

(f) ~~Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.86 pounds per hour or 0.00128 lb/MM BTU of natural gas fired. (BACT)~~
(g) ~~Sulfur dioxide (SO_2) mass emissions at P-1 & P-2 each shall not exceed 6.21 pounds per hour or 0.0028 lb/MM BTU of natural gas fired. (BACT)~~
(h) Particulate matter (PM_{10}) mass emissions at P-1 & P-2 each shall not exceed 9.0 pounds per hour or 0.0040 lb PM_{10}/MM BTU of natural gas fired. (BACT)

20. The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 & S-3) during a start-up or shutdown does not exceed the limits established below. (PSD, CEC Conditions of Certification)

Pollutant	Cold Start-Up Combustor Tuning lb/start-up	Hot Start-Up lb/start-up	Warm Start-Up lb/start-up	Shutdown lb/shutdown
NO_x (as NO_2)	480.0	125	125	40
CO	5,028	2514	2514	902
~~POC (as CH_4)~~	~~83~~	~~35.3~~	~~79~~	~~16~~

21. The owner/operator shall not perform combustor tuning on Gas Turbines more than once every rolling 365 day period for each S-1 and S-3. The owner/operator shall notify the District no later than 7 days prior to combustor tuning activity. (Offsets, Cumulative Emissions)

22. The owner/operator shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any calendar day:
(a) 1,553 pounds of NO_x (as NO_2) per day (Cumulative Emissions)
(b) 1,225 pounds of NO_x per day during ozone season from June 1 to September 30. (CEC Condition of Certification)
(c) 10,774 pounds of CO per day (PSD)
(d) ~~295 pounds of POC (as CH_4) per day (Cumulative Emissions)~~
(e) 500 pounds of PM_{10} per day (PSD)
(f) ~~292 pounds of SO_2 per day (BACT)~~

23. The owner/operator shall not allow cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any consecutive twelve-month period:
(a) 134.6 tons of NO_x (as NO_2) per year (Offsets, PSD)
(b) 389.3 tons of CO per year (Cumulative Increase, PSD)
(c) ~~28.5 tons of POC (as CH_4) per year (Offsets)~~
(d) 86.8 tons of PM_{10} per year (Cumulative Increase, PSD)
(e) ~~12.2 tons of SO_2 per year (Cumulative Increase, PSD)~~

24. The owner/operator shall not allow sulfuric acid emissions (SAM) from stacks P-1 and P-2 combined to exceed 7 tons in any consecutive 12 month period. (Basis: PSD)

~~25. The owner/operator shall not allow the maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4) combined to exceed the following limits:~~

~~formaldehyde~~	~~10,912 pounds per year~~
~~benzene~~	~~226 pounds per year~~
~~Specified polycyclic aromatic hydrocarbons (PAHs)~~	~~1.8 pounds per year~~

~~unless the following requirement is satisfied:~~

~~The owner/operator shall perform a health risk assessment to determine the total facility risk using the emission rates determined by source testing and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. The owner/operator shall submit the risk analysis to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will not result in a significant cancer risk, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (Regulation 2, Rule 5)~~

26. The owner/operator shall demonstrate compliance with conditions 13 through 16, 19(a) through 19(d), 20, 22(a), 22(b), 23(a) and 23(b) by using properly operated and maintained continuous monitors (during all hours of operation including gas turbine start-up, combustor tuning, and shutdown periods) for all of the following parameters:
    (a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.
    (b) Oxygen (O_2) concentration, Nitrogen Oxides (NO_x) concentration, and Carbon Monoxide (CO) concentration at exhaust points P-1 and P-2.
    ~~(c) Ammonia injection rate at A-1 and A-3 SCR Systems~~

    The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

    The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:
    (d) Heat Input Rate for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.
    (e) Corrected NO_x concentration, NO_x mass emission rate (as NO_2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1 and P-2.

    For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 26(d) and 26(e) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(f) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(g) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3 and S-4) combined.

(h) the average NO_x mass emission rate (as NO_2), CO mass emission rate, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(i) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3 and S-4) combined.

(j) For each calendar day, the average hourly Heat Input Rates, corrected NO_x emission concentration, NO_x mass emission rate (as NO_2), corrected CO emission concentration, and CO mass emission rate for each Gas Turbine and associated HRSG combined.

(k) on a monthly basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-1, S-2, S-3 and S-4) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions ~~19(f), 19(g),~~ 19(h), 22(c), ~~22(d),~~ 22(e), ~~23(c),~~ 23(d), ~~23(e),~~ the owner/operator shall calculate and record on a daily basis, the ~~Precursor Organic Compound (POC) mass emissions,~~ Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter)~~, and Sulfur Dioxide (SO_2) mass emissions~~ from each power train. The owner/operator shall use the actual heat input rates measured pursuant to condition 26, actual Gas Turbine start-up times, actual Gas Turbine shutdown times, and CEC and District-approved emission factors developed pursuant to source testing under condition 30 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:

(a) For each calendar day, ~~POC,~~ PM_{10}~~, and SO_2~~ emissions, summarized for each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-1, S-2, S-3 & S-4) combined

(b) on a monthly basis, the cumulative total ~~POC,~~ PM_{10}~~, and SO_2~~ mass emissions, for each year for all four sources (S-1, S-2, S-3 & S-4) combined

(Offsets, PSD, Cumulative Increase)

~~28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. The owner/operator shall calculate the maximum projected annual emissions using the maximum annual heat input rate of 35,708,858 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of heat input) determined by any source test of the S-1 and S-3 Gas Turbines and/or S-2 and S-4 Heat Recovery Steam Generators. If the highest emission factor for a given pollutant occurs during minimum-load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum-load operation. The reduced annual heat input rate shall be subject to District review and approval. (Regulation 2, Rule 5)~~

~~29. Within 90 days of start-up of the RCEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 19(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-2 or A-4 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1 or P-2. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and full load modes) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. The owner/operator shall repeat the source testing on an annual basis thereafter. Ongoing compliance with condition 19(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Regulation 2, Rule 5)~~

30. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine compliance with Conditions 19(a), 19(b), 19(c), 19(d), ~~19(f), 19(g),~~ and 19(h) and while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 19(c) and 19(d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, ~~precursor organic compound concentration and mass emissions,~~ nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, ~~sulfur dioxide concentration and mass emissions, methane, ethane,~~ and particulate matter (PM_{10}) emissions including condensable particulate matter. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT, offsets)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

~~32. Within 90 days of start-up of the RCEC and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. The owner/operator shall also test the gas turbine while it is operating at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 25 for any of the compounds listed below are less than the BAAQMD trigger levels, pursuant to Regulation 2, Rule 5, shown, then the owner/operator may discontinue future testing for that pollutant:~~

	~~Benzene~~	~~≤~~	~~6.4 pounds/year and 2.9 pounds/hour~~
	~~Formaldehyde~~	~~≤~~	~~30 pounds/year and 0.21 pounds/hour~~
	~~Specified PAHs~~	~~≤~~	~~0.011 pounds/year~~

~~(Regulation 2, Rule 5)~~

33. The owner/operator shall calculate the SAM emission rate using the total heat input for the sources and the highest results of any source testing conducted pursuant to condition 30. If this SAM mass emission limit of condition #24 is exceeded, the owner/operator must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions pursuant to Regulation 2-2-306. (PSD)
34. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each gas turbine and HRSG duct burner is operating at maximum heat input rates to demonstrate compliance with the SAM emission rates specified in condition 24. The owner/operator shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (PSD)
35. The owner/operator of the RCEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)
36. The owner/operator of the RCEC shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)
37. The owner/operator of the RCEC shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)
38. The owner/operator shall ensure that the stack height of emission points P-1 and P-2 is each at least 145 feet above grade level at the stack base. (PSD, Regulation 2-5)
39. The Owner/Operator of RCEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval. (Regulation 1-501)
40. Within 180 days of the issuance of the Authority to Construct for the RCEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 29, 30, 32, 34, and 43. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Regulation 1-501)

41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the RCEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine or HRSG duct burner. (Regulation 2-6-404.1)
42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Russell City Energy Center shall submit an application for a Title IV operating permit to the BAAQMD at least 24 months before operation of any of the gas turbines (S-1, S-3, S-5, or S-7) or HRSGs (S-2, S-4, S-6, or S-8). (Regulation 2, Rule 7)
43. The owner/operator shall ensure that the Russell City Energy Center complies with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

C. Permit Conditions for Cooling Towers

44. The owner/operator shall properly install and maintain the S-5 cooling tower to minimize drift losses. The owner/operator shall equip the cooling towers with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 8,000 ppmw (mg/l). The owner/operator shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (PSD)

45. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the Russell City Energy Center, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. Within 60 days of the initial operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 44. The CEC CPM may require the owner/operator to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD)

D. Permit Conditions for S-6 Fire Pump Diesel Engine

46. The owner/operator shall not operate S-6 Fire Pump Diesel Engine more than 50 hours per year for reliability-related activities. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3)or (e)(2)(B)(3), offsets)

47. The owner/operator shall operate S-6 Fire Pump Diesel Engine only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection 9e)(2)(A)(3) or (e)(2)(B)(3))

48. The owner/operator shall operate S-6 Fire Pump Diesel Engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(G)(1), cumulative increase)

49. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.
    a. Hours of operation for reliability-related activities (maintenance and testing).
    b. Hours of operation for emission testing to show compliance with emission limits.
    c. Hours of operation (emergency).
    d. For each emergency, the nature of the emergency condition.
    e. Fuel usage for each engine(s).

    (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), cumulative increase)

IX. PROPOSED PERMIT DECISION

The Air District's Air Pollution Control Officer ("APCO") has concluded that the proposed Russell City Energy Center power plant, which is composed of the permitted sources listed below, will comply with all applicable Federal PSD Permit requirements. The APCO is therefore proposing to issue a Federal PSD Permit for the Russell City Energy Center as set forth in this document. The following sources will be subject to the proposed permit conditions discussed previously.

- S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst
- S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst
- S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst
- S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst
- S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute.
- S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input.

Pursuant to the requirements of 40 C.F.R. Part 124, the Air District's proposal to issue a Federal PSD Permit for this project is subject to public notice and an opportunity for interested members of the public to review and comment on it. Information on how the public can participate in and comment on this proposed decision is provided in Section II.D. above, and will be provided to the public by formal legal notice.

Appendix A

Greenhouse Gas (CO_2) Calculations

The following operating parameters were utilized to calculate CO_2 emissions formed from the combustion of natural gas.

ISO operating conditions, 59F[72]
Heat Input (HHV) Gas Turbine: 1,968 MMBtu/hr
Heat Input (HHV) Duct Burner: 200 MMBtu/hr
Total Heat Input each Power Block: 2,168 MMBtu/hr
Power Output: 311 MW each block/ 622 MW both blocks

Heat input rate limits for the gas turbines and HRSG are given below in **Table A-1**.

Table A-1 Maximum Allowable Heat Input Rates	
Source	**MM Btu/hour-source**
S-1 and S-3 Gas Turbines, each	2,038.6
S-1 CTG and S-2 HRSG, each power block S-3 CTG and S-4 HRSG, each power block	2238.6[a]

[a] maximum combined firing rate for each power block consisting of gas turbine and HRSG duct burner (200 MM Btu/hr)

CO_2 Emissions Calculations

For each power block:
Natural gas fuel throughput = (2,168 MMBtu/hr)/(1050 Btu/scf) = 2,064,762 scf/hr
CO_2 emissions factor[73] = 122 lb CO_2/1000 scf
CO_2 emissions = (2,064,762 scf/hr)*(122 lb CO_2/1000 scf) = 251,900 lb/hr
CO_2 emissions correlation = (251,900 lb/hr)/(2,168 MMBtu/hr) = **116.19 lb/MMBtu**

Calculate the maximum hourly emissions rate (two power blocks):
Maximum CO_2 emission rate = 1,100 lb/MW-hr
Maximum hourly CO_2 emissions = (1,100 lb/MW-hr)*622 MW **= 684,200 lbs/hr**

Calculate the maximum heat input (one power block):
Maximum Heat Input = (342,100 lbs/hr)(116.19 lb/MMBtu) = **2944.3 MMBtu/hr**

[72] From Permit Application for the Russell City Energy Center, prepared by Atmospheric Dynamics, Inc. and Tetra Tech EC, Inc., November 2006.

[73] From BAAQMD Data Bank.

Appendix B

Health Risk Assessment

As a result of: (1) combustion of natural gas at the proposed Gas Turbines and HRSGs (2) diesel fired fire pump engine and (3) the presence of dissolved solids in the cooling tower water, the proposed Russell City Energy Center Power Plant will emit the toxic air contaminants summarized in Table 6, "Maximum Facility Toxic Air Contaminant (TAC) Emissions". In accordance with the requirements of CEQA, BAAQMD Regulation 2-5, and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing the air pollutant dispersion model ISCST3 and the multi-pathway cancer risk and hazard index model ACE.

The public health impact of the carcinogenic compound emissions is quantified through the increased carcinogenic risk to the maximally exposed individual (MEI) over a 70-year exposure period. A multi-pathway risk assessment was conducted that included both inhalation and noninhalation pathways of exposure, including the mother's milk pathway. Pursuant to the BAAQMD Risk Management Policy, a project which results in an increased cancer risk to the MEI of less than one in one million over a 70-year exposure period is considered to be not significant and is therefore acceptable.

The public health impact of the noncarcinogenic compound emissions is quantified through the chronic hazard index, which is the ratio of the expected concentration of a compound to the acceptable concentration of the compound. When more than one toxic compound is emitted, the hazard indices of the compounds are summed to give the total hazard index. The acute hazard index quantifies the magnitude of the adverse health affects caused by a brief (no more than 24 hours) exposure to a chemical or group of chemicals. The chronic hazard index quantifies the magnitude of the adverse health affects from prolonged exposure to a chemical caused by the accumulation of the chemical in the human body. The worst-case assumption is made that the exposure occurs over a one-year period. Per the BAAQMD Regulation 2-5, a project with a total chronic and acute hazard index of 1.0 or less is considered to be not significant and the resulting impact on public health is deemed acceptable.

The results of the health risk assessment performed by the applicant and reviewed by the District Toxics Evaluation Section staff are summarized in **Table B-1**.

Table B-1 Health Risk Assessment Results			
Receptor	Cancer Risk (risk in one million)	Chronic Non-Cancer Hazard Index (risk in one million)	Acute Non-Cancer Hazard Index (risk in one million)
Maximally Exposed Individual	0.7	0.007	0.024
Resident	≤ 0.7	≤ 0.007	≤ 0.024
Worker	≤ 0.7	≤ 0.007	≤ 0.024

In accordance with the BAAQMD Regulation 2-5, the increased carcinogenic risk, chronic hazard index, and acute hazard index attributed to this project are each considered to be not significant since they are each less than 1.0.

Based upon the results given in Table B-1, the Russell City Energy Center project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy.

Appendix C

Summary of Air Quality Impact Analysis for the Russell City Energy Center

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE RUSSELL CITY ENERGY CENTER

December 8, 2008

BACKGROUND

Russell City Energy Center LLC has submitted a permit application (# 15487) for a proposed 600 MW combined cycle power plant, the Russell City Energy Center (RCEC). The facility is to consist of two natural gas-fired turbines with supplementary fired heat recovery steam generators, one steam turbine and supplemental burners (duct burners), a 9-cell cooling tower, and a diesel fire pump engine. The proposed project will result in an increase in air pollutant emissions of NO_2, CO, PM_{10}[74], and SO_2 triggering regulatory requirements for an air quality impact analysis.

AIR QUALITY IMPACT ANALYSIS REQUIREMENTS

Requirements for air quality impact analysis are given in 40 C.F.R. Section 52.21(k)-(o) and related authorities. The Air District has also adopted regulations on performing air quality impact analysis in its New Source Review (NSR) Rule: Regulation 2, Rule 2. These regulations provide additional guidance on performing air quality impact analyses, but do not override the EPA regulations. In the case of any inconsistency between Air District Rule 2, Regulation 2 and 40 C.F.R. Section 52.21, the federal regulations are controlling.

The criteria pollutant annual worst-case emission increases for the Project are listed in Table I, along with the corresponding significant emission rates for air quality impact analysis.

TABLE I

Comparison of proposed project's annual worst-case emissions to significant emission rates for air quality impact analysis (tons/year)

Pollutant	Proposed Project's Emissions	PSD "Major Source" Threshold Emission Rate	EPA PSD Significant Emission Rate
NO_2	134.6	100	40
CO	584.2	100	100
PM_{10}	86.8	100	15
SO_2	12.2	100	40

[74] 40 C.F.R Section 52.21(i)(1)(xi) and BAAQMD regulations require the District to use PM_{10} as a surrogate for $PM_{2.5}$ in Air Quality Impact Analyses.

Table I indicates that the proposed project emissions exceed the PSD "major source" threshold levels for nitrogen oxides (NO_2) and carbon monoxide (CO). The source is classified as a major stationary source as defined under the Federal Clean Air Act. Therefore, the air quality impact must be investigated for all pollutants emitted in quantities larger than the EPA PSD significant emission rates (shown in the last column in Table I). Table I shows that the NO_2, CO and PM_{10} ambient impacts from the project must be modeled. The detailed requirements for an air quality impact analysis for these pollutants are given in 40 C.F.R. Section 52.21, District Regulation 2, Rule 2, and EPA guidance documents.

The PSD Regulations also contain requirements for certain additional impact analyses associated with air pollutant emissions. An applicant for a permit that requires an air quality impact analysis must also, according to 40 C.F.R. Section 52.21(o) and Section 417 of the NSR Rule, provide an analysis of the impact of the source and source-related growth on visibility, soils and vegetation.

AIR QUALITY IMPACT ANALYSIS SUMMARY

The required contents of an air quality impact analysis are specified in EPA's NSR Workshop Manual and Section 414 of Regulation 2 Rule 2. According to subsection 414.1 and the NSR Workshop Manual, if the maximum air quality impacts of a new or modified stationary source do not exceed significance levels for air quality impacts, as defined in Section 2-2-233 and the NSR Workshop Manual, no further analysis is required. (Consistent with EPA regulations, it is assumed that emission increases will not interfere with the attainment or maintenance of AAQS, or cause an exceedance of a PSD increment if the resulting maximum air quality impacts are less than specified significance levels.) If the maximum impact for a particular pollutant is predicted to exceed the significance impact level, a full impact analysis is required involving estimation of background pollutant concentrations and, if applicable, a PSD increment consumption analysis. EPA also requires an analysis of any PSD source that may impact a Class I area.

Air Quality Modeling Methodology

Maximum ambient concentrations of NO_2, CO, and PM_{10} were estimated for various plume dispersion scenarios using established modeling procedures. The plume dispersion scenarios addressed include simple terrain impacts (for receptors located below stack height), complex terrain impacts (for receptors located at or above stack height), impacts due to building downwash, impacts due to inversion breakup fumigation, and impacts due to shoreline fumigation.

Emissions from the turbines and burners will be exhausted from two 145-foot exhaust stacks and the fire pump will be exhausted from a 15-foot exhaust stack. Emissions from a 9-cell cooling tower will be released at a height of 60 feet. Table II contains the emission rates used in each of the modeling scenarios: turbine startup, maximum 1-hour, maximum 8-hour, maximum 24-hour, and maximum annual average.[75] Startup conditions were modeled with both turbines in startup mode.

[75] Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. Commissioning emissions are temporary emissions that are not subject to the Air Quality Impact Analysis requirement. EPA only requires an analysis of commissioning activity impacts if it is shown that the emissions impact a Class I area or an area where a PSD increment is known to be violated. 40 C.F.R. Section 52.21(i)(3).

TABLE II
Averaging period emission rates used in modeling analysis (g/s)

Pollutant Source	Max. (1-hour)	Max. (8-hour)	Max. (24-hour)	Max. Annual Average	Start-up[a] (1-hour)	Start-up[a] (8-hour)
NO_x						
Turbine/Duct Burner 1	—	—	—	1.94	—	—
Turbine/Duct Burner 2	—	—	—	1.94	—	—
Fire Pump	—	—	—	0.00211	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—
CO						
Turbine/Duct Burner 1	2.48	1.34	—	—	169.95	80.24
Turbine/Duct Burner 2	2.48	1.34	—	—	169.95	80.24
Fire Pump	0.0275	0.0034	—	—	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—
PM_{10}						
Turbine/Duct Burner 1	—	—	1.134	1.07	—	—
Turbine/Duct Burner 2	—	—	1.134	1.07	—	—
Fire Pump	—	—	0.000417	0.0000594	—	—
Each Cooling Tower Cell (9 total))	—	—	0.0396	0.0387	—	—

[a] Start-up is the bringing of a turbine from idle status up to power production.

The EPA guideline models AERMOD (version 07026) and SCREEN3 (version 96043) were used in the air quality impacts analysis. Because an Auer land use analysis showed that the area within 3 km is classified as rural, the AERMOD option of increased surface heating due to the urban heat island was not selected.

Meteorological data was available from the Automated Surface Observing System (ASOS) at the Oakland International Airport for the years 2003-2007. The site is located 20.8 kilometers to the northwest of the RCEC. AERSURFACE (version 08009) was used to determine surface characteristics in accordance with USEPA's January 2008 "AERMOD Implementation Guide" at both the Oakland Airport and the RCEC project site. Based upon this comparison the Oakland ASOS data was considered representative of the RCEC project location and met all EPA data completeness requirements.

Upper air data for the same time period was available from the closest representative NWS radiosonde station, also the Oakland International Airport.

Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated using the Building Profile Input Program for PRIME [BPIPPRM (version 04274)]. The Ambient Ratio Methodology (with a default NO_2/NO_x

ratio of 0.75) was used for determining the annual-averaged NO_2 concentrations. Because complex terrain was located nearby, complex terrain impacts were considered. Inversion breakup fumigation and shoreline fumigation were evaluated using the SCREEN3 model.

Air Quality Modeling Results

The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts.

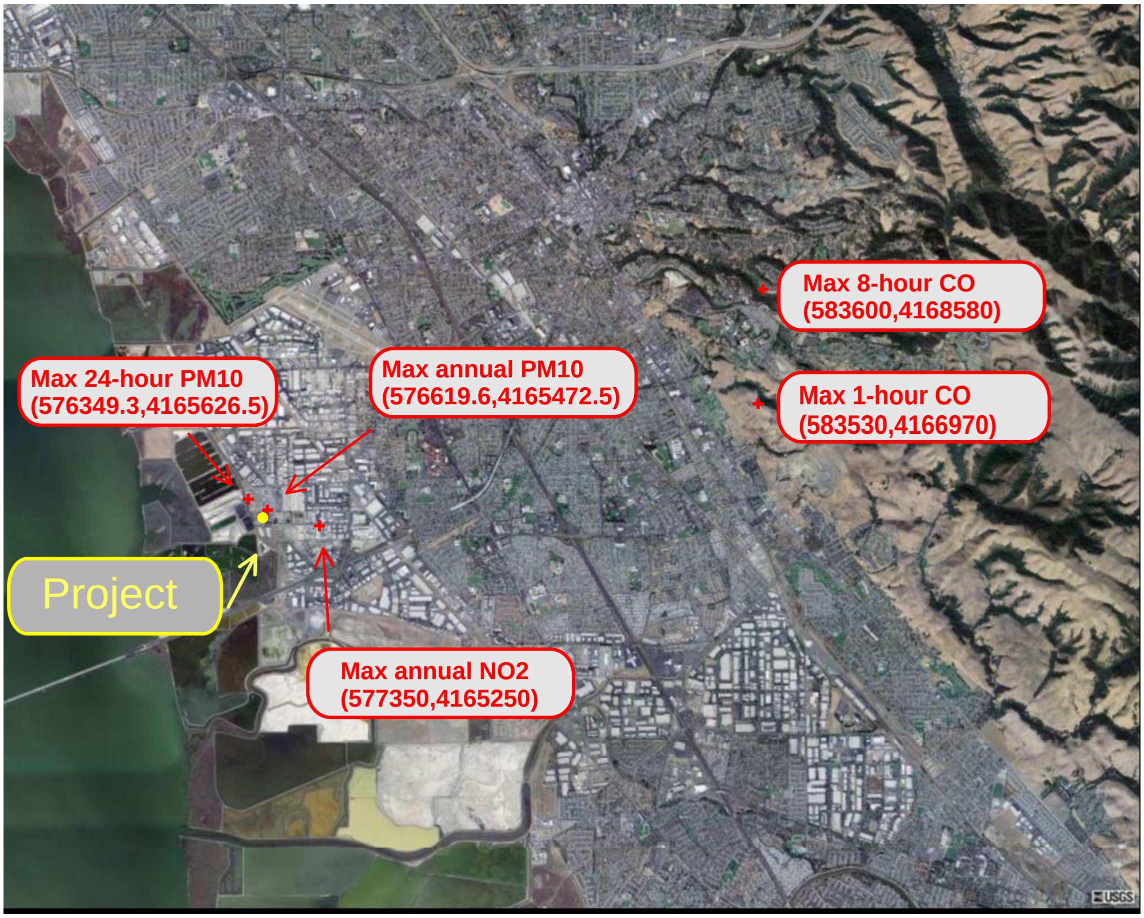
TABLE III

Maximum predicted ambient impacts of proposed project (µg/m^3)
[maximums are in bold type]

Pollutant	Averaging Time	Start-up	Inversion Break-up Fumigation Impact	Shoreline Fumigation Impact	Normal operation	Significant Air Quality Impact Level
NO_2	annual	—	—	—	**0.16**	1
CO	1-hour	**1574**	6.5	36.5	41	2000
	8-hour	**321**	—	—	5.9	500
PM_{10}	24-hour	—	2.9	3.2	**4.1**[a]	5
	annual	—	—	—	**0.72**	1

[a]Highest sixth-high 24-hour average concentration (40 C.F.R. Part 51 Appendix W Section 7.2.1.1.b)

Also shown in Table III are the corresponding significant ambient impact levels listed in the NSR Workshop Manual and Section 233 of the District's NSR Rule. In accordance with the NSR Workshop Manual and Regulation 2-2-414 further analysis is required only for the those pollutants for which the modeled impact is above the significant air quality impact level. Table III shows that there will be no impacts above the significant impact levels. No further Source Impact Analysis is required.



FI

GURE 1. Location of project maximum impacts.

CLASS I AREA IMPACT ANALYSIS

In accordance with the NSR Workshop Manual, an impact analysis must be performed for any PSD source within 100 km of a Class I area which increases air pollutant concentrations by 1 μg/m^3 or more (24-hour average) inside the Class I area. Point Reyes National Seashore is located roughly 62 km northwest of the project, and is the only Class I area within 100 km of the facility. Shown in Table IV are the results from an impact analysis using AERMOD. The table shows that the maximum 24-hour NO_2 and PM_{10} impacts within the Point Reyes National Seashore are well below the 1 μg/m^3 significance level (see Table IV).

TABLE IV

Class I 24-hour air quality impacts analysis for the Point Reyes National Seashore (μg/m^3)

Pollutant	AERMOD	Significance level	Significant
NO_2	0.06[a]	1.0	no
PM_{10}	0.06	1.0	no

[a] Assumed 100% conversion of NO_x to NO_2

ADDITIONAL IMPACTS ANALYSIS

The EPA NSR Workshop Manual states that all PSD analysis must include an additional impacts analysis. The additional impacts analysis assesses the impacts on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source and associated growth.

Visibility Impairment Analysis

Visibility impacts were assessed using both EPA's VISCREEN visibility screening model and the Calpuff model. Both analyses show that the proposed project will not cause any impairment of visibility at Point Reyes National Seashore, the closest Class I area.

Soils and Vegetation Analysis

A detailed soil inventory found in the project and impact area was prepared (Russell City Energy Center AFC, Vol. I, May, 2001 and Russell City Energy Center AFC Amendment No. 1 (01-AFC-7), November 2006.) The plant will be located on a site consisting of artificially drained soils formed from alluvium. This land is naturally high in salts, and is not designated by the California Department of Conservation as Prime Farmland or Farmland of Statewide Importance. The project is located entirely within Reyes clay drained soil type series. These soils tend to be very deep, exhibit level to nearly level topography, and are poorly to very poorly drained clays formed in tidal flats. Other soils within 2 miles of the project include Danville silty clay, Sycamore silty loam, Willows clay, Clear Lake clay and Botella silty clay. Some project area soils (Clear Lake, Danville, and Willows) are considered prime farmland soils when found in open field or agricultural areas, but none of the project facilities cross these soils in any other context than land that is zoned and used as urban, industrial land.

A detailed vegetation inventory in the project and impact area is also presented in the Russell City Energy Center AFC, Vol. I, May, 2001 and Russell City Energy Center AFC Amendment No. 1 (01-AFC-7), November 2006. Coastal habitats along the eastern shore of San Francisco Bay include salt marshes, brackish sloughs, coastal prairies, and coastal sage scrub communities. Biological resources located in the hills east of Hayward and San Leandro include Lake Chabot and Anthony Chabot Regional Park, and Garin Regional Park. Ecosystems occurring in these areas include those commonly encountered in the foothills of the Coast Ranges, such as oak woodland and valley/foothill grassland. Biological habitats within the project area consist primarily of coastal salt marsh, brackish/freshwater marsh, salt production facilities (evaporation ponds), ruderal areas, and urban landscapes with horticultural trees and shrubs. The dominant vegetation types are annual grassland and seasonal wetland dominated by saltgrass (Distichlis spicata), and alkalai heath (Frankenia salina). The only sensitive plant community found within the project area is the northern coastal salt marsh habitat. Representative species found in the salt marsh community include pickleweed (Salicornia virginica), salt grass (Distichlis spicata), and alkali heath (Frankenia salina). There are 1.68 acres of seasonal wetlands on the 14.7-acre project site. Much of the historic salt marsh community within 1 mile of the site has been altered or eliminated by urban development, sewage treatment facilities, salt evaporation ponds, and the construction of dikes and levees to prevent flooding and intrusion of saltwater. Remaining salt marsh in the project impact area includes Cogswell Marsh, managed by the East Bay Regional Park District, the Hayward Area Recreation District (HARD) marsh restoration project, and several brackish/freshwater marshes. There are no economically important terrestrial wildlife species within the impact area of the proposed project. Special environmental areas within a 1-mile radius of the project site include Cogswell Marsh, managed by the East Bay Regional Park District, the HARD marsh restoration project and Shoreline Interpretive Center, and a small section of Mt. Eden Creek.

A botanical survey was taken of the area. Table V lists the plant species observed during this survey.

TABLE V

Plant species observed during botanical surveys for the RCEC project

Family	Genus	Species/ subspecies/ variety	Common name
DICOTS			
Apiaceae	*Foeniculum*	*vulgare*	Fennel
Asteraceae	*Conyza*	*canadensis*	Horseweed
	Baccharis	*pilularis*	Coyote brush
	Cotula	*coronopifolia*	Brassbuttons
	Grindelia	*Stricta* var. *angustifolia*	Gumweed
	Sonchus	*oleraceus*	Common sow thistle
Brassicaceae	*Brassica*	*nigra*	Black mustard
Chenopodiaceae	*Chenopodium*	*album*	Lamb’s quarters
	Salicornia	*virginica*	Pickleweed
Fabaceae	*Lathyrus*	*Sp.*	Wild pea
Frankeniaceae	*Frankenia*	*salina*	Alkali heath
Geraniaceae	*Geranium*	*molle*	Wild geranium
	Erodium	*cicutarium*	Filaree
Malvaceae	*Malva*	*nicaeensis*	Bull mallow
Myrtaceae	*Eucalyptus*	*globulus*	Blue gum
Papaveraceae	*Eschscholzia*	*californica*	California poppy
Plantaginaceae	*Plantago*	*lanceolata*	English plantain
Polygonaceae	*Rumex*	*crispus*	Curly dock
Primulaceae	*Anagallis*	*arvensis*	Scarlet pimpernell
Solanaceae	*Nicotiana*	*glauca*	Tree tobacco
Urticaceae	*Urtica*	*urens*	Dwarf nettle
MONOCOTS			
Poaceae	*Avena*	*fatua*	Wild oat
	Bromus	*diandrus*	Ripgut grass
	Cortadaria	*Sp.*	Pampas grass
	Cynodon	*dactylon*	Bermuda grass
	Distichlis	*spicata*	Saltgrass
	Elymus	*sp.*	Wild-rye
	Hordeum	*murinum* ssp. *leporium*	--
	Lolium	*multiflorum*	Italian ryegrass
	Vulpia	*microstachys*	Three-week fescue
Juncaceae	*Scirpus*	*sp.*	Rush

The project maximum one-hour average NO_2, including background, is 260 μg/m^3. This concentration is below the California one-hour average NO_2 standard of 338 μg/m^3. Nitrogen dioxide is potentially phytotoxic, but generally at exposures considerably higher than those resulting from most industrial emissions. Exposures for several weeks at concentrations of 280 to 490 μg/m^{3}can cause decreases in dry weight and leaf area, but 1-hour exposures of at least 18,000 μg/m^3 are required to cause leaf damage. The maximum annual RCEC NO_2 impact is 0.16 μg/m^3. The maximum annual NO_2 background at the Fremont monitoring station between 2005 and 2007 was in 2005 at 28.2 μg/m^3. The total annual NO_2 concentration (project plus background) of 28.4 μg/m^3 is far below these threshold limits (219.0 μg/m^3). In addition, the total predicted maximum 1-hour NO_2 concentrations of 260 μg/m^3 would be significantly less than the 1-hour threshold (7,500 μg/m^3 or 3,989 ppm) for 5 percent foliar injury to sensitive vegetation (USEPA 1991, "Air Quality criteria for oxides of nitrogen").

Plants metabolize and produce carbon monoxide (CO). Soil microorganisms probably act as a buffering system and sink for CO. There are no known detrimental effects on plants due to CO concentrations of 10,000 to 230,000 μg/m^3, much higher than the RCEC 1 -hour impact of 1574 μg/m^3 (USEPA 1979, "Air Quality criteria for carbon monoxide").

A variety of plant species were exposed to CO at concentrations of 115,000 μg/m^3 to 11,500,000 μg/m^3 from 4 to 23 days (Zimmerman et al.1989, "Polymorphic regions in plant genomes detected by an M13 probe", *Genome* 32: 824-828). While practically no growth retardation was noted in plants exposed at the lower level, retarded stem elongation and leaf deformation were observed at the higher concentrations. Pea and bean seedlings also exhibited abnormal leaf formation after exposure to CO at 27,000 μg/m^3 for several days (USEPA 1979, "Air Quality criteria for carbon monoxide"). Comparatively low levels of CO in the soil have been shown to inhibit nitrogen fixation. Concentrations of 113,000 μg/m^3 have been shown to reduce nitrogen fixation, while 572,000 to 1,142,000 μg/m^3 result in nearly complete inhibition (USEPA 1979, "Air Quality criteria for carbon monoxide"). The maximum 1-hour and 8-hour CO impacts from the RCEC project and are significantly lower: the 1-hour CO concentration is 1574 μg/m^3 and the 8-hour CO concentration is 321 μg/m^3.

The deposition of airborne particulates (PM_{10}) can affect vegetation through either physical or chemical mechanisms. Physical mechanisms include the blocking of stomata so that normal gas exchange is impaired, as well as potential effects on leaf adsorption and reflectance of solar radiation. Deposition rates of 365 g/m^2/year have been shown to cause damage to fir trees, but rates of 274 g/m^2/year and 400-600 g/m^2/year did not damage vegetation at other sites (Lerman, S.L. and E.F. Darley. 1975. Particulates, pp. 141-158. In: Responses of plants to air pollution, edited by J.B. Mudd and T.T. Kozlowski. Academic Press. New York.) The maximum annual predicted concentration for PM_{10} from the RCEC is 0.72 μg/m^3. Assuming a deposition velocity of 2 cm/sec (worst-case deposition velocity, as recommended by the California Air Resources Board [CARB]), this concentration converts to an annual deposition rate of 0.45 g/m^2/year, which is several orders of magnitude below that which is expected to result in injury to vegetation (i.e., 365 g/m^2/year). The addition of the maximum predicted annual particulate deposition rate for the RCEC to three-year maximum background concentration of 19.6 μg/m^3, measured at the nearest monitoring station (Fremont) yields a total estimated particulate deposition rate of 12.8 g/m^2/year, utilizing the same 2 cm/sec deposition velocity. This total is still approximately one order of magnitude less than levels expected to result in plant injury.

EPA has established a screening procedure for determining impacts to plants, soils and animals (EPA 450/2-81-078, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," December 1980). Table 3.1 of this EPA guidance document lists screening concentrations for various pollutants, representing minimum concentrations at which adverse growth effects or tissue injuries were reported in the scientific literature. Shown in Table VI below is a comparison of the screening concentrations from the EPA document and the impacts from RCEC.

TABLE VI

Screening Assessment of RCEC impacts on soils and vegetation

Pollutant	Screening concentration[a] (µg/m^3)	Averaging period	Max. modeled impact (µg/m^3)	3-yr max. Fremont background concentration (µg/m^3)	Maximum concentration (impact plus background) (µg/m^3)	Averaging period for comparison
NO_2	3,760	4-hour	130	130	260	1-hour
	3,760	8-hour	130	130	260	1-hour
	564	1 month	130	130	260	1-hour
	94	1 year	0.16	28.2	28.4	annual
CO	1,800,000	Week	321	2245	2,873	8-hour

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

Maximum project NO_2, CO and PM_{10} concentrations would be less than the threshold levels at which scientific studies have shown a potential for negative impacts on soils and vegetation. The proposed project is not expected to have any adverse soils and vegetative impacts.

Growth Analysis

The proposed project will supply electricity to Northern California. The electricity from the new plant is expected to displace older, less efficient sources of electricity elsewhere in the region.

There will be little or no associated industrial, commercial, or residential growth as a result of this project. The electrical generating capacity from the project will be introduced into a regional electrical supply grid and therefore not stimulate local growth.

The Russell City Energy Center will have approximately 25 full-time employees (Russell City Energy Center AFC Amendment No. 1 (01-AFC-7), November 2006.) The plant is expected to begin commercial operation in the summer of 2012. The entire permanent workforce is expected to commute from within Alameda County. This is a small fraction of the total population of Oakland/Hayward/San Leandro area, which was slightly over 619,000 as of December 2008 (http://www.city-data.com/city). Facility employees are expected to come from the local workforce, regional workforce, or existing staff. There will be no significant impact on local employment. The CEC analysis of socioeconomic impacts of the Final Staff Assessment of 2007 found that "Russell

Energy Center expects that hiring construction and operation workers will occur within the East Bay/Oakland/Hayward region, and as stated above, staff agrees with this determination." Therefore, no significant growth is expected to occur as result of the project.

CONCLUSIONS

The results of the air quality impact analysis indicate that the proposed project would not interfere with the attainment or maintenance of applicable AAQS for NO_2, CO and PM_{10}. The analysis was based on EPA approved models and calculation procedures and was performed in accordance with 40 C.F.R. Section 52.21, Section 414 of the District's NSR Rule, and related guidance.

Appendix D

Amended Final Determination of Compliance, Russell City Energy Center, BAAQMD June 19, 2007

Amended
Final
Determination of Compliance

Russell City Energy Center

Bay Area Air Quality Management District
Application 15487

June 19, 2007

Weyman Lee, P.E.
Air Quality Engineer

Table of Contents

I Background

This is the amended Final Determination of Compliance (FDOC) for the Russell City Energy Center (RCEC), a 600-MW, natural-gas fired, combined-cycle merchant power plant proposed by Calpine Corporation (Calpine). The project was originally certified by the California Energy Commission in September, 2002. However, the site has been relocated approximately 1,500 feet to the north from the original location (1.24 miles east of Johnson Landing on the southeastern shore of the San Francisco Bay in the City of Hayward). Hence an amendment to the Authority to Construct is required.

The RCEC will consist of two natural gas fired Westinghouse 501F combustion turbine generators (CTGs), one steam turbine generator (STG) and associated equipment, two supplementally fired heat recovery steam generators (HRSGs), a 9-cell wet cooling tower, and a 300 hp diesel fire pump engine.

Pursuant to BAAQMD Regulation 2, Rule 3, Section 405, this document serves as the Final Determination of Compliance (FDOC) document for the RCED. It will also serve as the evaluation report for the BAAQMD Authority to Construct application number 15487.

The FDOC describes how the proposed RCEC will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

In accordance with BAAQMD Regulation 2, Rule 3, Section 404, the Preliminary Determination of Compliance (PDOC) has fulfilled the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407.

II Project Description

1. Permitted Equipment

Calpine is proposing a combined-cycle combustion turbine power generation facility with a nominal electrical output of 600 MW. As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 200 MW and the steam produced by the heat recovery steam generators (HRSGs) will feed to a steam turbine generator with a rated electrical output of 235 MW.

The RCEC will consist of the following permitted equipment:

S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst

S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute

S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input.

2. Equipment Operating Scenarios

Turbines and Heat Recovery Steam Generators

Because RCEC will be a merchant power plant, the exact operation of the new gas turbine/HRSG power trains will be dictated by market circumstances and demand. However, the following general operating modes are expected to occur at the RCEC:

Base Load: Maximum continuous output with duct firing

Load Following: Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario

Partial Shutdown: Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during periods of low overall demand such as late evening and early morning hours

Full Shutdown: May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation

The chart below outlines the maximum operating annual air pollutant emissions for this project. The carbon monoxide emissions have decreased from 584.2 tons/year to 389.3 tons/year and the PM_{10}

emissions have increased slightly from 86.4 tons/year to 86.8 tons/year. All other emission rates are unchanged from previous application #2896.

NO_2 (ton/yr)	CO (ton/yr)	POC (ton/yr)	PM_{10} (ton/yr)	SO_2 (ton/yr)
134.6	**389.3**	**28.5**	**86.8**	**12.2**

3. Air Pollution Control Strategies and Equipment

The proposed RCEC includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (NO_x), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide (SO_2), and particulate matter of less than 10 microns in diameter (PM_{10}).

a. Selective Catalytic Reduction with Ammonia Injection for the Control of NO_x

The gas turbines and HRSG duct burners each trigger BACT for NO_x emissions. The gas turbines will be equipped with dry low-NO_x (DLN) combustors, which minimize NO_x emissions by lowering peak flame temperature by premixing combustion air with a lean fuel mixture. The HRSGs will be equipped with low-NO_x duct burners, which are designed to minimize NO_x emissions. In addition, the combined NO_x emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT level NO_x emission limit of 2 ppmvd @ 15% O_2 (one hour average).

b. Oxidation Catalyst, Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to control and minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-NO_x combustors, which operate on a lean fuel mixture that minimizes incomplete combustion and CO emissions. The HRSGs will be equipped with low-NO_x duct burners which are also designed to minimize CO emissions. Furthermore, the gas turbines and HRSGs will be abated by oxidation catalysts which will oxidize the CO emissions to produce CO_2 and water. The gas turbine and HRSG duct burner combined exhaust will achieve a CO emission limit of 4 ppmvd @ 15% O_2 (three hour average).

c. Oxidation Catalyst, Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to control and minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-NO_x combustors which are designed to minimize incomplete combustion and therefore minimize POC emissions. The HRSGs will be equipped with low-NO_x burners, which are designed to minimize incomplete combustion and therefore minimize POC emissions. Furthermore, the turbines and HRSGs will be abated by oxidation catalysts which will also reduce POC emissions. The gas turbine and HRSG duct burner combined exhaust will achieve a POC emission limit of 1 ppmvd @ 15% O_2 (one hour average).

d. Exclusive Use of Clean-burning Natural gas to Minimize SO_2 and PM_{10} Emissions

The gas turbines and HRSG duct burners will burn exclusively PUC-regulated natural gas to minimize SO_2 and PM_{10} emissions. Because the SO_2 emission rate is proportional to the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of “low sulfur content” natural gas will result in the lowest possible emission of SO_2. PM_{10} emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

Table 1 Summary of Control Strategies and Emission Limitations for Gas Turbines and HRSG Duct Burners

Source	Control Strategy and Emission Limit[a]				
	NOx	**CO**	**POC**	**PM_{10}**	**SO_2**
Gas Turbine & HRSG Power Trains	DLN Combustors/SCR	DLN Combustors/ Oxidation Catalyst	DLN Combustors/ Oxidation Catalyst	PUC-Regulated Natural Gas	PUC-Regulated Natural Gas
	2 ppmv (1 hour average)	4 ppmv (3 hour average)	1 ppmv (1 hour average)	12 lb/hr	6 lb/hr

[a] ppmv concentrations dry at 15% O_2

III Facility Emissions

The facility regulated air pollutant emissions and toxic air contaminant emissions are presented in the following tables. Detailed emission calculations, including the derivations of emission factors are presented in the appendices.

Table 2 is a summary of the daily maximum regulated air pollutant emissions for the permitted sources at RCEC. These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of the District New Source Review Regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that has the potential to emit 10 pounds or more per highest day of POC, NPOC, NO_x, SO_2, PM_{10}, or CO are subject to the BACT requirement for that pollutant.

Table 2 Maximum Daily Regulated Air Pollutant Emissions for Proposed Sources (lb/day)					
	Pollutant (lb/day)				
Source	Nitrogen Oxides (as NO_2)	Carbon Monoxide	Precursor Organic Compounds	Particulate Matter (PM_{10})	Sulfur Dioxide
S-1 Gas Turbine & S-2 HRSG[a]	776	5387	148	279	146
S-3 Gas Turbine & S-4 HRSG[a]	776	5387	148	279	146
S-5 Cooling Tower[b]				68	
S-6 Fire Pump Diesel Engine[c]	2.82	0.22	0.21	0.079	0.0033

[a] NOx, CO, and POC emission rates are based upon one 360 minute cold start-up and 18 hours of Gas Turbine /HRSG full load operation at maximum combined firing rate of 2,238.6 MM BTU/hr in one day; PM_{10} and SO_2 emission rates are based upon 24 hours of Gas Turbine/HRSG baseload operation at maximum combined firing rate of 2,238.6 MM BTU/hr in one day

[b] emission rates based upon 24 hr/day operation at maximum emission rates; see Appendix B, Section 4.0 for emissions calculations

[c] emission rates based upon 1 hr/day operation at maximum emission rates

Table 3 is a summary of the maximum facility toxic air contaminant (TAC) emissions from new sources. These emissions are used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 5 ppmvd @ 15% O_2 due to ammonia slip from the A-1 and A-3 SCR Systems. The chronic and acute screening trigger levels shown are per Table 2-5.1 of Regulation 2, Rule 5.

Table 3 Maximum Facility Toxic Air Contaminant (TAC) Emissions				
Toxic Air Contaminant	Total Project Emissions (lb/yr)	Chronic Trigger Level (lb/yr-project)	Total Project Emissions (lb/hr)	Acute (1 hour max.) Trigger Level (lb/hr)
Turbines/HRSGs				
Acetaldehyde	2.33E+03	6.4E+01		
Acrolein	3.21E+02	2.3E+00	4.03E-02	4.2E-04
Ammonia	1.21E+05	7.7E+03	1.52E+01	7.1E+00
Benzene	2.26E+02	6.4E+00	2.84E-02	2.9E+00
1,3-Butadiene	2.16E+00	1.1E+00		
Ethylbenzene	3.04E+02	7.7E+04		
Formaldehyde	1.56E+04	3.0E+01	1.96E+00	2.1E-01
Hexane	4.40E+03	2.7E+05		
Naphthalene	2.82E+01	1.1E-02		
Total PAHs	1.80E+00	1.1E-02		
Propylene	1.31E+04	1.2E-02		

Table 3 Maximum Facility Toxic Air Contaminant (TAC) Emissions				
Toxic Air Contaminant	Total Project Emissions (lb/yr)	Chronic Trigger Level (lb/yr-project)	Total Project Emissions (lb/hr)	Acute (1 hour max.) Trigger Level (lb/hr)
Propylene Oxide	8.13E+02	4.9E+01	1.02E-01	6.8E+00
Toluene	1.21E+03	1.2E+01	1.51E-01	8.2E+01
Xylenes	4.08E+02	2.7E+04		
Cooling Tower				
Ammonia	1.86E+02	7.7E+03	2.12E-02	7.1E+00
Arsenic	1.55E-01	1.2E-02	1.77E-05	4.2E-04
Cadmium	2.48E-01	4.5E-02		
Hexavalent chromium	1.27E+00	1.3E-03		
Copper	1.88E+00	9.3E+01		
Lead	5.88E-01	5.4E+00	6.71E-05	2.2E-01
Manganese	2.58E+00	7.7E+00		
Mercury	1.86E-03	5.6E-01		
Nickel	1.45E+00	7.3E-01	1.66E-04	1.3E-02
Selenium	2.16E-01	7.7E+02		
Zinc	5.94E+00	1.4E+03		
Firepump Engine				
Diesel Exhaust Particulate	4.0E+00	5.8E-01		

Table 4 is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of any of the trigger levels shown must perform modeling to assess the net air quality impact of the proposed facility.

Table 4 Maximum Annual Facility Regulated Air Pollutant Emissions		
Pollutant	Permitted Source Emissions[a,b] (tons/year)	PSD Trigger[c] (tons/year)
Nitrogen Oxides (as NO_2)	134.6	100
Carbon Monoxide	389.3	100
Precursor Organic Compounds	28.5	N/A[d]
Particulate Matter (PM_{10})	86.8	100
Sulfur Dioxide[e]	12.2	100

[a] emission increases from proposed gas turbines and heat recovery steam generators, cooling tower and fire pump diesel engine; specified as permit condition limit
[b] includes start-up and shutdown emissions for gas turbines
[c] for a new major facility
[d] there is no PSD requirement for POC since the BAAQMD is designated as nonattainment for the federal 1-hour ambient air quality standard for ozone
[e] Annual emissions are calculated based on annual average sulfur content of 0.25 grain per 100 scf in natural gas

The sulfuric acid mist (H_2SO_4) emissions will be conditioned to be less than the PSD threshold of 7 tons per year. The applicant has accepted an enforceable permit condition (Number 25) limiting sulfuric acid mist from the new combustion units to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from quarterly compliance source tests. The quarterly source test will be conducted, as indicated in Condition number 34, to measure SO_2, SO_3, H_2SO_4 and ammonium sulfates. This approach is necessary because the conversion in turbines of fuel sulfur to SO_3, and then to H_2SO_4 is not well established.

IV Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed Russell City Energy Center will comply with those requirements.

A. Regulation 2, Rule 2; New Source Review

The primary requirements of New Source Review that apply to the proposed RCEC facility are Section 2-2-301; "Best Available Control Technology Requirement", Section 2-2-302; "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR", and Section 2-2-404, "PSD Air Quality Analysis".

1. Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source: or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO, or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and it must be commercially available, demonstrated to be effective and reliable on a full-scale unit, and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

Gas Turbines and HRSGs

The following section includes BACT determinations by pollutant for the gas turbines and HRSG duct burners of the proposed RCEC Project. Because each Gas Turbine and its associated HRSG will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/HRSG power train as a combined unit.

Nitrogen Oxides (NO_x)

- Combustion Gas Turbines

  District BACT Guideline 89.1.6 specifies BACT 1 (technologically feasible/cost-effective) for NO_x for a combined cycle gas turbine with a rated output $\geq$ 40 MW as 2.0 ppmvd @ 15% O_2 averaged over one hour, typically achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with dry low-NOx combustors. The EPA has accepted this BACT determination as Federal LAER. This BACT determination has been imposed on recent BAAQMD permits issued for : East Altamont Energy Center (Application #2589), and Pico Power Project (Application #6481). In addition, Palomar Energy Project located in San Diego County, a 546 MW combined cycle power plant, recently started up (4/1/06) with a NO_x emission requirement of 2.0 ppmvd, @ 15% O_2, averaged over one hour.

  A NO_x emission concentration of 2.0 ppmvd, @ 15% O_2, averaged over one hour, has been established as "achieved-in-practice" BACT for NO_x based upon our review of CEM data for the ANP Blackstone power plant, a nominal 550-MW combined cycle facility. The ANP Blackstone power plant is located in Blackstone, Massachusetts and consists of two ABB GT-4 Gas Turbines rated at 180-MW each with unfired heat recovery steam generators. We reviewed CEM data for approximately 2,313 firing hours for unit 1 and 2,737 firing hours for unit 2 which occurred from April 2001 to April 2002. With the exception of start-up and shutdown periods, the NOx concentrations were below the 2.0 ppmvd limit by a sufficient margin to demonstrate consistent, continuous compliance.
  In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.0 ppmvd NO_x @ 15% O_2, averaged over one hour during all operating modes except gas turbine start-ups and shutdowns. This meets the current District BACT 1 determination and meets or exceeds the current EPA and

ARB BACT determinations for NO_x. Compliance with this emission limitation will be achieved through the use of dry low-NOx combustors which utilize “lean-premixed” combustion technology to reduce the formation of NO_x and CO. The NO_x emissions from the turbine and HRSG will be abated through the use of a selective catalytic reduction (SCR) system with ammonia injection. The NO_x emission concentration will be verified by a CEM (continuous emissions monitor) located at the common stack for each gas turbine/HRSG power train.

- Heat Recovery Steam Generators (HRSGs)

  Supplemental heat will be supplied to the HRSGs with low-NO_x duct burners, which are designed to minimize NO_x emissions. The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve NO_x emission concentrations of less than or equal to 2.0 ppmvd @ 15% O_2, averaged over one hour.

Top-Down BACT Analysis

The following “top-down” BACT analysis for NO_x has been prepared in accordance with EPA’s 1990 Draft New Source Review Workshop Manual. A “top-down” BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. Although this analysis is based upon a controlled NOx emission concentration of 2.5 ppmv instead of the applicable NOx emission rate of 2.0 ppmv, the District has determined that the conclusions of the analysis are applicable to this project.

Available Control Options and Technical Feasibility

In a March 24, 2000 letter sent to local air pollution control districts, EPA Region 9 stated that the $SCONO_x$ Catalytic Adsorption System should be included in any BACT/LAER analysis for combined cycle gas turbine power plant projects since it can achieve the BACT/LAER emission specification for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour or 2.0 ppmvd @ 15% O_2, averaged over three hours. In this letter, EPA stated that ABB Alstom Power, the exclusive licensee for $SCONO_x$ applications, has conducted “full-scale damper testing” that demonstrates that $SCONO_x$ is technically feasible for gas turbines of the size proposed for the RCEC Project. Stone & Webster Management Consultants, Inc. of Denver, Colorado was subsequently hired by ABB to conduct an independent technical review of the $SCONO_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve unacceptable reliability and leakage problems. However, no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because the feasibility of the “scale-up” of the $SCONO_x$ system for large turbines has not been demonstrated and because the selected control technology, SCR, has been demonstrated in practice to achieve NOx emission concentrations of less than 2 ppmv, averaged over one hour, we do not consider $SCONO_x$ to be a viable control alternative for NO_x.

Although we do not consider SCONOx to be a technically feasible control alternative for this project, we have analyzed the collateral impacts of both SCR and $SCONO_x$. We are providing the following analysis for informational purposes only. The analysis shown in Table 5 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a NO_x emission rate of 25 ppmvd @ 15% O_2.

Table 5 Top-Down BACT Analysis Summary for NO_x

Control Alternative	Emissions[a] (ton/yr)	Emission Reduction[b] (ton/yr)	Total Annualized Cost[c] ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)	Toxic Impacts	Adverse Environmental Impacts	Incremental Energy Impact (MM BTU/yr)
$SCONO_x$	788	709	4,122,889	5,815	N/A[d]	No	No	122,000[e]
SCR	788	709	1,557,125	2,196	-	Yes	No	67,900[e]

[a] based upon uncontrolled NO_x emission rate of 25 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[b] based upon NO_x emission rate after abatement of 2.5 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[c] "Cost Analysis for NO_x Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999

[d] does not apply since there is no difference in emission reduction quantity between alternatives

[e] "Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

Energy Impacts

As shown in Table 5, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of $SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

Economic Impacts

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in Table 5, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of NO_x abated. However, the average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by ONSITE SYCOM Energy Corporation. Although SCONOx will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendix F for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour and therefore achieve the same NO_x emission reduction in tons per year.

Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15% O_2. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.024 and a chronic hazard index of 0.007 resulting from the emission of all non-carcinogenic compounds, including ammonia, from the gas turbines. In accordance with the District Regulation 2, Rule 5 and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter within the BAAQMD. The potential impact on the formation of secondary particulate matter in the SJVAPCD is not known. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The RCEC will utilize aqueous ammonia in a 19% (by weight) solution. Consequently, the RCEC will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases of ammonia. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed RCEC facility and found that the impact would not be significant. Therefore, the potential environmental impact due to aqueous ammonia storage at the RCEC does not justify the elimination of SCR as a control alternative.

The use of SCONOx will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

Conclusion

Both SCR and $SCONO_x$ can achieve the current accepted BACT/LAER specification for NO_x without causing significant energy, economic, or environmental impacts. Thus, neither can be eliminated as a viable control alternative. The only aspect of this analysis affected by the current NOx BACT standard of 2.0 ppmvd @ 15% O_2, averaged over one hour is the cost of compliance. The increased cost of control for each technology is not expected to affect the conclusion of this analysis. Therefore, the applicant's proposed use of SCR to meet the NO_x BACT/LAER specification is acceptable.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of two distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for CO for combined cycle gas turbines with a rated output of $\geq$ 50 MW as a CO emission concentration of $\leq$ 4.0 ppmvd @ 15% O_2. This BACT specification is based upon the Sacramento Power Authority (Campbell Soup facility) located in Sacramento County, California. BACT 1 (technologically feasible/cost-effective) is currently not specified. This emission rate limit applies to all operating modes except gas turbine start-up and shutdown.

The applicant has agreed to a CO emission limit of 4.0 ppmvd @ 15% O_2, averaged over any rolling 3-hour period. This satisfies the current BACT 2 limitation as discussed above. Compliance with this emission limitation will be achieved through the use of dry low-NOx combustors which utilize "lean-premixed" combustion technology to reduce the formation of NO_x and CO. CO emissions from the turbine and HRSG will be abated through the use of an oxidation catalyst. The CO emission concentration will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

Precursor Organic Compounds (POCs)

- Combustion Gas Turbines

There currently is no BACT 1 (technologically feasible/cost-effective) specification for POC for this source category. Currently, District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for POC for combined cycle gas turbines with an output rating $\geq$ 50 MW as 2 ppmv, dry @ 15% O_2, which is typically achieved through the use of dry-low NOx combustors and/or an oxidation catalyst. This is based upon the Delta Energy Center and Metcalf Energy Center, which were recently permitted at a POC emission limit of 2 ppmvd @ 15% O_2.

The applicant has proposed to not exceed a POC stack concentration of 1 ppmvd @ 15% O_2 with the use of dry-low NOx combustors and/or an oxidation catalyst. Thus the RCEC satisfies the BACT requirement for POC emissions.

- Heat Recovery Steam Generators (HRSGs)

The HRSG duct burners will be of low-NO_x design, which minimizes incomplete combustion and therefore the POC emission rate. Each gas turbine/HRSG pair will achieve this emission limitation through the use of dry low-NO_x burners, good combustion practices and an oxidation catalyst.

Sulfur Dioxide (SO_2)

- Combustion Gas Turbines

District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for SO_2 for combined cycle gas turbines with an output rating of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a sulfur content of $\leq$ 1.0 grains per 100 scf. This corresponds to an SO_2 emission factor of 0.0028 lb/MM BTU. The proposed turbines will burn exclusively PUC-regulated natural gas with an expected average sulfur content of 0.25 grains per 100 scf, which will result in minimal SO_2 emissions. The annual SO_2 emissions of 12.2 tons are calculated based on the annual average sulfur content. This meets the current BACT 2 specification for SO_2.

- Heat Recovery Steam Generators (HRSGs)

As is the case of the Gas Turbines, BACT for SO_2 for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a sulfur content of $\leq$ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.25 grains per 100 scf. This corresponds to an SO_2 emission factor of 0.0007 lb/MM BTU. This meets the current BACT 2 specification for SO_2.

Particulate Matter (PM_{10})

- Combustion Gas Turbines

District BACT Guideline 89.1.6 specifies BACT for PM_{10} for combined cycle gas turbines with rated output of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of $\leq$ 1.0 grains per 100 scf. The proposed turbines will utilize exclusively PUC-regulated natural gas with an average sulfur content of 0.25 gr/100 scf, which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as ammonium sulfate.

- Heat Recovery Steam Generators (HRSGs)

BACT for PM_{10} for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of ≤ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.25 grains per 100 scf which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as ammonium sulfate.

- Cooling Towers

  The BAAQMD BACT/TBACT workbook does not specify BACT for PM_{10} for wet cooling towers. However, the ARB BACT Clearinghouse cites a BACT specification for PM_{10} for the proposed La Paloma power plant cooling tower as the use of drift eliminators with a maximum drift rate of 0.0006%. The cooling towers for the Los Medanos Energy Center, Delta Energy Center, and Metcalf Energy Center are equipped with drift eliminators with a guaranteed drift rate of 0.0005%.

  The proposed Cooling Towers will also be equipped with drift eliminators with a drift rate of 0.0005%. This meets BACT for PM_{10}.

Fire Pump Diesel Engine

Based upon 24 hour per day operation under emergency conditions, the proposed fire pump diesel engine triggers BACT for NO_x, POC, and CO, since its potential to emit for each of those pollutants exceeds 10 pounds per day. The current District BACT limits and the specifications for the proposed engine are summarized in Table 6. The applicant will be required by permit conditions to select and install an engine that satisfies BACT for all pollutants listed.

Table 6 District BACT Limits and Proposed Fire Pump Diesel Engine Specifications

Pollutant	District BACT Specifications[a] (g/bhp-hr)	S-6 Engine[b] Specifications (g/bhp-hr)
NOx (as NO_2)	6.9	4.27
CO	2.75	0.33
POC	1.5	0.32
SO_2	Ultra-Low Sulfur Oil	0.005[c]
PM_{10}	Ultra-Low Sulfur Oil	0.12[c]

[a] BACT 2 ("achieved in practice") per District BACT Guideline 96.1.2, "IC Engine – Compression Ignition ≥ 175 hp output rating"
[b] emission rates specified by applicant
[c] permit conditions will require the use of ultra-low sulfur oil (15 ppm by weight) at S-6 engine

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NO_x (as NO_2) emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. For facilities that will emit more than 35 tons per year of NO_x (as NO_2), offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.2, POC offsets may be used to offset emission increases of NO_x.

It should be noted that in the case of POC and NO_x offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset.

Timing for Provision of Offsets

Pursuant to District Regulation 2-2-311, the applicant surrendered the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct on May 14, 2003. Pursuant to District Regulation 2, Rule 3, “Power Plants,” the Authority to Construct was issued after the California Energy Commission issued the Certificate for the proposed power plant.

Offset Requirements by Pollutant

The applicable offset ratios and the quantity of offsets required are summarized in Appendix C, Table C-1.

POC Offsets

Because the RCEC will emit less than 35 tons of POC per year, the POC emissions were offset at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-302.

NO_x Offsets

Because the RCEC will emit greater than 35 tons per year of Nitrogen Oxides (NO_x) from permitted sources, the applicant provided emission reduction credits (ERCs) of NO_x at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302. Pursuant to District Regulation, 2-2-302.2, the applicant provided POC ERCs to offset the proposed NO_x emission increases at a ratio of 1.15 to 1.0.

PM_{10} Offsets

Because the total PM_{10} emissions from permitted sources will not exceed 100 tons per year, the RCEC does not trigger the PM_{10} offset requirement of District Regulation 2-2-303.

SO_2 Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed SO_2 emission increases associated with this project since the facility SO_2 emissions will not exceed 100 tons per year. Regulation 2-2-303 allows for the voluntary offsetting of SO_2 emission increases of less than 100 tons per year. The applicant has opted not to provide such emission offsets.

Offset Package

Table 7 summarizes the offset obligation of the RCEC. The emission reduction credits presented in Table 7 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, "Emissions Banking", and were subsequently issued as banking certificates by the BAAQMD under the applications cited in the table footnotes. If the quantity of offsets issued under any certificate exceeded 35 tons per year for any pollutant, the application was required to fulfill the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, such applications were reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

As indicated below, Calpine has surrendered valid emission reduction credits to offset the emission increases from the permitted sources proposed for the RCEC project.

Table 7 Emission Reduction Credits Surrendered for RCEC (ton/yr)

Valid Emission Reduction Credits	POC	NO_x
Banking Certificate #, Owner[a]		
602, Calpine	41.0	2.1
687, Calpine	43.8	0.60
688, Calpine	52.3	
855, Calpine		43.5
Total ERC's Identified	137.1	46.2
Permitted Source Emission Limits	28.5	134.6
Offsets Required per BAAQMD Regulations	28.5	154.80
Outstanding Offset Balance	**+108.6[b]**	**-108.6[b]**

[a] These Banking Certificates originated from the following locations:

Certificate	Company	Location	Original Issue Date	Original Cert.
#602	Del Monte Corp	Oakland	6/6/84	#30
#602	Del Monte Corp	Oakland	9/29/87	#82
#602	Del Monte Corp	Oakland	8/1/96	#502
#687	James River Corp	San Leandro	7/20/99	#621
#688	White Cap, Inc	Hayward	7/18/00	#568
#855	PG&E	San Francisco	9/30/85	#14

Certificate #82 was generated by the shutdown of seven soldering machines (S11, 13, 15, 17, 19, 21, & 49) and 2 coating machines (S23 & S24).

Certificate #502 was generated by the shutdown of two ovens (S1 & S2), two coating operations (S3 & S4), cleaning tank (S104), and discontinued use of sealing compounds (S32 through S48) .

Certificate #621 was generated by the shutdown of 4 printing presses (S4, 6, 9, & 11), three dryers (S5, 7, & 12), and one boiler (S20).

Certificate #568 was generated by the shutdown of metal decorating applicators (S22, S22, & S33) and cold cleaner (S36).

Certificate #14 was generated by the shutdown of Potrero Units 1&2 (Boilers S-3, S-4, S-5; B&W 500,000 pounds per hour) at the Potrero Power Plant facility.

(Information for certificate #30 is not available)

[b] surplus POC credits used to offset NO_x emission increases per District Regulation 2-2-302.2

3. PSD Air Quality Impact Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts of the RCEC project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the RCEC facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards for NO_2, CO, and PM_{10} or an exceedance of any applicable PSD increment.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation. The entire PSD air quality impact analysis is contained in Appendix E.

Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit H_2SO_4 at rates in excess of 38 lb/day and 7 tons per year. However, RCEC has agreed to permit conditions limiting total facility H_2SO_4 emissions to 7 tons per year and requiring annual source testing to determine SO_2, SO_3, and H_2SO_4 emissions. If the total facility emissions ever exceed 7 tons per year, then the applicant must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions.

Table 8 Maximum Predicted Ambient Impacts of Proposed RCEC ($\mu g/m^3$) [maximums are in bold type]							
Pollutant	**Averaging Time**	**Commissioning Maximum Impact**	**Start-up**	**Inversion Break-up Fumigation Impact**	**Shoreline Fumigation Impact**	**ISCST3 Modeled Impact**	**Significant Air Quality Impact Level**
NO_2	1-hour annual	119.2 —	77 —	9.5 —	62.4 —	**226.8** **0.14**	19 1.0
CO	1-hour 8-hour	**1977** **348**	1069 178	6.5 —	36.5 —	134.7 5.7	2000 500
PM_{10}	24-hour annual	— —	— —	2.9 —	**3.2** —	2.94 **0.15**	5 1

Because the maximum modeled project impacts for annual average NO_2, 1-hour & 8-hour average CO, and 24-hour & annual average PM_{10} did not exceed their corresponding significance levels for air quality impacts per Regulation 2-2-233, further analysis to determine if the corresponding ambient air quality standards will be exceeded per District regulation 2-2-414 is not required. Table 9 summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution from the proposed RCEC for the NO_2 1-hour impact that exceeds the significance level. As shown in Table 9, the worst-case NOx emissions from RCEC will not cause or contribute to an exceedance of the California ambient air quality standard for 1-hour NO_2.

Table 9 Applicable California and National Ambient Air Quality Standards (AAQS) and Ambient Air Quality Levels from the Proposed RCEC ($\mu g/m^3$)						
Pollutant	**Averaging Time**	**Maximum Background**	**Maximum Project impact**	**Maximum Project impact plus maximum background**	**California Standards**	**National Standards**
NO_2	1-hour	143	227	370	470	---

B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be conducted to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the RCEC project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the RCEC are summarized in Table 2. In accordance with the requirements of the BAAQMD Regulation 2-5 and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing approved air pollutant dispersion models.

Table 10 Health Risk Assessment Results			
Receptor	**Cancer Risk (risk in one million)**	**Chronic Non-Cancer Hazard Index (risk in one million)**	**Acute Non-Cancer Hazard Index (risk in one million)**
Maximally Exposed Individual	0.7	0.007	0.024
Resident	≤ 0.7	≤ 0.007	≤ 0.024
Worker	≤ 0.7	≤ 0.007	≤ 0.024

The health risk assessment performed by the applicant has been reviewed by the District Toxics Evaluation Section and found to be in accordance with guidelines adopted by Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the California Air Pollution Control Officers Association (CAPCOA). Pursuant to BAAQMD Regulation 2-5, the increased carcinogenic risk attributed to this project is considered to be not significant since it is less than 1.0 in one million. The chronic hazard index and the acute hazard index attributed to the emission of non-carcinogenic air contaminants is each considered to be not significant since each is less than 1.0. Therefore, the RCEC facility is deemed to be in compliance with BAAQMD Regulation 2-5. Please see Appendix D for further discussion.

C. Other Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the PSD air quality impact analysis insures that the proposed facility will comply with this Regulation by concluding that the Russell City Energy Center will not interfere with the attainment or maintenance of applicable federal or state health-based ambient air quality standards for NO_2, CO and PM_{10}.

Regulation 2, Rule 1, Sections 301 and 302: Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, the RCEC has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1 & S-3 Gas Turbines, S-2 & S-4 Heat Recovery Steam Generators, S-5 Cooling Tower and S-6 Fire Pump Diesel Engine.

Regulation 2, Rule 1, Sections 426: CEQA-Related Information Requirements

As the lead agency under CEQA for the proposed RCEC Project, the California Energy Commission (CEC) will satisfy the CEQA requirements of Regulation 2-1-426.2.1 by producing their Final Certification which serves as an EIR-equivalent pursuant to the CEC's CEQA-certified regulatory program in accordance with CEQA Guidelines Section 15253(b) and Public Resource Code Sections 21080.5 and 25523.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-403, this Final Determination of Compliance (FDOC) serves as the APCO's decision that the proposed power plant will meet the requirements of all applicable BAAQMD, state, and federal regulations. The FDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-304, the PDOC was subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The issuance of the FDOC is not considered a final determination of whether the facility can be constructed or operated.

Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants

A risk screening analysis was performed to estimate the health risk resulting from the toxic air contaminant (TAC) emissions from the RCEC. Results from this analysis indicate that the maximally exposed individual cancer risk is estimated at 0.7 in a million, the chronic non-cancer hazard index at 0.007 in a million, and acute non-cancer hazard index at 0.024 in million. Therefore the RCEC will be in compliance the requirements of Regulation 2-5-301. Furthermore, the proposed controls are considered to be toxic best available control technology (TBACT).

Regulation 2, Rule 6: Major Facility Review

Pursuant to Regulation 2, Rule 6, section 404.1, the owner/operator of the RCEC shall submit an application to the BAAQMD for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Regulation 2-6-212.1 and 2-6-218, the RCEC will become subject to Regulation 2, Rule 6 upon completion of construction as demonstrated by first firing of the gas turbines.

Regulation 2, Rule 7: Acid Rain

The RCEC gas turbine units and heat recovery steam generators will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. Pursuant to 40 CFR Part 72.30(b)(2)(ii), RCEC must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. Pursuant to 40 CFR Part 72.2, “commence operation” includes the start-up of the unit’s combustion chamber.

Regulation 6: Particulate Matter and Visible Emissions

Through the use of dry low-NO_x burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines, HRSG duct burners, auxiliary boiler, and emergency generator set is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. As calculated in accordance with Regulation 6-310.3, the grain loading resulting from the simultaneous operation of each power train (Gas Turbine and HRSG Duct Burners) is 0.0032 gr/dscf @ 6% O_2. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 8,000 mg/l and corresponding maximum PM_{10} emission rate of 2.83 lb/hr, the proposed 9-cell cooling tower is expected to comply with the requirements of Regulation 6.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements but are subject to Regulation 6. It is expected that the conditions of certification imposed by the California Energy Commission will include requirements for construction activities that will require the use of water and/or chemical dust suppressants to minimize PM_{10} emissions and prevent visible particulate emissions.

Regulation 7: Odorous Substances

Regulation 7-302 prohibits the discharge of odorous substances which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia slip emissions from the proposed CTG/HRSG power trains will each be limited by permit condition to 5 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Organic Compounds

The gas turbines and HRSG duct burners are exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at those sources. The fire pump diesel engine will comply with Regulation 8-2-301 since its emissions will contain a total carbon concentration of less than 300 ppmv, dry.

The use of solvents for cleaning and maintenance at the RCEC is expected to comply with Regulation 8, Rule 4, "General Solvent and Surface Coating Operations" section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

Regulation 9: Inorganic Gaseous Pollutants

<u>Regulation 9, Rule 1, Sulfur Dioxide</u>
This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level SO_2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits SO_2 emissions in excess of 300 ppmv (dry). With maximum projected SO_2 emissions of < 1 ppmv, the gas turbines, HRSG duct burners, and firepimp engine are not expected to cause ground level SO_2 concentrations in excess of the limits specified in Regulation 9-1-301 and should easily comply with section 302.

<u>Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations</u>

The proposed combustion gas turbines (each rated at 2038.6 MM BTU/hr, HHV) and HRSG duct burners (each rated at 200 MM BTU/hr, HHV) shall comply with the Regulation 9-3-303 NO_x limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.0 ppmvd @ 15% O_2. The proposed fire pump diesel engine is not subject to this regulation since it has a maximum heat input rating of approximately 2.02 MM BTU/hr, based upon a maximum rated output of 300 bhp.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The proposed S-2 & S-4 HRSGs are subject to the emission concentration limits of Regulation 9, Rule 7, section 301 which limits NO_x emissions to 30 ppmv, dry @ 3% O_2 and CO emissions to 400 ppmv, dry @ 3% O_2. To determine if the HRSG duct burners comply with these NO_x emission limits, it would be necessary to install a NOx CEM upstream of the HRSG duct burners since the HRSGs and turbines exhaust through a common stack. Because the combined exhaust from the turbines and HRSGs are subject to a much more stringent BACT limit of 2.0 ppmvd @ 15% O_2, it is reasonable to conclude that the HRSG duct burners comply with the emission limits of Regulation 9, Rule 7. As a practical matter, the HRSG duct burners are therefore subject to Regulation 9, Rule 9.

Regulation 9, Rule 8, Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines

The proposed 300 hp fire pump diesel engine is exempt from Sections 301, 302 and 502 of Regulation 9, Rule 8 per Regulation 9-8-110.2, since it will be fired exclusively on diesel fuel. The proposed emergency generator will comply with Regulation 9-8-330 which allows emergency use for unlimited hours, and limits non-emergency use to 50 hours per year.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because each of the proposed combustion gas turbines will be limited by permit condition to NO_x emissions of 2.0 ppmvd @ 15% O_2, they will comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

Regulation 10: Standards of Performance for New Stationary Sources

Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60. The applicable subparts of 40 CFR Part 60 include Subpart A, "General Provisions", Subpart Da, "Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978", Subpart GG "Standards of Performance for Stationary Gas Turbines" and Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The proposed gas turbines and heat recovery steam generators comply with all applicable standards and limits proscribed by these regulations. The applicable emission limitations are summarized below:

Source	Requirement	Emission Limitation	Compliance Verification
Gas	Subpart Da		
	40 CFR 60.44a(a)(1)	0.2 lb NOx/MM BTU, except during start-up, shutdown, or malfunction	Sources limited by permit condition to 0.0074 lb/NOx/MM BTU

Turbines and HRSGs	40 CFR 60.44a(a)(2)	25% reduction of potential NOx emission concentration	SCR Systems will comply with this reduction requirement
	40 CFR 60.44a(d)(1)	1.6 lb NOx/MW-hr	0.055 lb NOx/MW-hr at nominal plant rating of 600 MW
	Subpart GG		
	40 CFR 60.332(a)(1)	100 ppmv NOx, @ 15% O_2, dry	Sources limited by permit condition to 2.0 ppmv NOx @ 15% O_2, dry
Firepump Diesel Engine	Subpart IIII		
	40 CFR 60	7.8 nmhc+NO_x, 2.6 CO, 0.40 PM_{10} (g/HP-hr) for 2008 and earlier engines	S-6 Firepump Engine will comply with required emission limits. See Table 6.

State Requirements

RCEC is subject to the Air Toxic "Hot Spots" Program contained in the California Health and Safety Code Section 44300 et seq. The facility will prepare inventory plans and reports as required.

The S-6 Firepump Engine is subject to and will be in compliance with the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines contained in Title 17 of the California Code of Regulations Section 93115. The allowable operating hours and recordkeeping requirements contained in the ATCM will be included in the Permit Conditions.

V Permit Conditions

The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb/hr and lb/MM BTU of natural gas fired) will insure that daily and annual emission rate limitations are not exceeded.

To provide maximum operational flexibility, no limitations will be imposed on the type, or quantity of gas turbine start-ups or shutdowns. Instead, the facility must comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and NO_x limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up, shutdown and combustor tuning. If the CO and NO_x CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable O_2 content and the differing response times of the O_2 and NO_x monitors, then start-up and shutdown mass emission rates will be based upon annual source test results. Compliance with POC, SO_2, and PM_{10} mass emission limits will be verified by annual source testing.

In addition to permit conditions that apply to steady-state operation of each CTG/HRSG power train, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems and/or oxidation catalysts in place. Commissioning activities include, but are not limited to the testing of the gas turbines, adjustment of control systems, and the cleaning of the HRSG steam tubes. Permit conditions 1 through 11 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedance of any applicable short-term ambient air quality standard.

Russell City Energy Center
Permit Conditions

(A) Definitions:

Clock Hour:	Any continuous 60-minute period beginning on the hour
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf
Rolling 3-hour period:	Any consecutive three-hour period, not including start-up or shutdown periods
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MM BTU:	million british thermal units
Gas Turbine Warm and Hot Start-up Mode:	The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d)
Gas Turbine Cold Start-up Mode:	The lesser of the first 360 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d)
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 20(b) through 20(d) until termination of fuel flow to the Gas Turbine
Gas Turbine Combustor Tuning Mode:	The period of time, not to exceed 360 minutes, in which testing, adjustment, tuning, and calibration operations are perfomed, as recommended by the gas turbine manufacturer, to insure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. The SCR and oxidation catalyst are not operating during the tuning operation.
Gas Turbine Cold Start-up:	A gas turbine start-up that occurs more than 48 hours after a gas turbine shutdown

Gas Turbine Hot Start-up:	A gas turbine start-up that occurs within 8 hours of a gas turbine shutdown
Gas Turbine Warm Start-up:	A gas turbine start-up that occurs between 8 hours and 48 hours of a gas turbine shutdown
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to be Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene Dibenzo[a,h]anthracene Indeno[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission points P-1 (combined exhaust of S-1 Gas Turbine and S-3 HRSG duct burners), P-2 (combined exhaust of S-2 Gas Turbine and S-4 HRSG duct burners), the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the RCEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems during the commissioning period
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
RCEC:	Russell City Energy Center

(B) Applicability:

Conditions 1 through 11 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 12 through 49 shall apply after the commissioning period has ended.

A. Conditions for the Commissioning Period

1. The owner/operator of the RCEC shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.
2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall tune the S-1 & S-3 Gas Turbines combustors and S-2 & S-4 Heat Recovery Steam Generators duct burners to minimize the emissions of carbon monoxide and nitrogen oxides.
3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, owner/operator shall install, adjust, and operate the A-2 & A-4 Oxidation Catalysts and A-1 & A-3 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.
4. The owner/operator of the RCEC shall submit a plan to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of S-1 & S-3 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs, and steam turbines. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NOx combustors, the installation and operation of the required emission control systems, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) without abatement by their respective oxidation catalysts and/or SCR Systems. The owner/operator shall not fire any of the Gas Turbines (S-1 or S-3) sooner than 28 days after the District receives the commissioning plan.
5. During the commissioning period, the owner/operator of the RCEC shall demonstrate compliance with conditions 7, 8, 9, and 10 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   firing hours
   fuel flow rates
   stack gas nitrogen oxide emission concentrations,
   stack gas carbon monoxide emission concentrations
   stack gas oxygen concentrations.

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1 & S-3), HRSGs (S-2 & S-4). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The owner/operator shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request.
6. The owner/operator shall install, calibrate, and operate the District-approved continuous monitors specified in condition 5 prior to first firing of the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4). After first firing of the turbines, the owner/operator shall adjust the detection range of these continuous emission monitors as necessary to accurately measure the resulting range of CO and NOx emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

7. The owner/operator shall not fire the S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System and/or abatement of carbon monoxide emissions by A-2 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.
8. The owner/operator shall not fire the S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System and/or abatement of carbon monoxide emissions by A-4 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.
9. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM10, and sulfur dioxide that are emitted by the Gas Turbines (S-1 & S-3), Heat Recovery Steam Generators (S-2 & S-4) and S-6 Fire Pump Diesel Engine during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 23.
10. The owner/ operator shall not operate the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) in a manner such that the combined pollutant emissions from these sources will exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1 & S-3).

NOx (as NO2)	4,805 pounds per calendar day	400 pounds per hour
CO	20,000 pounds per calendar day	5,000 pounds per hour
POC (as CH4)	495 pounds per calendar day	
PM10	432 pounds per calendar day	
SO2	298 pounds per calendar day	

11. No less than 90 days after startup, the Owner/Operator shall conduct District and CEC approved source tests to determine compliance with the emission limitations specified in condition 19. The source tests shall determine NOx, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods and shall include at least one cold start, one warm start, and one hot start. Thirty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of the source testing date.

B. Conditions for the Gas Turbines (S-1 & S-3) and the Heat Recovery Steam Generators (HRSGs; S-2 & S-4)

12. The owner/operator shall fire the Gas Turbines (S-1 & S-3) and HRSG Duct Burners (S-2 & S-4) exclusively on PUC-regulated natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. To demonstrate compliance with this limit, the operator of S-1 through S-4 shall sample and analyze the gas from each supply source at least monthly to determine the sulfur content of the gas. PG&E monthly sulfur data may be used provided that such data can be demonstrated to be representative of the gas delivered to the RCEC. In the event that the rolling 12-month annual average sulfur content exceeds 0.25 grain per 100 standard cubic feet, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions. The reduced annual heat input rate shall be subject to District review and approval. (BACT for SO2 and PM10)
13. The owner/operator shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) exceeds 2,238.6 MM BTU (HHV) per hour. (PSD for NOx)
14. The owner/operator shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) exceeds 53,726 MM BTU (HHV) per day. (PSD for PM10)
15. The owner/operator shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) exceeds 35,708,858 MM BTU (HHV) per year. (Offsets)
16. The owner/operator shall not fire the HRSG duct burners (S-2 & S-4) unless its associated Gas Turbine (S-1 & S-3, respectively) is in operation. (BACT for NOx)
17. The owner/operator shall ensure that the S-1 Gas Turbine and S-2 HRSG are abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-1 SCR catalyst bed has reached minimum operating temperature. (BACT for NOx, POC and CO)
18. The owner/operator shall ensure that the S-3 Gas Turbine and S-4 HRSG are abated by the properly operated and properly maintained A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-3 SCR catalyst bed has reached minimum operating temperature. (BACT for NOx, POC and CO)
19. The owner/operator shall ensure that the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode. Requirements (a) through (h) do not apply during a gas turbine start-up, combustor tuning operation or shutdown. (BACT, PSD, and Regulation 2, Rule 5)
    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for S-1 Gas Turbine and S-2 HRSG after abatement by A-1 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for S-3 Gas Turbine and S-4 HRSG after abatement by A-3 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired.
    (b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

(e) Carbon monoxide mass emissions at P-1 and P-2 each shall not exceed 20 pounds per hour or 0.009 lb/MM BTU of natural gas fired, averaged over any rolling 3-hour period. (PSD for CO)

(f) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 4.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)

(i) Ammonia (NH_3) emission concentrations at P-1 and P-2 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-2 and A-4 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-2 and A-4 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 29 or District approved alternative method. (Regulation 2-5)

(j) Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.86 pounds per hour or 0.00128 lb/MM BTU of natural gas fired. (BACT)

(k) Sulfur dioxide (SO_2) mass emissions at P-1 & P-2 each shall not exceed 6.21 pounds per hour or 0.0028 lb/MM BTU of natural gas fired. (BACT)

(l) Particulate matter (PM_{10}) mass emissions at P-1 & P-2 each shall not exceed 6 pounds per hour or 0.0029 lb PM_{10}/MM BTU of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1 & P-2 each shall not exceed 9 pounds per hour or 0.0038 lb PM_{10}/MM BTU of natural gas fired when the HRSG duct burners are in operation. (BACT)

20. The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 & S-3) during a start-up or shutdown does not exceed the limits established below. (PSD, CEC Conditions of Certification)

Pollutant	Cold Start-Up Combustor Tuning lb/start-up	Hot Start-Up lb/start-up	Warm Start-Up lb/start-up	Shutdown lb/shutdown
NO_x (as NO_2)	480.0	125	125	40
CO	5,028	2514	2514	902
POC (as CH_4)	83	35.3	79	16

21. The owner/operator shall not perform combustor tuning on Gas Turbines more than once every rolling 365 day period for each S-1 and S-3. The owner/operator shall notify the District no later than 7 days prior to combustor tuning activity. (Offsets, Cumulative Emissions)

22. The owner/operator shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any calendar day:

(a) 1,553 pounds of NO_x (as NO_2) per day (Cumulative Emissions)

(b) 1,225 pounds of NO_x per day during ozone season from June 1 to September 30. (CEC Condition of Certification)

(c) 10,774 pounds of CO per day (PSD)

(d)	295 pounds of POC (as CH_4) per day	(Cumulative Emissions)
(e)	626 pounds of PM_{10} per day	(PSD)
(f)	292 pounds of SO_2 per day	(BACT)

23. The owner/operator shall not allow cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any consecutive twelve-month period:

(a)	134.6 tons of NOx (as NO2) per year	(Offsets, PSD)
(b)	389.3 tons of CO per year	(Cumulative Increase, PSD)
(c)	28.5 tons of POC (as CH4) per year	(Offsets)
(d)	86.8 tons of PM10 per year	(Cumulative Increase, PSD)
(e)	12.2 tons of SO2 per year	(Cumulative Increase, PSD)

24. The owner/operator shall not allow sulfuric acid emissions (SAM) from stacks P-1 and P-2 combined to exceed 7 tons in any consecutive 12 month period. (Basis: PSD)

25. The owner/operator shall not allow the maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4) combined to exceed the following limits:

    formaldehyde 10,912 pounds per year
    benzene 226 pounds per year
    Specified polycyclic aromatic hydrocarbons (PAHs) 1.8 pounds per year

    unless the following requirement is satisfied:

    The owner/operator shall perform a health risk assessment to determine the total facility risk using the emission rates determined by source testing and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. The owner/operator shall submit the risk analysis to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will not result in a significant cancer risk, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (Regulation 2, Rule 5)

26. The owner/operator shall demonstrate compliance with conditions 13 through 16, 19(a) through 19(d), 20, 22(a), 22(b), 23(a) and 23(b) by using properly operated and maintained continuous monitors (during all hours of operation including gas turbine start-up, combustor tuning, and shutdown periods) for all of the following parameters:
    (a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.
    (b) Oxygen (O_2) concentration, Nitrogen Oxides (NO_x) concentration, and Carbon Monoxide (CO) concentration at exhaust points P-1 and P-2.
    (d) Ammonia injection rate at A-1 and A-3 SCR Systems

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(d) Heat Input Rate for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.

(e) Corrected NO_x concentration, NO_x mass emission rate (as NO_2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1 and P-2.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 26(d) and 26(e) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(f) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(g) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3 and S-4) combined.

(h) the average NO_x mass emission rate (as NO_2), CO mass emission rate, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(i) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3 and S-4) combined.

(j) For each calendar day, the average hourly Heat Input Rates, corrected NO_x emission concentration, NO_x mass emission rate (as NO_2), corrected CO emission concentration, and CO mass emission rate for each Gas Turbine and associated HRSG combined.

(k) on a monthly basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-1, S-2, S-3 and S-4) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions 19(f), 19(g), 19(h), 22(c), 22(d), 22(e), 23(c), 23(d), 23(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO_2) mass emissions from each power train. The owner/operator shall use the actual heat input rates measured pursuant to condition 26, actual Gas Turbine start-up times, actual Gas Turbine shutdown times, and CEC and District-approved emission factors developed pursuant to source testing under condition 30 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:

(a) For each calendar day, POC, PM_{10}, and SO_2 emissions, summarized for each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-1, S-2, S-3 & S-4) combined

(b) on a monthly basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all four sources (S-1, S-2, S-3 & S-4) combined

(Offsets, PSD, Cumulative Increase)

28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. The owner/operator shall calculate the maximum projected annual emissions using the maximum annual heat input rate of 35,708,858 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of heat input) determined by any source test of the S-1 and S-3 Gas Turbines and/or S-2 and S-4 Heat Recovery Steam Generators. If the highest emission factor for a given pollutant occurs during minimum-load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum-load operation. The reduced annual heat input rate shall be subject to District review and approval. (Regulation 2, Rule 5)

29. Within 90 days of start-up of the RCEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 19(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-2 or A-4 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1 or P-2. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and full load modes) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. The owner/operator shall repeat the source testing on an annual basis thereafter. Ongoing compliance with condition 19(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Regulation 2, Rule 5)

30. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine compliance with Conditions 19(a), 19(b), 19(c), 19(d), 19(f), 19(g), and 19(h) and while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 19(c) and 19(d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT, offsets)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume

V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

32. Within 90 days of start-up of the RCEC and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. The owner/operator shall also test the gas turbine while it is operating at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 25 for any of the compounds listed below are less than the BAAQMD trigger levels, pursuant to Regulation 2, Rule 5, shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	≤	6.4 pounds/year and 2.9 pounds/hour
Formaldehyde	≤	30 pounds/year and 0.21 pounds/hour
Specified PAHs	≤	0.011 pounds/year

(Regulation 2, Rule 5)

33. The owner/operator shall calculate the SAM emission rate using the total heat input for the sources and the highest results of any source testing conducted pursuant to condition 30. If this SAM mass emission limit of condition #24 is exceeded, the owner/operator must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions pursuant to Regulation 2-2-306. (PSD)
34. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each gas turbine and HRSG duct burner is operating at maximum heat input rates to demonstrate compliance with the SAM emission rates specified in condition 24. The owner/operator shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (PSD)
35. The owner/operator of the RCEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)
36. The owner/operator of the RCEC shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)
37. The owner/operator of the RCEC shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all

applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

38. The owner/operator shall ensure that the stack height of emission points P-1 and P-2 is each at least 145 feet above grade level at the stack base. (PSD, Regulation 2-5)
39. The Owner/Operator of RCEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval. (Regulation 1-501)
40. Within 180 days of the issuance of the Authority to Construct for the RCEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 29, 30, 32, 34, and 43. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Regulation 1-501)
41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the RCEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine or HRSG duct burner. (Regulation 2-6-404.1)
42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Russell City Energy Center shall submit an application for a Title IV operating permit to the BAAQMD at least 24 months before operation of any of the gas turbines (S-1, S-3, S-5, or S-7) or HRSGs (S-2, S-4, S-6, or S-8). (Regulation 2, Rule 7)

16. The owner/operator shall ensure that the Russell City Energy Center complies with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

C. Permit Conditions for Cooling Towers

43. The owner/operator shall properly install and maintain the S-5 cooling tower to minimize drift losses. The owner/operator shall equip the cooling towers with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 8,000 ppmw (mg/l). The owner/operator shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (PSD)

44. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the Russell City Energy Center, the owner/operator shall have the cooling tower vendor’s field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. Within 60 days of the initial operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM10 emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 44. The CEC CPM may require the owner/operator to perform source tests to

verify continued compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD)

D. Permit Conditions for S-6 Fire Pump Diesel Engine

45. The owner/operator shall not operate S-6 Fire Pump Diesel Engine more than 50 hours per year for reliability-related activities. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations,subsection (e)(2)(A)(3)or (e)(2)(B)(3), offsets)

46. The owner/operator shall operate S-6 Fire Pump Diesel Engine only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection 9e)(2)(A)(3) or (e)(2)(B)(3))

47. The owner/operator shall operate S-6 Fire Pump Diesel Engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(G)(1), cumulative increase)

48. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.
    a. Hours of operation for reliability-related activities (maintenance and testing).
    b. Hours of operation for emission testing to show compliance with emission limits.
    c. Hours of operation (emergency).
    d. For each emergency, the nature of the emergency condition.
    e. Fuel usage for each engine(s).

    (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), cumulative increase)

VI Recommendation

The APCO has concluded that the proposed Russell City Energy Center power plant, which is composed of the permitted sources listed below, complies with all applicable District rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst

S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute.

S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 3400 hp, 2.02 MMBtu/hr rated heat input.

Pursuant to District Regulation 2-3-404, this document is subject to the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. Accordingly, a notice inviting written public comment will be published in a newspaper of general circulation in the area of the proposed Russell City Energy Center. The public inspection and comment period will end 30 days after the date of such publication. Written comments on this document should be directed to:

Jack P. Broadbent
Executive Officer/
Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco CA 94109

Appendix A

Emission Factor Derivations

The following physical constants and standard conditions were utilized to derive the criteria-pollutant emission factors used to calculate criteria pollutant and toxic air contaminant emissions.

standard temperature[a]:	70°F
standard pressure[a]:	14.7 psia
molar volume:	385.3 dscf/lbmol
ambient oxygen concentration:	20.95%
dry flue gas factor[b]:	8740 dscf/MM Btu
natural gas higher heating value:	1050 Btu/dscf

[a] BAAQMD standard conditions per Regulation 1, Section 228.

[b] F-factor is based upon the assumption of complete stoichiometric combustion of natural gas. In effect, it is assumed that all excess air present before combustion is emitted in the exhaust gas stream. Value shown reflects the typical composition and heat content of utility-grade natural gas in San Francisco bay area.

Table A-1 summarizes the regulated air pollutant emission factors that were used to calculate mass emission rates for each source. All units are pounds per million Btu of natural gas fired based upon the high heating value (HHV). All emission factors are after abatement by applicable control equipment.

Table A-1
Controlled Regulated Air Pollutant Emission Factors for Gas Turbines and HRSGs

Pollutant	Source			
	Gas Turbine		Gas Turbine & HRSG Combined	
	lb/MM Btu	lb/hr	lb/MM Btu	lb/hr
Nitrogen Oxides (as NO_2)	0.00735[a]	14.98	0.00735[a]	16.45
Carbon Monoxide	0.0090[b]	18.24	0.0090[b]	19.96
Precursor Organic Compounds	0.00128	2.61	0.00128	2.86
Particulate Matter (PM_{10})	0.0029	6	0.0038	9
Sulfur Dioxide	0.0028	5.65	0.0028	6.21

[a] based upon stack concentration of 2.0 ppmvd NO_x @ 15% O_2 that reflects the use of dry low-NO_x combustors at the CTG, low-NO_x burners at the HRSG, and abatement by the proposed A-1 and A-3 Selective Catalytic Reduction Systems with ammonia injection.

[b] based upon the permit condition emission limit of 4 ppmvd CO @ 15% O_2.that reflects abatement by proposed A-2 and A-4 Oxidation Catalysts.

REGULATED AIR POLLUTANTS

NITROGEN OXIDE EMISSION FACTORS

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The combined NO_x emissions from the CTG and HRSG will be 2.0 ppmv, dry @ 15% O_2. This emission concentration will also apply when the HRSG duct burners are in operation. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95 - 0)/(20.95 - 15) = 7.042 ppmv NO_x, dry @ 0% O_2

(7.042/10^6)(1 lbmol/385.3 dscf)(46.01 lb NO_2/lbmol)(8740 dscf/MM Btu)

= **0.00735 lb NO_2/MM Btu**

The NO_x mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.00735 lb/MM Btu)(2038.6 MM Btu/hr) = **14.98 lb NO_x/hr**

The NO_x mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:

(0.00735 lb/MM Btu)(2238.6 MM Btu/hr) = **16.45 lb NO_x/hr**

CARBON MONOXIDE EMISSION FACTORS

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The combined CO emissions from the CTG and HRSG duct burner will be conditioned to a maximum controlled CO emission limit of 4 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The emission factor corresponding to this emission concentration is calculated as follows:

(4 ppmv)(20.95 - 0)/(20.95 - 15) = 14.08 ppmv, dry @ 0% O_2

(14.08/10^6)(lbmol/385.3 dscf)(28 lb CO/lbmol)(8740 dscf/MM Btu)

= **0.0090 lb CO/MM Btu**

The CO mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:
(0.0090 lb/MM Btu)(2038.6 MM Btu/hr) = **18.24 lb CO/hr**

The CO mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the CTG and HRSG and is calculated as follows:

(0.0090 lb/MM Btu)(2238.6 MM Btu/hr) = **19.96 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

Combustion Gas Turbine

The POC emissions from the CTG and HRSG duct burner will be conditioned to a maximum controlled emission limit of 1 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The POC emission factor corresponding to this emission concentration is calculated as follows:

(1 ppmv)(20.95 - 0)/(20.95 - 15) = 3.521 ppmv, dry @ 0% O_2

($3.521/10^6$)(lbmol/385.3 dscf)(16 lb CH_4/lbmol)(8740 dscf/MM Btu)
= **0.00128 lb POC/MM Btu**

The POC mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.00128 lb/MM Btu)(2038.6 MM Btu/hr) = **2.61 lb POC/hr**

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The POC mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the CTG and HRSG and is calculated as follows:

(0.00128 lb/MM Btu)(2238.6 MM Btu/hr) = **2.86 lb POC/hr**

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

Combustion Gas Turbine and HRSG Combined

The applicant has determined a PM_{10} emission factor of 0.00377 lb/MMBtu at maximum load for the gas turbine and HRSG. It is assumed that this PM_{10} emission factor includes secondary PM_{10} formation of particulate sulfates. The corresponding PM_{10} emission rate is:
(0.00402 lb/MMBtu)/(2238.6 MM Btu/hr) = **9 lb/hr**

The following stack data will be used to calculate the grain loading at standard conditions for full load gas turbine operation with duct burner firing to determine compliance with BAAQMD Regulation 6-310.3.

PM_{10} mass emission rate: 9 lb/hr
flow rate:4,038,946 lb/hr @ 11.8% O_2 and 180°F
moisture content:8.7% by volume

Converting flow rate to standard conditions:
(4,038,946 lb/hr)(1 hr/60 min)(385.3 cf/lb mol)(1 mol/28.39) = 915,556 acfm
(915,556 acfm)([70 + 460 ^oR]/[180 + 460 ^oR])(1 – 0.087) = 692,232 dscfm

Converting to grains/dscf:
(9 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(692,232 dscfm) = 0.00152 gr/dscf

Converting to 6% O_2 basis:
(0.00152 gr/dscf)[(20.95 - 6)/(20.95 – 11.8)] = 0.0025 gr/dscf @ 6% O_2

Combustion Gas Turbine

The PM_{10} emission factor is based upon the applicant's assumption of 3 lb/hr for the HRSG PM_{10} emission rate. The corresponding PM_{10} emission factor is therefore:
(6 lb PM_{10}/hr)/(2038.6 MM Btu/hr) = **0.0029 lb PM_{10}/MM Btu**

SULFUR DIOXIDE EMISSION FACTORS

Combustion Gas Turbine & Heat Recovery Steam Generator

The SO_2 emission factor is based upon maximum natural gas sulfur content of 1.0 grains per 100 scf and a higher heating value of 1050 Btu/scf as specified by PG&E. Although the maximum sulfur content can be as high as 1.0 grain per 100 scf, the actual sulfur content is expected be 0.25 grain per 100 scf, or less on an annual average basis.

The sulfur emission factor is calculated as follows:
(1.0 gr/100scf)(10^6 Btu/MM Btu)(2 lb SO_2/lb S)/[(7000 gr/lb)(1030 Btu/scf)(100 scf)]
= **0.0028 lb SO_2/MM Btu**

The corresponding mass SO_2 emission rate at the maximum combined firing rate of 2238.6 MM Btu/hr is:
(0.0028 lb SO_2/MM Btu)(2238.6 MM Btu/hr) = 6.21 lb/hr

The corresponding SO_2 mass emission rate at the maximum gas turbine firing rate of 2038.6 MM Btu/hr is:
(0.0028 lb SO_2/MM Btu)(2038.6 MM Btu/hr) = 5.65 lb/hr

This is converted to an emission concentration as follows:
(0.0028 lb SO_2/MM Btu)(385.3 dscf/lb-mol)(lb-mol/64.06 lb SO_2)(10^6 Btu/8740 dscf)
= 1.91 ppmvd SO_2 @ 0% O_2

which is equivalent to:
(1.91 ppmvd)(20.95 - 15)/20.95 = 0.54 ppmv SO_2, dry @ 15% O_2

Toxic Air Contaminants

The following toxic air contaminant emission factors were used to calculate worst-case emissions rates used for air pollutant dispersion models that estimate the resulting increased health risk to the maximally exposed population. To ensure that the risk is properly assessed, the emission factors are conservative and may overestimate actual emissions.

Table A-2
TAC Emission Factors[a] for Gas Turbines and HRSG Duct Burners

Contaminant	Emission Factor (lb/MM scf)
Acetaldehyde[d]	6.86E-02
Acrolein	2.37E-02
Ammonia[c]	6.63
Benzene[d]	1.36E-02
1,3-Butadiene[d]	1.27E-04
Ethylbenzene	1.79E-02
Formaldehyde[d]	9.17E-01
Hexane	2.59E-01
Naphthalene	1.66E-03
PAHs[b,d]	1.06E-04
Propylene	7.70E-01
Propylene Oxide[d]	4.78E-02
Toluene	7.10E-02
Xylene	2.61E-02

[a] California Air Toxics Emission Factors (CATEF) Database as compiled by California Air Resources Board under the Air Toxics Hotspot Program, mean values.
[b] CARB CATEF II Database does not include an emission factor for PAH. The emission rate from the most recent turbine application is used and reflects abatement by oxidation catalyst.
[c] based upon maximum allowable ammonia slip of 5 ppmv, dry @ 15% O_2 for A-1 and A-3 SCR Systems
[d] carcinogenic compound

Table A-3
TAC Emission[a] Factors Cooling Tower

Contaminant	Emission Factor (ppm)	Emission Factor (lb/hr)
Ammonia	60	2.12E-02
Arsenic	0.05	1.77E-05
Cadmium	0.08	2.83E-05
Chromium (Hex)	0.41	1.45E-04
Copper	0.61	2.15E-04
Lead	0.19	6.71E-05
Manganese	0.84	2.94E-04
Mercury	0.0006	2.12E-07

Table A-3 TAC Emission[a] Factors Cooling Tower		
Nickel	0.47	1.66E-04
Selenium	0.07	2.47E-05
Zinc	1.92	6.78E-04

[a] Based upon maximum drift loss of 353.2 lb/hr and operation of cooling tower at maximum water circulation rate of 141,252 gallons per minute.

AMMONIA EMISSION FACTOR

Combustion Gas Turbine & Heat Recovery Steam Generator

Each Gas Turbine/HRSG power train will exhaust through a common stack and be subject to a maximum ammonia exhaust concentration limit of 5 ppmvd @ 15% O_2.
(5 ppmvd)(20.95 - 0)/(20.95 - 15) = 17.61 ppmv NH_3, dry @ 0% O_2
$(17.61/10^6)$(1 lbmol/385.3 dscf)(17 lb NO_2/lbmol)(8710 dscf/MM Btu) = **0.0068 lb NH_3/MM Btu**

The NH_3 mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:
(0.0068 lb/MM Btu)(2038.6 MM Btu/hr) = **13.80 lb NH_3/hr**

The NH_3 mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:
(0.0066 lb/MM Btu)(2238.6 MM Btu/hr) = **15.15 lb NH_3/hr**

Table A-4 Regulated Air Pollutant Emission Factors for Fire Pump Diesel Engine		
	Emission Factor	
Pollutant	g/bhp-hr[a]	lb/hr[b]
Nitrogen Oxides (as NO_2)	4.27	2.82
Carbon Monoxide	0.33	0.22
Precursor Organic Compounds	0.32	0.21
Particulate Matter (PM_{10})	0.12	0.08
Sulfur Dioxide	0.005	0.003

[a] specified by applicant
[b] based upon maximum rated output of 300 bhp

Appendix B

Individual and combined heat input rate limits for the gas turbines, HRSGs, and fire pump engine are given below in **Table B-1**. These are the basis of permit conditions limiting heat input rates.

Table B-1 Maximum Allowable Heat Input Rates			
Source	**MM Btu/hour-source**	**MM Btu/day-source**	**MM Btu/year-source**
S-1 and S-3 Gas Turbines, each	2,038.6	48,926.4[a]	17,054,433[b]
S-1 CTG and S-2 HRSG, each S-3 CTG and S-4 HRSG, each	2238.6[c]	53,726[d]	17,854,429[e]
S-7 Diesel Engine	2.02	5.1[f]	101[g]

[a] based upon specified maximum rated heat input of 2038.6 MM Btu/hr and 24 hour per day operation

[b] based upon maximum fuel usage of 16,671 MMscf fuel usage per year at 1023 Btu/scf. This is equivalent to 8366 hours per year of operation. (17,054,433 Btu/yr/2038.6 MM Btu/hr)

[c] maximum combined firing rate for gas turbine and HRSG duct burners (200 MM Btu/hr)

[d] based upon maximum duct burner firing of 24 hours per day; calculated as:
(24 hr/day)(2,238.6 MM Btu/hr) = 53,726.4 MM Btu/day

[e] based upon maximum duct burner fuel usage of 782.01 MMscf fuel per year usage at 1023 Btu/scf. This is equivalent to 4000 hours per year of HRSG operation. (800,000 Btu/yr/200 MM Btu/hr)

[f] based upon maximum engine operation of 2.5 hours per day (non-emergency); calculated as:
(2.5 hr/day)(2.02 MM Btu/hr) = 5.1 MM Btu/day

[g] based upon 52 hours of non-operation operation at full load; calculated as:
(50 hr/yr)(2.02 MM Btu/hr) = 101 MM Btu/yr

B-1.0 Gas Turbine Start-Up/Turbine Tuining, and Shutdown Emission Rate Estimates

The maximum nitrogen oxide, carbon monoxide, and precursor organic compound mass emission rates from a gas turbine occur during start-up periods. The PM_{10} and sulfur dioxide emissions are a function only of fuel use rate and do not exceed typical full load emission rates during start-up. The NO_x, CO, and UHC (POC) emission rates shown in Table B-3 are specified by RCEC based upon gas turbine vendor estimates.

Table B-2 Gas Turbine Start-Up Emission Rates (lb/start-up)						
	Cold Start-Up/Combustor Tuning[a]		**Hot Start-Up[b]**		**Warm Start-Up[c]**	
Pollutant	**lb/hr**	**lb/start-up[g]**	**lb/hr**	**Lb/start-up[g]**	**lb/hr**	**lb/start-up[g]**
NO_x (as NO_2)[f]	97.2	480.0	83.8	125	97.2	125
CO[f]	1348.8	5028	1154.2	2514	1348.2	2514
UHC (as CH_4)[f]	14.9	96	14.9	44.7	14.9	48
PM_{10}[d]	10.6	63.6	10.6	31.8	10.6	31.8

Table B-2 Gas Turbine Start-Up Emission Rates (lb/start-up)						
SO_x (as SO_2)[e]	2	12	2	6	2	6

[a] cold start not to exceed six hours (360 minutes); by definition, occurs after turbine has been inoperative for at least 72 hours. Combustor tuning not to exceed six hours (360 minutes)
[b] hot start not to exceed 3 hours (180 minutes); by definition, occurs within 8 hours of a shutdown
[c] warm start not to exceed 3 hours (180 minutes); by definition occurs between 8 and 72 hours of a shutdown
[d] as a conservative estimate, based upon full load emission factor of 0.00424 lb PM_{10}/MM BTU and maximum heat input rate of 2038.6 MM BTU/hr
[e] based upon full load emission factor of 0.000693 lb SO_2/MM BTU and maximum heat input rate of 2038.6 MM BTU/hr
[f] maximum hourly emissions for NO_x, CO, and UHC provided by applicant
[g] emissions are not calculated by multiplying hourly rate by number of startup hours for NO_x, CO and UHC. These startup emissions are specified by applicant based on operational data. The startup NO_x emission limit has been adjusted from 240 lb/startup to 125 lb/startup to be consistent with CEC's conditions of certification.

Table B-3 is a comparison of baseload emission rates and shutdown emission rates specified by the applicant.

Table B-3 Gas Turbine Shutdown Emission Rates			
Pollutant	Baseload Emission Rate (lb/hr)[a]	Shutdown Emission Rate	
		lb/hr	lb/shutdown[b]
NO_x (as NO_2)	16.45	28.9	40[c]
CO	19.96	224.2	902
UHC (as CH_4)	2.86	6.7	16

[a] emission rates for gas turbine w/duct burner firing
[b] Shutdown not to exceed 30 minutes. Emissions are not calculated by multiplying hourly rate by 0.5 hours for shutdown. These emissions are specified by applicant based on operational data.
[c] The shutdown NO_x emissions limit has been adjusted from 80 lb/shutdown to 40 lb/shutdown to be consistent with CEC's conditions of certification.

B-2.0 Operating Scenarios and Regulated Air Pollutant Emissions for Gas Turbines and HRSGs

The air pollutant emission rates shown in Table B-4 were calculated in Application #2896 (original application for Authority to Construct). RCEC will be subject to the emission rates as the basis of permit condition limits and emission offset requirements. These rates are also used as inputs for the ambient air quality impact analysis. To provide maximum operational flexibility, no limitations will be imposed on the type or quantity of turbine start-ups or shutdowns. Instead, the facility must comply with rolling consecutive twelve-month mass emission limits at all times. The mass emission limits were originally based upon the emission estimates calculated for the following power plant operating envelope.

- 2,800 hours of baseload (100% load) operation per year for each gas turbine
- 5,260 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 27 hot start-ups per gas turbine per year
- 9 warm start-ups per gas turbine per year
- 12 cold start-ups per gas turbine per year

Table B-4: Maximum Annual Regulated Air Pollutant Emissions for Gas Turbines HRSGs[a], Natural Gas Engine, Fire Pump Engine, and Cooling Tower

Source (Operating Mode)	NO_2 (lb/yr)	CO (lb/yr)	POC (lb/yr)	PM_{10} (lb/yr)	SO_2 (lb/yr)
S-1 & S-3 Gas Turbines (520 hr/yr of hot start-ups)	41,600	312,693	8,320	4,680	712
S-1 & S-3 Gas Turbines (312 hr/yr of cold start-ups)	24,960	174,304	4,992	2,808	427
S-1 & S-3 Gas Turbines (13,688 total hours[a] @ 100% load)	194,506[b]	234,795[c]	33,809[c]	123,192[c]	18,753[c]
S-1 & S-3 Gas Turbines and S-2 & S-4 HRSGs (3000 total hours[a] w/duct burner firing and steam injection power augmentation)	46,950[d]	56,660[e]	8,160[e]	36,000[e]	4,530[e]
S-5 Cooling Tower				6,132[f]	
S-6 Diesel Engine[g] (30 hours per year)	117	71	14	4	3
Total Emissions (lb/yr)	308,488	778,523	55,579	172,817	24,426
(ton/yr)	**154.2[h]**	**389.3[i]**	**27.8[j]**	**86.4[k]**	**12.2**

[a] total combined firing hours for both turbines

[b] based upon the heat input rate of 1,979.4 MMBtu/hr for each gas turbine and annual average NO_2 concentration of 2.0 ppmvd (heat input rate has been revised to 2038.6 MMBtu/hr)

[c] based upon the heat input rate of 1,979.4 MM Btu/hr for each gas turbine (heat input rate has been revised to 2038.6 MMBtu/hr)

[d] based upon the maximum combined heat input rate of 2,179.4 MM Btu/hr for each CTG/HRSG power train and annual average NO_2 concentration of 2.0 ppmvd (heat input rate has been revised to 2238.6 MMBtu/hr)

[e] based upon the maximum combined heat input rate of 2,179.4 MM Btu/hr for each CTG/HRSG power train (heat input rate has been revised to 2238.6 MMBtu/hr)

[f] based upon an emission rate of 0.7 lb/hr operated 8760 hr/yr.

Circulation Rate: 135,000 gpm
Drift Rate: 0.0005%
Water Mass Rate: 67,554,000 pph
(135,000 gal/min)(60 min/hr)(8.34 lb/gal)
TDS = $0.7 \times 10^6/(67{,}554{,}000 \times 0.000005) = 2072$ ppm (maximum)

(The new cooler tower has a TDS of 8,000 ppm and an emission rate of 24,790 lb PM/yr [2.83 lb/hr X 8760 hr/yr]. The applicant is willing to be subject to maximum facility PM_{10} emissions as previously calculated)

[g] emission rates from vendor guarantee

[h] applicant elected to offset 134.6 tons of NO_x. It is specified by the applicant and is stated to reflect real operating scenarios. Permit conditions will limit total plant NO_x emissions to 134.6 tons per year

[i] adjusted from previous calculation by 4/6 for turbine CO exhaust (new BACT for turbine CO at 4 ppm from 6 ppm)

[j] applicant elected to offset 28.5 tons of POC

[k] PM_{10} emissions increased to 86.8 tons per year

B-3.0 Fire Pump Diesel Engine Emissions

Table B-5
Regulated Air Pollutant Emissions for Fire Pump Diesel Engine

Pollutant	Emission Factor		Annual Emissions[a]	
	g/bhp-hr	lb/hr	lb/yr	ton/yr
Nitrogen Oxides (as NO_2)	4.27	2.82	141	0.071
Carbon Monoxide	0.33	0.22	10.9	0.0055
Precursor Organic Compounds	0.32	0.21	10.6	0.0053
Particulate Matter (PM_{10})	0.12	0.079	3.97	0.0020
Sulfur Dioxide	0.005	0.0033	0.165	0.00008

[a] based upon 50 hours of operation per year for testing and maintenance and maximum rated output of 300 bhp

Table B-6
Worst-Case Toxic Air Contaminant Emissions for Fire Pump Diesel Engine

Toxic Air Contaminant	Emission Factor (lb/MM BTU)	Annual Emissions[a] (lb/yr)
Benzene	9.33E-04	0.0942
Toluene	4.09E-04	0.0413
Xylenes	2.85E-04	0.0288
Propylene	2.58E-03	0.2606
1,3-Butadiene	3.91E-05	0.0039
Formaldehyde	1.18E-03	0.1192
Acetaldehyde	7.67E-04	0.0775
Acrolein	9.25E-05	0.0093
Total PAHs	1.68E-04	0.0170
Diesel particulate	3.93E-02	3.97

[a] based upon assumed maximum rated heat input of 2.02 MM BTU/hr and maximum 50 operating hours per year

B-4.0 Cooling Tower PM_{10} Emissions

Cooling tower circulation rate:	141,352 gpm
maximum total dissolved solids:	8000 ppmw
Drift Loss:	353.2 lb/hr

PM_{10} = (8000 ppmw)(353.2 lb/hr)/(10^6)
= 2.83 lb/hr
= 67.8 lb/day (24 hr/day operation)
= 27,790 lb/yr (8,760 operating hours per year)
= 12.4 ton/yr

Drift Rate = (353.2 lb/hr)/(141,352 gal/min)(60 min/hr)(8.33 lb/gal) = 0.0005%

B-5.0 Worst-Case Toxic Air Contaminant (TAC) Emissions

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-1 & S-3 Gas Turbines and S-2 & S-4 HRSGs are summarized in **Table B-7**. These emission rates were used as input data for the health risk assessment modeling and are based upon a maximum annual heat input rate of 17,854,429 MM BTU per year for each gas turbine/HRSG power train. The derivation of the emission factors is detailed in Appendix A.

Table B-7
Worst-Case Annual TAC Emissions for Gas Turbines and HRSGs

Toxic Air Contaminant	Emission Factor[a] (lb/MM scf)	lb/yr-power train[b]	ton/yr
Acetaldehyde[c]	1.37E-01	2329	1.16E+00
Acrolein	1.89E-02	321.3	1.61E-01
Ammonia[d]	7.11E+00	120870	6.04E+01
Benzene[c]	1.33E-02	226.1	1.13E-01
1,3-Butadiene[c]	1.27E-04	2.16	1.08E-03
Ethylbenzene	1.79E-02	304.3	1.52E-01
Formaldehyde[c]	9.17E-01	5,456[f]	2.72E+00
Hexane	2.59E-01	4403	2.20E+00
Naphthalene	1.66E-03	28.22	1.41E-02
Propylene	7.71E-01	13107	6.55E+00
Propylene Oxide[c]	4.78E-02	812.6	4.06E-01
Toluene	7.10E-02	1207	6.04E-01
Xylenes	2.40E-02	408	2.04E-01
Total PAHs[e]	1.06E-04	1.8	9.01E-04

[a] CARB CATEF II Database emission factors, mean values
[b] from each gas turbine/HRSG power train (S-1 & S-2, S-3 & S-4); based upon annual gas usage rate of 17,000MM scf/yr-turbine/HRSG
[c] carcinogenic compounds
[d] based upon the worst-case ammonia slip from the SCR system of 5 ppmvd @ 15% O_2
[e] CARB CATEF II Database does not include an emission factor for PAH. The emission rate from the most recent turbine application is used and reflects abatement by oxidation catalyst.
[f] reflects oxidation catalyst abatement efficiency of 65% (wt) for formaldehyde

The projected toxic air contaminant emissions from S-5 Cooling Tower are summarized in **Table B-8**. The emissions are based upon a water circulation rate of 141,352 gpm and 8,760 hours of operation per year.

Table B-8 Worst-Case TAC Emissions for Cooling Tower			
Toxic Air Contaminant	**Emission Factor (lb/hr)**	**Annual Emission Rate (lb/yr)**	**(ton/yr)**
Ammonia	2.12E-02	185.71	9.29E-02
Arsenic	1.77E-05	0.16	7.75E-05
Cadmium	2.83E-05	0.25	1.24E-04
Chromium (Hex)	1.45E-04	1.27	6.35E-04
Copper	2.15E-04	1.88	9.42E-04
Lead	6.71E-05	0.59	2.94E-04
Manganese	2.94E-04	2.58	1.29E-03
Mercury	2.12E-07	0.00	9.29E-07
Nickel	1.66E-04	1.45	7.27E-04
Selenium	2.47E-05	0.22	1.08E-04
Zinc	6.78E-04	5.94	2.97E-03

B-6.0 Maximum Facility Emissions

The maximum annual facility regulated air pollutant emissions for the proposed gas turbines and HRSGs are shown in **Table B-9**. The total permitted emission rates shown below are the basis of permit condition limits and emission offset requirements, if applicable.

Table B-9 Maximum Annual Facility Regulated Air Pollutant Emissions (ton/yr)					
Source	NO_2	CO	POC	PM_{10}	SO_2
S-1 CTG and S-2 HRSG[a]	67.26	194.65	14.24	37.0	6.1
S-3 CTG and S-4 HRSG[a]	67.26	194.65	14.24	37.0	6.1
Sub-Total	**134.52**	**389.3**	**28.48**	**74.0**	**12.2**
S-5 Cooling Towers	0	0	0	12.40	0
S-6 Diesel Fire Pump Engine	0.071	0.0055	0.0053	0.002	0.00008
Total Facility Emissions	**134.6**	**389.3**	**28.5**	**86.4**	**12.2**

[a] includes gas turbine start-up/combustor tuning and shutdown emissions

Table B-10 Baseload Air Pollutant Emission Rates for Gas Turbines and HRSGs (Excluding Gas Turbine Start-up and Shutdown Emissions)					
	NO_2	CO	POC	PM_{10}	SO_2
Each Gas Turbine (2038.6 MM BTU/hr)					
lb/hr-source	14.98	18.24	2.61	8.64	6.21
lb/day-source	360	438	63	207	149
Each Gas Turbine/HRSG Power Train (2,238.6 MM BTU/hr and 24 hour per day duct burner firing					
lb/hr-power train	16.45	19.96	2.86	11.64	5.65
lb/day-power train	395	479	69	279	136

The maximum daily regulated air pollutant emissions per source including gas turbine start-up emissions are shown in **Table B-11**.

Table B-11 Maximum Daily Regulated Air Pollutant Emissions per Power Train (lb/day)					
Source (operating mode)	**NO_2**	**CO**	**POC**	**PM_{10}**	**SO_2**
Gas Turbine (6-hr cold start-up)	480	5028	96	63.6	34
Gas Turbine & HRSG (18 hours full load w/duct burner firing)	296.1	359.3	51.5	215.4	112
Total	**776**	**5387**	**148**	**279**	**146**

Table B-12 summarizes the worst-case daily regulated air pollutant emissions from permitted sources. These are the basis of permit condition daily mass emission limits. The operating scenario assumes simultaneous cold start-up of two gas turbines followed by 18 hours of full load operation with duct burner firing. Cooling tower operates 24 hours per day and the fire pump diesel engine operates for a maximum of 0.5 hours per day for exercising.

Table B-12 Worst-Case Daily Regulated Air Pollutant Facility Emissions from Permitted Sources (lb/day)					
Source (Operating Mode)	**NO_2**	**CO**	**POC**	**PM_{10}**	**SO_2**
Two Gas Turbines (6-hr cold start-up)	960	10,056	192	127.2	68
Two Gas Turbine/HRSG Power Trains (18 hours @ full load w/Duct Burner Firing)	592.2	718.6	103	430.8	224
Gas Turbine/HRSG Powertrain Sub-total	**1552**	**10,774**	**295**	**558**	**292**
S-5 Cooling Tower				68	
S-6 Diesel Fire Pump Engine	1.41	0.11	0.11	0.0017	0.04
Total	**1,553**	**10,774**	**295**	**626**	**292**

[a] daily maximum for these pollutants occur when all four turbines are operating at full load w/duct burner firing

B-7.0 Maximum Facility Emissions During Commissioning Period

Table B-13 summarizes the worst-case 1-hour and 8-hour emission rates for the RCEC during the commissioning period, when the SCR systems and oxidation catalysts are not yet installed and operational. These emission rates were used as inputs in air quality impact models that were used to determine if the RCEC would contribute to an exceedance of the 1-hour State NO_2 ambient air quality standard, the 1-hour State and Federal CO standards, and the 8-hour State and Federal CO standards during the commissioning of the gas turbines, HRSGs, and related equipment. It is assumed that only one gas turbine will be commissioned at one time.

Table B-13
Worst-Case Short-Term NO2 and CO Emission Rates for Gas Turbines during Commissioning Perioda

	NO_2	CO	POC	PM_{10}	SO_2
Both Gas Turbines	400 lb/hr	5,000 lb/hr			
Both Gas Turbines	4,805 lb/day	20,000 lb/day	495 lb/day	432 lb/day	297.6 lb/day

[a] data provide by applicant based upon data collected at the Calpine Metcalf Energy Center

B-8.0 Modeling Emission Rates

The emission rates shown in **Table B-14** were used to model the air quality impacts of the RCEC to determine compliance with State and Federal annual ambient air quality standards for NO_2, CO, and PM_{10}. A screening impact analysis of two gas turbine/HRSG duct burner systems, a 9-cell cooling tower, and a diesel fire pump engine emission rates and stack gas characteristics revealed that the worst-case impacts occur under the equipment operating scenarios listed.

TABLE B-14

Averaging Period Emission Rates Used in Modeling Analysis (g/s)

Pollutant Source	Max. (1-hour)	Commis-sioning[a] (1-hour)	Start-up[b] (1-hour)	Start-up[b] (8-hour)	Max. (8-hour)	Max. (24-hour)	Max. Annual Average
NO_x							
Turbine/Duct Burner 1	2.04	48.36	12.25	—	—	—	1.94
Turbine/Duct Burner 2	2.04	2.04	12.25	—	—	—	1.94
Fire Pump	0.36	—	—	—	—	—	0.00211
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
CO							
Turbine/Duct Burner 1	2.48	627.47	169.95	80.24	1.34	—	—
Turbine/Duct Burner 2	2.48	2.48	169.95	80.24	1.34	—	—
Fire Pump	0.0275	—	—	—	0.0034	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
PM_{10}							
Turbine/Duct Burner 1	—	—	—	—	—	1.134	1.07
Turbine/Duct Burner 2	—	—	—	—	—	1.134	1.07
Fire Pump	—	—	—	—	—	0.000417	0.0000594
Each Cooling Tower Cell (9 total))	—	—	—	—	—	0.0396	0.0387

[a] Commissioning is the original startup of a turbine and only occurs during the initial operation of the equipment after installation. Both turbines will not be commissioned at the same time.

[b] Start-up is the beginning of any of the subsequent duty cycles to bring one turbine from idle status up to power production.

Appendix C

Emission Offsets

Pursuant to District Regulation 2, Rule 2, Section 302, offsets are required for permitted sources. Emission offsets have been provided for NO_x and POC emission increases associated with S-1 Gas Turbine, S-2 HRSG, S-3 Gas Turbine, S-4 HRSG, S-5 Cooling Tower, and S-6 Diesel Engine.

Table C-1
Emission Offset Summary

	NO_2	CO	POC	PM_{10}	SO_2
BAAQMD Calculated New Source Emission Increases[a] (ton/yr)	134.6	389.3	28.5	86.4	12.2
Offset Requirement Triggered	Yes	N/A	Yes	No	No
Offset Ratio	1.15[b]	N/A	1.00[c]	N/A	N/A
Offsets Required (tons)	**154.8**	**0**	**28.5**	**0**	**0**

[a]Sum of emission increases from all permitted sources.

[b]Pursuant to District Regulation 2-2-302, the applicant must provide emission offsets at a ratio of 1.15 to 1.0 since the proposed facility NO_x emissions from permitted sources will exceed 35 tons per year.

[c]Pursuant to District Regulation 2-2-302, an offset ratio of 1.0 applies since the facility POC emissions are less than 35 tons per year.

Appendix D

Health Risk Assessment

As a result of: (1) combustion of natural gas at the proposed Gas Turbines and HRSGs (2) diesel fired fire pump engine and (3) the presence of dissolved solids in the cooling tower water, the proposed Russell City Energy Center Power Plant will emit the toxic air contaminants summarized in Table 2, "Maximum Facility Toxic Air Contaminant (TAC) Emissions". In accordance with the requirements of CEQA, BAAQMD Regulation 2-5, and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing the air pollutant dispersion model ISCST3 and the multi-pathway cancer risk and hazard index model ACE.

The public health impact of the carcinogenic compound emissions is quantified through the increased carcinogenic risk to the maximally exposed individual (MEI) over a 70-year exposure period. A multi-pathway risk assessment was conducted that included both inhalation and noninhalation pathways of exposure, including the mother's milk pathway. Pursuant to the BAAQMD Risk Management Policy, a project which results in an increased cancer risk to the MEI of less than one in one million over a 70 year exposure period is considered to be not significant and is therefore acceptable.

The public health impact of the noncarcinogenic compound emissions is quantified through the chronic hazard index, which is the ratio of the expected concentration of a compound to the acceptable concentration of the compound. When more than one toxic compound is emitted, the hazard indices of the compounds are summed to give the total hazard index. The acute hazard index quantifies the magnitude of the adverse health affects caused by a brief (no more than 24 hours) exposure to a chemical or group of chemicals. The chronic hazard index quantifies the magnitude of the adverse health affects from prolonged exposure to a chemical caused by the accumulation of the chemical in the human body. The worst-case assumption is made that the exposure occurs over a one-year period. Per the BAAQMD Regulation 2-5, a project with a total chronic and acute hazard index of 1.0 or less is considered to be not significant and the resulting impact on public health is deemed acceptable.

The results of the health risk assessment performed by the applicant and reviewed by the District Toxics Evaluation Section staff are summarized in **Table D-1**.

Table D-1 **Health Risk Assessment Results**			
Receptor	Cancer Risk (risk in one million)	Chronic Non-Cancer Hazard Index (risk in one million)	Acute Non-Cancer Hazard Index (risk in one million)
Maximally Exposed Individual	0.7	0.007	0.024
Resident	≤ 0.7	≤ 0.007	≤ 0.024
Worker	≤ 0.7	≤ 0.007	≤ 0.024

In accordance with the BAAQMD Regulation 2-5, the increased carcinogenic risk, chronic hazard index, and acute hazard index attributed to this project are each considered to be not significant since they are each less than 1.0.

Based upon the results given in Table D-1, the Russell City Energy Center project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy.

Appendix E

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE RUSSELL CITY ENERGY CENTER

February 7, 2007

BACKGROUND

Russell City Energy Center LLC has submitted a permit application (# 15487) for a proposed 600 MW combined cycle power plant, the Russell City Energy Center (RCEC). The facility is to consist of two natural gas-fired turbines with supplementary fired heat recovery steam generators, one steam turbine and supplemental burners (duct burners), a 9-cell cooling tower, and a diesel fire pump engine. The proposed project will result in an increase in air pollutant emissions of NO_2, CO, PM_{10} and SO_2 triggering regulatory requirements for an air quality impact analysis.

AIR QUALITY IMPACT ANALYSIS REQUIREMENTS

Requirements for air quality impact analysis are given in the District's New Source Review (NSR) Rule: Regulation 2, Rule 2.

The criteria pollutant annual worst case emission increases for the Project are listed in Table I, along with the corresponding significant emission rates for air quality impact analysis.

TABLE 1
Comparison of proposed project's annual worst case emissions to significant emission rates for air quality impact analysis

Pollutant	Proposed Project's Emissions (tons/year)	Significant Emission Rate (tons/year) (Reg-2-2-304 to 2-2-306)	EPA PSD Significant Emission Rates for major stationary sources (tons/year)
NO_x	134.6	100	40
CO	584.2	100	100
PM_{10}	86.8	100	15
SO_2	12.2	100	40

Table I indicates that the proposed project emissions exceed District significant emission levels for nitrogen oxides (NO_x), carbon monoxide (CO), and respirable particulate matter (PM_{10}). The source is classified as a major stationary source as defined under the Federal Clean Air Act. Therefore, the air quality impact must be investigated for all pollutants emitted in quantities larger than the EPA PSD significant emission rates (shown in the last column in Table I). Table I shows that the NO_2, CO and PM_{10} ambient impacts from the project must be modeled. The detailed requirements for an air quality impact analysis for these pollutants are given in Sections 304, 305 and 306 of the District's NSR Rule and 40 CFR 51.166 of the Code of Federal Regulations.

The District's NSR Rule also contains requirements for certain additional impact analyses associated with air pollutant emissions. An applicant for a permit that requires an air quality impact analysis must also, according to Section 417 of the NSR Rule, provide an analysis of the impact of the source and source-related growth on visibility, soils and vegetation.

AIR QUALITY IMPACT ANALYSIS SUMMARY

The required contents of an air quality impact analysis are specified in Section 414 of Regulation 2 Rule 2. According to subsection 414.1, if the maximum air quality impacts of a new or modified stationary source do not exceed significance levels for air quality impacts, as defined in Section 2-2-233, no further analysis is required. (Consistent with EPA regulations, it is assumed that emission increases will not interfere with the attainment or maintenance of AAQS, or cause an exceedance of a PSD increment if the resulting maximum air quality impacts are less than specified significance levels). If the maximum impact for a particular pollutant is predicted to exceed the significance impact level, a full impact analysis is required involving estimation of background pollutant concentrations and, if applicable, a PSD increment consumption analysis. EPA also requires a Class I increment analysis of any PSD source which increases NO_2 or PM_{10} concentrations by 1 $\mu g/m^3$ or more (24-hour average) in a Class I area.

Air Quality Modeling Methodology

Maximum ambient concentrations of NO_2, CO and PM_{10} were estimated for various plume dispersion scenarios using established modeling procedures. The plume dispersion scenarios addressed include simple terrain impacts (for receptors located below stack height), complex terrain impacts (for receptors located at or above stack height), impacts due to building downwash, impacts due to inversion breakup fumigation, and impacts due to shoreline fumigation.

Emissions from the turbines and burners will be exhausted from two 145 foot exhaust stacks and the fire pump will be exhausted from a 15 foot exhaust stack. Emissions from a 9-cell cooling tower will be released at a height of 60 feet. Table II contains the emission rates used in each of the modeling scenarios: turbine commissioning, turbine startup, maximum 1-hour, maximum 8-hour, maximum 24-hour, and maximum annual average. Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. Startup conditions were modeled with one turbine in startup mode, while the other turbine was in normal operation.

The EPA models SCREEN3 and ISCST3 were used in the air quality impacts analysis. A land use analysis showed that the rural dispersion coefficients were required for the analysis. The models were run using five years of meteorological data (1990 through 1994) collected approximately 6.6 km southeast of the project at the BAAQMD's Union City meteorological monitoring station. Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. Using 1990-1994 San Leandro ozone monitoring data, the Ozone Limiting Method was employed to convert one-hour NO_x impacts into one-hour NO_2 impacts. (The San Leandro monitoring station is located 8.8 km north of the project) The Ambient Ratio Methodology (with a default NO_2/NO_x ratio of 0.75) was used for determining the annual-averaged NO_2 concentrations. Because complex terrain was located nearby, complex terrain impacts were considered. Inversion breakup fumigation and shoreline fumigation were evaluated using the SCREEN3 model.

TABLE 2
Averaging period emission rates used in modeling analysis (g/s)

Pollutant Source	Max. (1-hour)	Commis-sioning[1] (1-hour)	Start-up[2] (1-hour)	Start-up[2] (8-hour)	Max. (8-hour)	Max. (24-hour)	Max. Annual Average
NO_x							
Turbine/Duct Burner 1	2.04	48.36	12.25	—	—	—	1.94
Turbine/Duct Burner 2	2.04	2.04	12.25	—	—	—	1.94
Fire Pump	0.36	—	—	—	—	—	0.00211
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
CO							
Turbine/Duct Burner 1	2.48	627.47	169.95	80.24	1.34	—	—
Turbine/Duct Burner 2	2.48	2.48	169.95	80.24	1.34	—	—
Fire Pump	0.0275	—	—	—	0.0034	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
PM_{10}							
Turbine/Duct Burner 1	—	—	—	—	—	1.134	1.07
Turbine/Duct Burner 2	—	—	—	—	—	1.134	1.07
Fire Pump	—	—	—	—	—	0.000417	0.0000594
Each Cooling Tower Cell (9 total))	—	—	—	—	—	0.0396	0.0387

[1]Commissioning is the original startup of a turbine and only occurs during the initial operation of the equipment after installation. Both turbines will not be commissioned at the same time. [2]Start-up is the beginning of any of the subsequent duty cycles to bring one turbine from idle status up to power production.

Air Quality Modeling Results

The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts.

Also shown in Table III are the corresponding significant ambient impact levels listed in Section 233 of the District's NSR Rule. In accordance with Regulation 2-2-414 further analysis is required only for the those pollutants for which the modeled impact is above the significant air quality impact level. Table III shows that the only impact requiring further analysis is the 1-hour NO_2 modeled impact.

Pollutant	Averagin g Time	Commissioning Maximum Impact	Start-up	Inversion Break-up Fumigation Impact	Shoreline Fumigation Impact	ISCST3 Modeled Impact	Significant Air Quality Impact Level
NO_2	1-hour	119.2	77	9.5	62.4	**226.8**	19
	annual	—	—	—	—	**0.14**	1.0
CO	1-hour	**1977**	1069	6.5	36.5	134.7	2000
	8-hour	**348**	178	—	—	5.7	500
PM_{10}	24-hour	—	—	2.9	**3.2**	2.94	5
	annual	—	—	—	—	**0.15**	1

TABLE 3
Maximum predicted ambient impacts of proposed project (μg/m^3)
[maximums are in bold type]

Background Air Quality Levels

Regulation 2-2-111 entitled "Exemption, PSD Monitoring," exempts an applicant from the requirement of monitoring background concentrations in the impact area (section 414.3) provided the impacts from the proposed project are less than specified levels. Table IV lists the applicable exemption standard and the maximum impact from the proposed facility. As shown, the modeled NO2 impact is well below the preconstruction monitoring threshold.

TABLE 4
PSD monitoring exemption level and maximum impact from the proposed project for NO_2 (μg/m^3)

Pollutant	Averaging Time	Exemption Level	Maximum Impact from Proposed Project
NO_2	annual	14	0.14

The District-operated Fremont-Chapel Way Monitoring Station, located 18.3 km southeast of the project, was chosen as representative of background NO_2 concentrations. Table V contains the concentrations measured at the site for the past 5 years (1996 through 2000).

TABLE 5
Background NO_2 ($\mu g/m^3$) at Fremont-Chapel Way Monitoring Station for the past three years (maximum is in bold type)

	NO_2
Year	Highest 1-hour average
2003	**143**
2004	113
2005	130

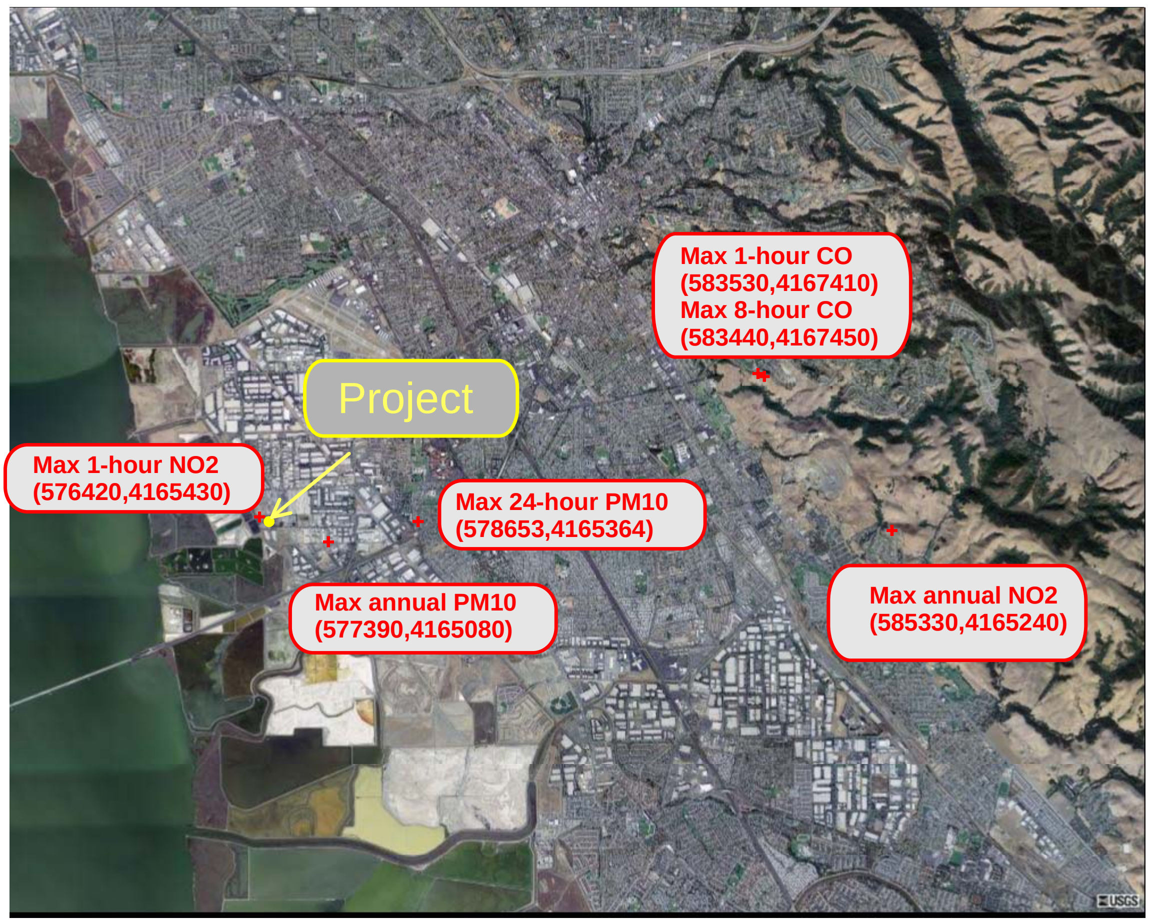


FIGURE 1. Location of project maximum impacts.

Table VI below contains the comparison of the ambient standards with the proposed project impacts added to the maximum background concentrations. The California ambient NO_2 standard is not exceeded from the proposed project.

TABLE 6 **California and national ambient air quality standard and ambient air quality level from the proposed project (μg/m^3)**						
Pollutant	Averaging Time	Maximum Background	Maximum Impact from Proposed Project	Maximum combined impact plus maximum background	California Standard	National Standard
NO_2	1-hour	143	227	370	470	---

CLASS I PSD INCREMENT ANALYSIS

EPA requires an increment analysis of any PSD source within 100 km of a Class I area which increases NO_2 or PM_{10} concentrations by 1 μg/m^3 or more (24-hour average) inside the Class I area. Point Reyes National Seashore is located roughly 62 km northwest of the project, and is the only Class I area within 100 km of the facility. Shown in Table VII are the results from an impact analysis using ISCST3. The table shows that the maximum 24-hour NO_2 and PM_{10} impacts within the Point Reyes National Seashore are well below the 1 μg/m^3 significance level (see Table VII)

TABLE 7 **Class I 24-hour air quality impacts analysis for the Point Reyes National Seashore (μg/m^3)**			
Pollutant	ISCST3	Significance level	Significant
NO_2	0.26	1.0	no
PM_{10}	0.21	1.0	no

VISIBILITY, SOILS AND VEGETATION IMPACT ANALYSIS

Visibility impacts were assessed using both EPA's VISCREEN visibility screening model and the Calpuff model. Both analyses show that the proposed project will not cause any impairment of visibility at Point Reyes National Seashore, the closest Class I area.

The project maximum one-hour average NO_2, including background, is 370 μg/m^3. This concentration is below the California one-hour average NO_2 standard of 470 μg/m^3. Crop damage from NO_2 requires exposure to concentrations higher than 470 μg/m^3 for periods longer than one hour.

Maximum project NO_2, CO, SO_2 and PM_{10} concentrations would be less than all of the applicable national primary and secondary ambient air quality standards, which are designed to protect the public welfare form any known or anticipated effects, including plant damage. Therefore, the facility's impact on soils and vegetation would be insignificant.

CONCLUSIONS

The results of the air quality impact analysis indicate that the proposed project would not interfere with the attainment or maintenance of applicable AAQS for NO_2, CO and PM_{10}. The analysis was based on EPA approved models and calculation procedures and was performed in accordance with Section 414 of the District's NSR Rule.

Appendix F

BACT Cost-Effectiveness Data

Energy Corporation

Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines

Contract No. DE-FC02-97CHIO877

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October 15, 1999

TABLE A-5
1999 CONVENTIONAL SCR COST COMPARISON

		Source	5 MW Class	25 MW Class	150 MW Class
Turbine Model			Solar Centaur 50	GE LM2500	GE Frame 7FA
Turbine Output			4.2 MW	23 MW	161 MW
Direct Capital Costs (DC):		Source			
Purchased Equip. Cost (PE):		MHIA			
Basic Equipment (A):		MHIA	$240,000	$660,000	$2,100,000
Ammonia injection skid and storage	0.00 x A	MHIA	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight:	0.08 A x B	OAQPS	$19,015	$52,746	$169,530
PE Total:			$256,704	$712,066	$2,288,649
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$20,536	$56,965	$183,092
Handling and erection:	0.14 x PE	OAQPS	$35,939	$99,689	$320,411
Electrical:	0.04 x PE	OAQPS	$10,268	$28,483	$91,546
Piping:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Insulation:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Painting:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
DI Total:			$77,011	$213,620	$686,595
DC Total:			$333,716	$925,686	$2,975,244
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$25,670	$71,207	$100,000
Construction and field expenses:	0.05 x PE	OAQPS	$12,835	$35,603	$114,432
Contractor fees:	0.10 x PE	OAQPS	$25,670	$71,207	$228,865
Start-up:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Performance testing:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Contingencies:	0.03 x PE	OAQPS	$7,701	$21,362	$68,659
IC Total:			$79,578	$220,741	$580,616
Total Capital Investment (TCI = DC + IC):			$413,294	$1,146,427	$3,555,861
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift; 25 $/hr for operator pay	OAQPS	$13,125	$13,125	$13,125
Supervisor:	15% of operator	OAQPS	$1,969	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift; 25 $/hr for labor pay	OAQPS	$13,125	$13,125	$13,125
Material:	100% of labor cost	OAQPS	$13,125	$13,125	$13,125
Utility Costs:	0% thermal eff; 600 (F) operating temp				
Gas usage	0.0 (MMcf/yr); 1,000 (Btu/ft3) heat value				
Gas cost	3,000 ($/MMcf)	variable			
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$10,584	$57,960	$405,720
Catalyst replace:	assume 30 ft^3 catalyst per MW, $400/$ft^3$, 7 yr. life	MHIA	$10,352	$56,690	$396,833
Catalyst dispose:	$15/$ft^3$*30 ft^3/MW*MW*.2054 (7 yr amortized)	OAQPS	$388	$2,126	$14,881
Ammonia:	360 ($/ton) [tons NH_3 = tons NO_x * (17/46)]	variable	$3,510	$14,820	$108,257
NH_3 inject skid:	5 (kW) blower; 5 kw (NH_3/H_2O pump)	MHIA	$5,040	$7,560	$27,720
Total DAC:			$71,219	$180,500	$994,755
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$8,266	$22,929	$71,117
Insurance:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Property tax:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Capital recovery:	10% interest rate, 15 yrs - period; 0.13 x TCI	OAQPS	$52,976	$143,272	$415,329
Total IAC:			$94,314	$213,935	$582,370
Total Annual Cost (DAC + IAC):			$165,533	$394,435	$1,577,125
NO_x Emission Rate (tons/yr) at 42 ppm:			33.4	141.0	1030.0
NO_x Removed (tons/yr) at 9 ppm,	79% removal efficiency		26.4	111.4	813.7
Cost Effectiveness ($/ton):			$6,274	$3,541	$1,938
Electricity Cost Impact (¢/kwh):			0.469	0.204	0.117

*Assume modular SCR is inserted into existing HRSG spool piece

REVISED
BEST AVAILABLE CONTROL
TECHNOLOGY ANALYSIS

TOWANTIC ENERGY PROJECT

FEBRUARY 2000

R·W·BECK

1998). This value is derived by a formula specified by CTDEP. The Project's maximum emission rate will be 10 ppm, or 43 percent of the allowable MASC limit.

The use of an SCR for NO_x control in combination with an oxidation catalyst for control of CO may increase particulate emissions in the form of ammonium bi-sulfates. Due to the insignificant amount of sulfur in natural gas fuel this impact will be extremely small. During oil-fired operation (the Project will be limited to 720 hours per year of oil-fired operation) the estimated amount of ammonium bi-sulfate emissions will increase particulate emissions by approximately 60 pounds per hour. This increase has only a minor effect on the maximum predicted air quality impacts from the Project, which are well within National Ambient Air Quality Standards.

An environmental benefit of SCR, when combined with a CO Oxidation Catalyst (Section 1.3), is a decrease in emissions of VOCs. Although the Project is not required to include VOCs in the PSD review as discussed in Section 1.1, the use of an SCR and CO Oxidation Catalyst will ensure that VOC emissions are minimal. The reduction in VOC emissions from SCR/CO Oxidation Catalyst is comparable to that from $SCONO_x$™.

ENERGY ANALYSIS

Use of SCR for NO_x control has an energy penalty due to the energy required to force combustion gases through the SCR reactor. There are other energy requirements associated with chemical transport and operation of equipment, pumps and motors but these are relatively small. Operation of the SCR for the Towantic Project is estimated to reduce electrical output by 1.46 MW or 11,510 MWh of electricity per year[1]. Not only is the electrical output reduced but the fuel use is increased by 135,800 MCF of gas per year.

1.2.4.1.3 ECONOMIC ANALYSIS

Table 3 presents the capital and annualized cost for the SCR control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst), energy penalties and ammonia. All costs are for two GE Frame 7FA gas turbine units, each including one HRSG, which includes the SCR unit.

[1] Based on annual capacity factor of 90%.

issues, poses a serious concern as to whether the Project could secure final construction approval from the Council.

As with the SCR/CO Oxidation Catalyst, SCONO$_x$™ will reduce VOC emissions along with NO_x and CO. The Project is not required to include VOCs in the PSD review, as discussed in Section 1.1, however, SCONO$_x$™ does have the added benefit of decreasing VOC emissions. The reduction in VOC emissions from SCONO$_x$™ is comparable to that from SCR/CO Oxidation Catalyst.

1.2.4.2 .2 ENERGY ANALYSIS

Use of SCONO$_x$™ for NO_x control has an energy penalty due to the energy required to force combustion gases through the SCONO$_x$™ reactor (pressure drop). Pressure drop through the SCONO$_x$™ unit is estimated at 5.25 inches by the manufacturer. This is compared to approximately 3.5 inches of pressure drop for a combined SCR and CO catalyst installed in a HRSG. The pressure drop of 5.25 inches reduces the total plant output by approximately 2.19 MW or 17,266 MWh per year. Not only is the electrical output reduced but the fuel use is increased by 202,200 MCF of gas per year.

Production of the steam used in the regeneration process also imposes a penalty in that the steam is not available to generate electricity. Based on the manufacturer's estimate of low-pressure steam requirements of 15,000 pounds per hour at 600°F and 20 psig, the steam turbine capability of the Project will be reduced by approximately 2.5 MW or 19,710 MWh per year.

The additional energy requirements of the SCONO$_x$™ system (relative to other NO_x control technology) means that the incremental amount of energy will not be supplied by the Project to meet energy needs in the service area. Other power plants will make-up the difference (approximately 4.2 MW) and this will result in a proportional increase in air pollution emissions. These other power plants may emit at levels equal to or greater than the Project.

As with any mechanical system, there are energy requirements associated with the operation of equipment, pumps and motors but these are relatively small. Finally, the SCONO$_x$™ system consumes 200 pounds per hour of natural gas total for regeneration of the catalyst plus leakage. This results in an annual natural gas consumption of 41,800 MCF.

1.2.4.2.3 ECONOMIC ANALYSIS

Table 4 presents the capital and annualized cost for the SCONO$_x$™ control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst) and energy costs. These costs are based on general information provided during a meeting with representatives from ABB Environmental. ABB Environmental was not able to provide a specific cost quote for a SCONO$_x$™ system for a GE 7FA combustion turbine with a HRSG. The projected capital costs are based on a SCONO$_x$™ system designed for an ABB GT-24 unit adjusted for the GE 7FA. The SCONO$_x$™ system also reduces