South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

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07-AFC-2
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March 21, 2008

Ms. Felicia Miller, Project Manager
California Energy Commission
1516 9th Street
Sacramento, CA 95814-5512

SUBJECT: Reliant Energy, Etiwanda, Proposed San Gabriel Generating Station Project (SGGS); Facility ID No. 115315, Location: 8996 Etiwanda Ave, Rancho Cucamonga, CA 91739; (07-AFC-2)

Dear Ms. Miller:

The South Coast Air Quality Management District (AQMD) has received and reviewed permit applications for the proposed power plant described above. Reliant Energy is proposing to install and operate a 721 megawatt (MW) natural gas fired power plant located at the facility location shown above.

The purpose of this letter is to inform you that the AQMD has evaluated the subject permit applications and made a preliminary determination that the equipment will comply with all of the applicable requirements of our Rules and Regulations. As a result, AQMD is issuing a Preliminary Determination of Compliance (PDOC) and a proposed Title V Permit for the project.

Based on the emission potential, this project is subject to the public notice requirements of AQMD Rules 212 (Standards for Approving Permits) and 3006 (Title V), and has applied for a significant revision to their existing Title V Permit. Therefore, the PDOC and proposed revision to the Title V permit for this project are subject to a public notice and a 45-day EPA review and a 30-day public review and comment period under AQMD Rules 212 and 3006. Please find enclosed a public notice for the subject project issued in accordance with AQMD Rules 212 and 3006. The public notice provides for a 30-day public comment and a 45-day EPA review period prior to making a final decision on issuance of the permit, and is also being published in a newspaper of general circulation in the vicinity of the nearest affected area. Additionally, the notice is being forwarded to other interested parties.

Also please note that in addition to being required to offset all applicable emission increases pursuant to AQMD Rules 1303(b)(2) and 2005(b)(2) and meeting the emission standards and other requirements discussed in the attached analysis, prior to issuing a Final Title V Permit, Reliant Energy must also demonstrate to the satisfaction of the Executive Officer that it has met all of the other applicable requirements of Rule 1309.1. These additional requirements are intended to be satisfied prior to actual release of the Priority Reserve credits and issuance of the Final Title V Permit and include, but not limited to, the following summarized list of requirements:

Rule 1309.1(c)(2)
Reliant Energy agrees to a permit condition requiring Best Available Retrofit Control Technology (BARCT) for all existing sources in the District

Rule 1309.1(c)(2)
Reliant Energy pays a mitigation fee pursuant to subdivision (g).

Rule 1309.1(c)(3)
Reliant Energy conducts a due diligence effort as approved by the Executive Officer, to secure available ERCs for requested Priority Reserve pollutants. Such efforts shall include securing available ERCs including those available through state emission banks or creating ERCs through SIP approved credit generation programs as available.

Rule 1309.1(c)(4)
Reliant Energy enters into a long-term contract (at least one year) with the State of California to sell at least 50 percent of the portion of power which it has generated using the Priority Reserve Credits and the Executive Officer determines at the time of permitting, and based on consultations with State power agencies that the State of California is both entering into such long term contract and that a need for such contract exists at the time of permitting, if the facility is a net generator.

Rule 1309.1(d)(6)
Reliant Energy must use any ERCs held first, before access to the Priority Reserve is allowed.

Rule 1309.1(d)(14)
Reliant Energy must secure final certification and approval for this project from the CEC, and either enters into a long term contract with Southern California Edison Company or the San Diego Gas and Electric Company or the State of California to provide electricity in Southern California, or petition the AQMD Governing Board for a waiver of this requirement.

If you wish to provide comments or have any questions regarding this project, please contact Mr. Chris Perri at (909) 396-2696/ cperri@aqmd.gov or Mr. John Yee at (909) 396-2531/ jyee@aqmd.gov.

Sincerely,

Mohsen Nazemi, P.E.
Assistant Deputy Executive Officer
Engineering & Compliance

Enclosures
Public Notice
Engineering Analysis

cc: Barry Wallerstein
Mike Carroll, Latham & Watkins, LLP
Robert Lawhn, Reliant Energy

CERTIFIED MAIL/RETURN RECEIPT REQUESTED

NOTICE OF INTENT TO ISSUE PERMIT
PURSUANT TO AQMD RULES 212 AND 3006

This notice is to inform you that the South Coast Air Quality Management District (AQMD) has received and reviewed permit applications for the proposed Reliant Energy, Etiwanda San Gabriel Generating Station (SGGS) Power Plant Project and intends to issue a Title V Facility Permit.

The AQMD is the air pollution control agency for the four county-region including Orange County and parts of Los Angeles, Riverside and San Bernardino counties. Anyone wishing to install or modify equipment that could control or be a source of air pollution within this region must first obtain a permit from the AQMD. Under certain circumstances, before a permit is granted, a public notice, such as this, is prepared by the AQMD and distributed.

The AQMD has evaluated the permit applications listed below for the following facility and determined that the project meets or will meet all applicable AQMD rules and regulations based upon the evaluation described below:

FACILITY: Reliant Energy Etiwanda, Inc
8996 Etiwanda Ave
Rancho Cucamonga, CA 91739
Facility ID No: 115315

CONTACT: Mr. Robert Lawhn, Director, Environmental Compliance
8996 Etiwanda Ave
Rancho Cucamonga, CA 91739

AQMD APPLICATION NUMBERS

Application Number	Equipment Description
468530	Gas Turbine No. 1
468531	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine No. 1
468533	Gas Turbine No. 2
468534	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine No. 2
468535	Auxiliary Boiler
468536	Aqueous Ammonia Storage Tank
468529	Title V Significant Modification

PROJECT DESCRIPTION

The project consists of the installation of two (2) new Siemens-Westinghouse combined cycle SGT6-5000F gas turbines with associated air pollution control systems, an auxiliary boiler and a 15,000 gallon capacity aqueous ammonia storage tank. The plant will have the capability of generating 721 MWs of electricity. Since the above equipment has the potential to emit pollutants in excess of the emission levels specified in AQMD Rule 212(g), a public notice is required.

PROJECT EMISSIONS

After the initial commissioning period, the total maximum monthly emissions from the operation of the proposed equipment in conjunction with the use of air pollution control systems is not expected to exceed the following:

Pollutant	Maximum Monthly Emissions, (pounds per month)
Nitrogen Oxides	29,523
Carbon Monoxide	69,414
Volatile Organic Compounds	12,182
Particulate Matter (diameter less than 10 microns)	9,248
Sulfur Dioxide	2,272

As a result of the burning of natural gas in the gas turbines, emissions from the proposed project also contains some pollutants that are considered toxic under AQMD Rule 1401-New Source Review of Toxic Air Contaminants. Therefore, a health risk assessment was performed for this project. The health risk assessment uses health protective assumptions in estimating actual risk to an individual person. Even assuming this health protective condition, the evaluation shows that the maximum individual cancer risk increase from the project is less than one-in-one-million. Also, acute and chronic indices, which measure non-cancer health impacts, are less than one. These levels of estimated risk are below the threshold limits of AQMD Rule 1401 (d) established for new or modified sources and below AQMD Rule 1309.1(b)(5)(A) for power plants. The health risk assessment (HRA) results are shown in the table below:

HRA Results

	Cancer Risk	Acute Hazard	Chronic Hazard
Gas Turbine No. 1	$1.31*10^{-7}$	0.032	0.008
Gas Turbine No. 2	$1.14*10^{-7}$	0.038	0.010
Auxiliary Boiler	$9.3*10^{-8}$	0.003	0.0004

Also, based on the engineering evaluation for this project, the AQMD has determined that the project complies with all of the applicable requirements to be qualified to access Priority Reserve credits pursuant to AQMD Rule 1309.1. However, the project must comply with additional requirements prior to the AQMD's release of the Priority Reserve credits and issuance of the Final Title V Permit.

This facility is a Federal Title V and Title IV (Acid Rain) facility. Pursuant to AQMD Title V Permits Rule 3006 – Public Participation, any person may request a proposed permit hearing on an application for an Initial Title V or significant permit revision by filing with the Executive Officer a complete Hearing Request Form (Form 500G) for a proposed hearing within 15 days of the date of publication of this notice, as shown below. This form is available on the AQMD website at http://www.aqmd.gov/permit/Formspdf/TitleV/AQMDForm500-G.pdf), or alternatively, the form can be made available upon request by contacting Mr. Chris Perri at the e-mail and telephone number listed below. On or before the date the request is filed, the person requesting a proposed permit hearing must also send by first class a copy of the request to the facility address and contact person listed above.

THE FOLLOWING REQUIREMENTS MUST BE COMPLIED WITH PRIOR TO THE ISSUANCE OF FINAL PERMIT

In order for AQMD to be able to release any Priority Reserve credits and issue a Final Title V permit to this project, the applicant must comply with additional requirements of AQMD Rules and Regulations, including but not limited to the following:

Rule 1303(b)(2)

Reliant Energy must provide emission offsets for NOx, VOC, SOx, and PM_{10} emissions. Emission offsets for PM10, SOx, and VOC will be provided in the form of Emission Reduction Credits (ERCs). Some or all of the emission offsets for PM10 and SOx may also be obtained from the AQMD's Priority Reserve pursuant to AQMD Rule 1309.1.

Rule 2005(b)(2)
Emission offsets for NOx will be in the form of RECLAIM Trading Credits (RTCs).

Rule 1309.1(c)(2)
Reliant Energy must pay a mitigation fee pursuant to subdivision (g).

Rule 1309.1(c)(3)
Reliant Energy must conduct a due diligence effort [based on an ERC cost not to exceed the applicable mitigation fee for that pollutant at the location of the electrical generating facility (EGF) and as specified in subdivision (g) of Rule 1309.1] approved by the Executive Officer to secure available ERCs for requested Priority Reserve pollutants. Such efforts shall include securing available ERCs including those available through state emission banks or creating ERCs through SIP approved credit generation programs as available.

Rule 1309.1(c)(4)
Reliant Energy must enter into a long-term contract (at least one year) with the State of California to sell at least 50 percent of the portion of power which it has generated using the Priority Reserve Credits and the Executive Officer determines at the time of permitting, and based on consultations with State power agencies that the State of California is both entering into such long term contract and that a need for such contract exists at the time of permitting, if the facility is a net generator.

Rule 1309.1(d)(6)
Reliant Energy must use any ERCs held first, before access to the Priority Reserve is allowed.

Rule 1309.1(d)(14)
Reliant Energy must secure final certification and approval for this project from the CEC, and must enter into a long term contract with Southern California Edison Company or the San Diego Gas and Electric Company or the State of California to provide electricity in Southern California, or petition the AQMD Governing Board for a waiver of this requirement.

The proposed permit and other information are available for public review at the AQMD's headquarters in Diamond Bar, and at the Paul A. Biane Library - located at 12505 Cultural Center Drive, Rancho Cucamonga 91739. Additional information including the facility owner's compliance history submitted to the AQMD pursuant to Section 42336, or otherwise known to the AQMD, based on credible information, is available at the AQMD for public review by contacting Mr. Chris Perri (cperri@aqmd.gov), Engineering and Compliance, South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, CA 91765-4182, (909) 396-2696. A copy of the draft Permit to Construct can also be viewed at http://www.aqmd.gov/webappl/PublicNotices/Search.aspx. .

Anyone wishing to comment on the air quality elements of this permit must submit comments in writing to the AQMD at the above address, attention Mr. Michael D. Mills. **Comments must be received within 30 days of the distribution/publication date of this notice, as shown below.** If you are concerned primarily about zoning decisions and the process by which the facility has been sited in this location, contact your local city or county planning department or the California Energy Commission at (916) 654-3936. For your general information, anyone experiencing air quality problems such as dust or odor can telephone in a complaint to the AQMD 24 hours a day by calling 1-800-CUT-SMOG (1-800-288-7664).

PRELIMINARY DETERMINATION OF COMPLIANCE

APPLICANT:
San Gabriel Power Generation, LLC
8996 Etiwanda Avenue
Rancho Cucamonga, CA 91739
SCAQMD ID# 115315

EQUIPMENT LOCATION:
8996 Etiwanda Avenue
Rancho Cucamonga, CA 91739

EQUIPMENT DESCRIPTION:

Section H of the Facility Permit ID# 115315

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
GAS TURBINE, UNIT NO.1, COMBINED CYCLE, NATURAL GAS, SIEMENS MODEL SGT6-5000F, 2027 MMBTU AT 25 DEGREES F WITH DRY LO NOX COMBUSTOR GENERATOR, 206.4 MW GROSS AT 25 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NO. 2, 340.0 MW GROSS AT 59 DEGREES F	D74 (B75) (B76) (B77)	C79 C80 S82	NOX: MAJOR SOURCE	**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 1.9 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 81 LBS/MMCF NATURAL GAS (1) [RULE 2012]; NOX: 0.050 LBS/MWH NATURAL GAS (5) [RULE 1309.1] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; **PM10**: 0.035 LBS/MWH (5) [RULE 1309.1] **SOX**: 0.060 LBS/MMBTU (8)	A63.1, A991., A99.2, A99.3, A99.3, A195.7, A195.8, A195.9, A327.1, A433.1, D29.2, D29.3, D29.4, D29.5, D82.1, B61.1, E193.5, E193.6, E193.7, I296.1, K40.3, , K67.1

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				[40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]	
BURNER, DUCT, NATURAL GAS, 623 MMBTU, LOCATED IN THE HRSG OF TURBINE NO. 1	D78		NOX: MAJOR SOURCE	**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 1.9 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 81 LBS/MMCF NATURAL GAS (1) [RULE 2012]; NOX: 0.050 LBS/MWH NATURAL GAS (5) [RULE 1309.1]; NOX: 0.20 LBS/MMBTU[40 CFR60 SUBPART DA] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; PM: 0.015 LBS/MMBTU [40 CFR60 SUBPART DA] **PM10**: 0.035 LBS/MWH (5) [RULE 1309.1] **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SO2: 0.2 LBS/MMBTU [RULE 40 CFR60 SUBPART DA]	A63.1, A991., A99.2, A99.3, A99.3, A195.7, A195.8, A195.9, A327.1, A433.1, D29.2, D29.3, D29.4, D29.5, D82.1, B61.1, E193.5, E193.6, E193.7, I296.1, K40.3, , K67.1
CO OXIDATION CATALYST, ENGELHARD, SERVING GAS TURBINE NO. 1, 26'L X 3'W X 61'H WITH 400 CU. FEET OF TOTAL CATALYST VOLUME	C79	D74			
SELECTIVE CATALYTIC REDUCTION, CORMATECH, VANADIUM TYPE, SERVING UNIT NO.1, 34'L X 2'W X 67'H, WITH 4500 CU. FEET OF TOTAL CATALYST	C80	D74		**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	A195.9, D12.5, D12.6, D12.7, E179.1, E179.2, E193.7

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
VOLUME WITH AMMONIA INJECTION, INJECTION GRID	(B81)				
STACK SERVING UNIT NO. 1, 150.5' H. X 19' DIA.	S82	D74			
GAS TURBINE, UNIT NO.2, COMBINED CYCLE, NATURAL GAS, SIEMENS MODEL SGT6-5000F, 2027 MMBTU AT 25 DEGREES F WITH DRY LO NOX COMBUSTOR GENERATOR, 206.4 MW GROSS AT 25 DEGREES F GENERATOR, HEAT RECOVERY STEAM TURBINE, STEAM, COMMON WITH GAS TURBINE NO. 1, 340.0 MW GROSS AT 59 DEGREES F	D83 (B84) (B85) (B86)	C88 C89 S91	NOX: MAJOR SOURCE	**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 1.9 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 81 LBS/MMCF NATURAL GAS (1) [RULE 2012]; NOX: 0.050 LBS/MWH NATURAL GAS (5) [RULE 1309.1] **VOC**: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475] **PM10**: 0.035 LBS/MWH (5) [RULE 1309.1] **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]	A63.1, A991., A99.2, A99.3, A99.3, A195.7, A195.8, A195.9, A327.1, A433.1, D29.2, D29.3, D29.4, D29.5, D82.1, B61.1, E193.5, E193.6, E193.7, I296.1, K40.3, , K67.1
BURNER, DUCT, NATURAL GAS, 623 MMBTU, LOCATED IN THE HRSG OF TURBINE NO. 2	D87		NOX: MAJOR SOURCE	**CO**: 2.0 PPM NATURAL GAS (4) [RULE 1703-PSD]; CO: 2000 PPM (5) [RULE 407] **NOX**: 1.9 PPM NATURAL GAS (4) [RULE 1303(a)(1)-BACT, RULE 1703-PSD]; NOX: 15 PPM NATURAL GAS (8) [40 CFR60 SUBPART KKKK]; NOX: 81 LBS/MMCF NATURAL GAS (1) [RULE 2012]; NOX: 0.050 LBS/MWH NATURAL GAS (5) [RULE 1309.1]; NOX: 0.20 LBS/MMBTU[40 CFR60 SUBPART DA]	A63.1, A991., A99.2, A99.3, A99.3, A195.7, A195.8, A195.9, A327.1, A433.1, D29.2, D29.3, D29.4, D29.5,

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
				VOC: 2.0 PPM NATURAL GAS (4) [RULE 1303(A)(1)-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; PM: 0.015 LBS/MMBTU [40 CFR60 SUBPART DA] **PM10**: 0.035 LBS/MWH (5) [RULE 1309.1] **SOX**: 0.060 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK] SO2: (9) [40CFR 72 – ACID RAIN]; SO2: 0.2 LBS/MMBTU [RULE 40 CFR60 SUBPART DA]	D82.1, B61.1, E193.5, E193.6, E193.7, I296.1, K40.3, K67.1
CO OXIDATION CATALYST, ENGELHARD, SERVING GAS TURBINE NO. 2, 26'L X 3'W X 61'H WITH 400 CU. FEET OF TOTAL CATALYST VOLUME	C88	D83			
SELECTIVE CATALYTIC REDUCTION, CORMATECH, VANADIUM TYPE, SERVING UNIT NO.2, 34'L X 2'W X 67'H, WITH 4500 CU. FEET OF TOTAL CATALYST VOLUME WITH AMMONIA INJECTION, INJECTION GRID	C89 (B90)	D83		**NH3**: 5 PPM (4) [RULE 1303(a)(1)-BACT]	A195.9, D12.5, D12.6, D12.7, E179.1, E179.2, E193.7
STACK SERVING UNIT NO. 2, 150.5' H. X 19' DIA.	S91	D83			
PROCESS 5: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, NO.3, HORIZONTAL, 50' L X 9' DIA X 12' H, WITH VAPOR RETURN LINE, AQUEOUS AMMONIA 29.4%, 15000 GALS A/N: 468536	D92				E144.1, C157.1, E193.7
PROCESS 8: AUXILIARY BOILER					
BOILER, NATURAL GAS, ENGLISH, WITH LOW NOX	D93		NOX: MAJOR	**CO**: 2000 PPM (5) [RULE 407; CO: 25 PPM (4) [RULE	A63.2, A99.5,

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: POWER GENERATION-GAS TURBINES					
BURNER, 56 MMBTU/HR WITH A/N: 468535 BURNER, LOW NOX, JOHN ZINK TODD RMB, 56 MMBTU/HR A/N: 468535	 (B94)		SOURCE	1703-PSD] **NOX**: 9 PPM (4) [RULE 1303-BACT, RULE 1703-PSD]; NOX: 55 LBS/MMCF (1) [RULE 2012] **VOC**: 3 PPM (4)]RULE 1303-BACT] **PM**: 0.1 GR/SCF (5) [RULE 409]	A195.10, A195.11, A195.12, D29.6, D82.2, E193.7, I296.1

BACKGROUND:

San Gabriel Generating Station (SGGS) is a proposed 721 MW (nominal) combined cycle power plant to be located at the existing site of the Reliant Energy, Etiwanda plant in Rancho Cucamonga (EGS), approximately one mile east of Interstate 15 (I-15) and 1.5 miles north of I-10. The proposed site is primarily industrial and is bordered by Etiwanda Avenue to the east, an existing SCE switchyard and vacant SCE land to the south, SCE-owned land to the west on which an GE LM6000 was recently constructed in the summer of 2007, a parcel to the southwest owned by IEUA containing 2 water tanks, and Burlington Northern Santa Fe Railroad tracks to the north. The entire EGS site is approximately 60 acres, and the new plant will be constructed on about 16.2 of those acres. The nearest inhabitant to the proposed project site is a residence approximately 0.4 mile from the site, and there are approximately 6 residential parcels within ½ mile of the project site. The site location map is presented in Figure 1.1. The SGGS site plan is presented in Appendix G.

The current EGS facility consists of 2 utility boilers each rated at 320 MW output and 2900 mmbtu/hr input, equipped with SCRs, 2 emergency engines for fire control (one gasoline, one LPG), a small gasoline dispensing unit, and two 10,000 gallon ammonia storage tanks. The boilers' steam is condensed with the use of conventional cooling towers with a rated flowrate of 130,000 gpm. The cooling towers do not appear on the AQMD permit because they are exempt from permitting under Rule 219.

San Gabriel Power Generation, LLC a wholly owned subsidiary of Reliant Energy, Inc. will be the facility owner and operator. The plant will be designed to supply power to the wholesale energy market through a proposed new substation adjacent to the property (to the south). Output will therefore depend on market conditions and dispatch requirements. The plant's expected availability is over 90% on an annual basis. The plant is designed to have the ability to start quickly (with the use of an auxiliary boiler - cold starts should be 2 ½ hours or less), and can operate in simple cycle mode if necessary.

The following applications for the project were submitted on May 1, 2007:

Table 1.1 – Project Application Numbers

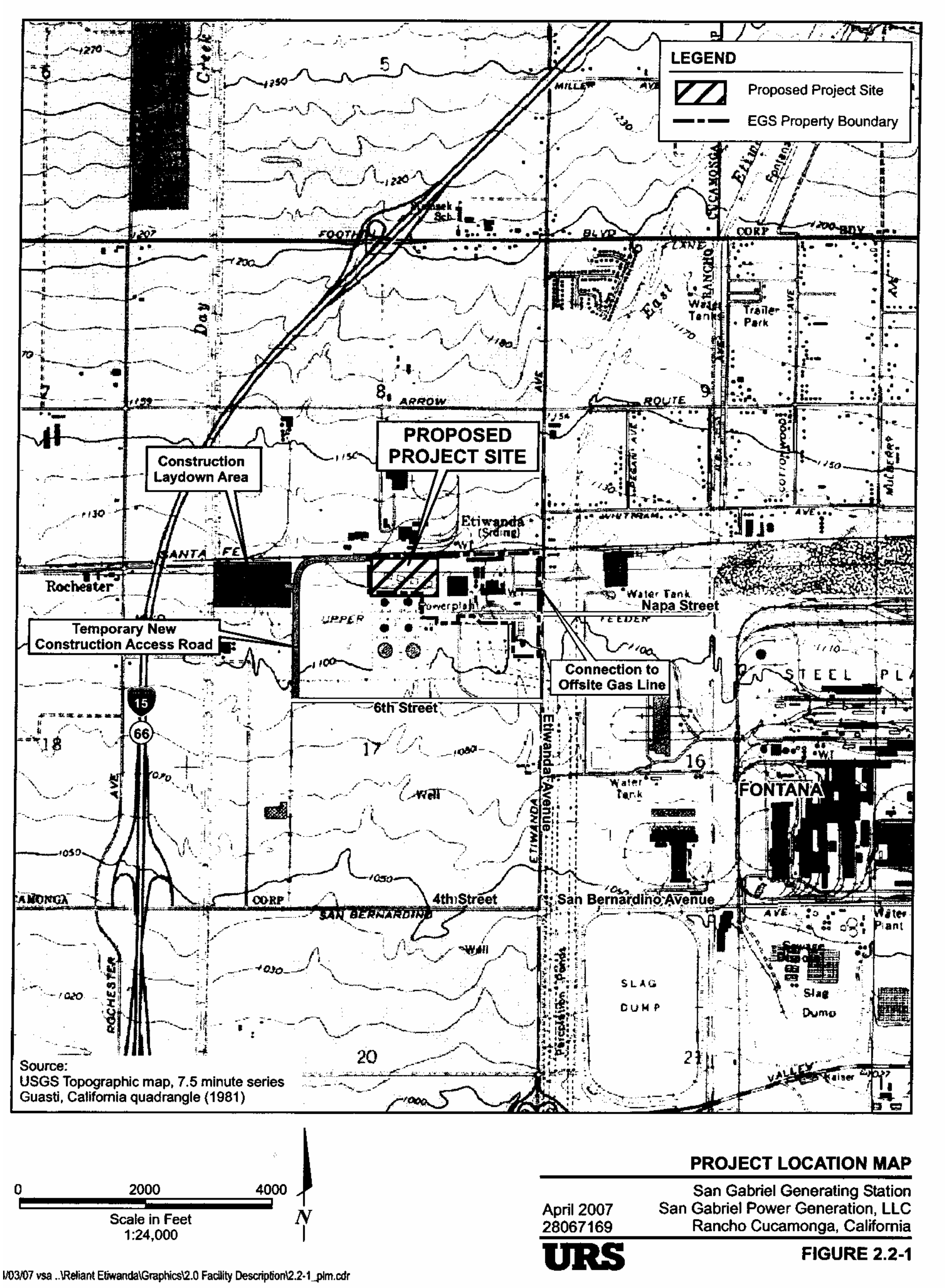
Application Number	Equipment Description
468530	Gas Turbine No. 1
468531	SCR/CO Catalyst No. 1
468533	Gas Turbine No. 2
468534	SCR/CO Catalyst No. 2
468535	Auxiliary Boiler
468536	Ammonia Storage Tank
468529	Title V Significant Revision

The applications were deemed complete on May 17, 2007. Refer to Appendix O for fees paid.

The plant will be evaluated as a significant revision to the existing Title V permit at the Reliant site (facility ID# 115315). The new project is also subject to the NOx RECLAIM and PSD regulations. The plant is considered a major revision to a major stationary source under Regulation XIII, and as such is subject to the full requirements of New Source Review. Other major environmental regulations that apply to the new project are 40 CFR72 – Acid Rain, 40CFR 60 Subpart KKKK – New Source Performance Standards for Gas Turbines, and AQMD Rule 1401 – Toxics. The project is also subject to the California Energy Commissioning licensing procedure and an Application for Certification (AFC) has been submitted with that agency (07-AFC-2).

Construction is scheduled to begin in September 2008, with the start of commercial operation targeted for July 2010.

Figure 1.1 –Site Location



Compliance History

The following information was obtained from the District's Compliance Tracking System for the 5-year period from 01/01/03 to 01/01/08 for Reliant Energy, Etiwanda facility.

Notice to Comply C98687
Issued 10/24/06 for failure to submit 500-SAM forms for the second half of each of the following compliance years 2003, 2004, 2005. The follow-up status was 'in compliance.'

Notice to Comply C98692
Issued 5/8/07 for failure to submit the QCER for first quarter 2004 in a timely manner, and for failure to update permit to accurately describe equipment currently at the site.

There were no complaints or Notices of Violation issued to the facility for the stated time period in the AQMD database. The facility has also submitted a statement certifying that all facilities owner and operated in the state are currently in compliance with all applicable air quality regulations, as required by Rule 1303.

<u>PROCESS DESCRIPTION:</u>

The gas turbine facility will consist of 2 combustion turbines equipped with dry low NOx combustors and evaporative inlet air cooling, 2 heat recovery steam generators (HRSG) each with duct burners, SCRs and oxidation catalysts, and a single steam turbine generator. Each combustion turbine will vent to a stack 150.5 feet tall. Aqueous ammonia for the SCRs will be stored in a 15,000 gallon tank. Also proposed is an auxiliary boiler rated at 56 mmbtu/hr for combustion turbine start up assist.

The system output will vary depending on the ambient air temperature condition, use of evaporative coolers, amount of auxiliary load, generator power factor, the amount of supplemental firing in the duct burners, and other factors. At ISO conditions, the net plant output will be 721 MW, at nominal (annual average) conditions, the net output will be 696 MW.

Table 2.1 Plant Output

	ISO 59 F- 60% RH	105 F-15% RH	25 F – 60% RH	63 F – 65% RH
Gas Turbine Heat Input, mmbtu/h LHV	3,630.0	3,277.2	3,685.9	3,446.8
Total Heat Input, mmbtu/h LHV (w/duct fire)	4,704.0	4,407.2	4,795.9	4,560.8
Gas Turbine Gross Output, kW	400,400	352,800	412,800	378,400
Steam Turbine Gross Output, kW	340,016	310,270	339,754	336,583
Total Gross Power Output, kW	740,416	663,070	752,554	714,983
Net Power Output, Kw	720,755	644,360	734,852	695,776
Net Plant Heat Rate, btu/kWh, LHV	6,526.5	6,839.6	6,526.3	6,555.0
Net Plant Heat Rate, btu/kWh, HHV	7,231.4	7,578.3	7,231.2	7,263.0

There will be no new transmission lines needed for the new project, except for the overhead transmission lines connecting to the SCE switchyard. There will however, be a new 20 inch diameter gas line to the existing Southern California Gas Company's gas transmission line, which is located about 200 feet east of the EGS property line.

Each of the components is discussed in more detail below:

Combustion Turbines
The two gas turbines will be Siemens-Westinghouse SGT6-5000F units rated at 171.5 MW (nominal), and arranged in a two-on-one configuration. The turbines will combust natural gas exclusively. Total heat input for 2 turbines at nominal conditions is 4,000 mmbtu/hr (HHV), fuel use at these conditions is approximately 3.96 mmcf/hr, based on a natural gas heat content of 1008 btu/cf. Pertinent turbines specs are summarized below:

Table 2.2 Turbine Data

Specification	
CT Manufacturer	Siemens- Westinghouse
Model	5000-F
Fuel Type	Natural gas
Maximum Fuel Consumption	2.03 mmcf/hr HHV (1 turbine @ 25 deg)
Maximum Exhaust Flow	840,653 dscfm @ 25 deg
Maximum Heat Input	2,046 mmbtu/hr HHV (1 turbine @ 25 deg)
Maximm Power Output	206.4 MW (1 turbine @ 25 deg)
Duct Burner Maximum Heat Input	627.1 mmbtu/hr HHV (@ 105 deg)
Duct Burner Maximum Fuel Consumption	0.62 mmcf/hr
NOx Combustion Control	DLN 9 ppm
Post Combustion Control	SCR 1.9 ppm 1 hour average
Ammonia Injection Rate per turbine	177 lbs/hr nominal, 183.4 lbs/hr maximum
Combined CT and DB Exhaust Flow	840,653 dscfm
Steam Turbine Output at 63°F Ambient	336.6 MW
Net Plant Heat Rate, LHV	6,603 btu/Kw @ ISO
Net Plant Heat Rate, HHV	7,263 btu/Kw @ ISO
Net Plant Efficiency, HHV	47.0%

Each turbine will exhaust to a Heat Recovery Steam Generator (HRSG). The HRSGs are designed to convert heat from the exhaust gas to produce steam for use in the steam turbine. The HRSGs will contain duct burners and the Air Pollution Control (APC) equipment. Each HRSG will vent to a separate exhaust stack.

Hot exhaust gases from the combustion turbine are used to produce steam for the steam turbine generator (STG), with additional heating provided by the duct burners. Low pressure (LP) steam exhausted from the STG is cooled and condensed through a dry cooling process in the air cooler condenser (ACC). The ACC is a multi-cell tubular heat exchanger with wet, saturated steam condensing on the tube side, while cooling air flows on the outside of the tubes. The ACC is rated at 1,900 mmbtu/hr. Condensate and make-up water is then pumped back to the HRSG with the use of 3 condensate pumps each rated at 3,500 gpm.

Air Pollution Control (APC) Equipment

APC equipment will be installed to control NOx, CO, and VOC from the gas turbines. Each APC system will consist of the following: 1) Dry Low NOx (DLN) Burners, 2) SCR, and 3) Oxidation catalyst.

<u>Dry Low NOx Combustor</u> - Each CT will include built-in pollution controls based on a dry combustion design (dry low-NOX combustor) to reduce NOx emissions. This control will reduce NOx emissions to 9 parts-per-million volume dry basis (ppmvd) at 15 percent oxygen (O_2). The dry low NOx control will be fully operational when the turbine reaches a load of approximately 50 to 60 percent.

Oxidation Catalyst System – An oxidation catalyst will be installed in the HRSG section of the turbine. The catalyst will be designed to reduce exhaust gas CO by about 80-85% to 2.0 ppm or less at 15% O2, and VOC by 30% to 2.0 ppm at 15% O2.

Table 2.3 Oxidation Catalyst Data

Specification	
Manufacturer	Engelhard
Catalyst Type	Stainless steel substrate with alumina platinum catalyst
Catalyst Volume	400 ft^3
Reactor Dimensions	26'L X 3'W X 61'H
Space Velocity	2731 m^{-1}
Area Velocity	19 ft/sec
CO Removal Efficiency	80-85%
Outlet CO	2.0 ppmvd at 15% O2
VOC Removal Efficiency	30%
Outlet VOC	2.0 ppmvd at 15% O2
Minimum operating temperature	300 °F

Selective Catalytic Reduction System – An SCR catalyst will be installed in the HRSG to reduce NOx emissions to 1.9 ppmvd at 15% O2 on a 1 hour average at loads above 50% (a 78-85% reduction from the DLN levels). The SCR catalyst will be located downstream of the CO catalyst, and will consist of a vanadium pentoxide type catalyst in a honeycomb structure. Aqueous ammonia (ammonium hydroxide at 19% concentration by weight) from the storage tank will be vaporized, diluted with air, and injection into the exhaust through an injection grid. The amount of ammonia injected will vary depending on NOx reduction requirements, but will be approximately a 1:1 molar ratio of ammonia to NOx. Expected average ammonia use is about 23.6 gallons per hour (177 lbs/hr/7.5 lbs/gal) per CTG/HRSG system. At an estimated average annual CTG capacity factor of 80%, estimated CCGS annual aqueous ammonia use would be 330,778 gallons (23.6 x 24 x 365 x 0.8 x 2).

Table 2.4 SCR Catalyst Data

Specification	
Manufacturer	Cormatech
Catalyst Type	Vanadium Pentoxide
Catalyst Volume	4500 ft^3
Reactor Dimensions	34'L X 2'W X 67'H
Space Velocity	243 m^{-1}
Area Velocity	15 ft/sec
Ammonia Injection Rate	172 lbm/hr
Ammonia Slip	5.0 ppm
Outlet NOx	1.9 ppm at 15%
Guarantee	78% efficiency for 3 years
SCR/CO catalyst Total Cost	$2.0 million
Minimum operating temperature	450 °F

Exhaust Stacks
Each turbine/HRSG will be equipped with identical 19-foot diameter 150.5 feet tall stacks. The stacks will contain sampling ports for exhaust gas testing.

Table 2.5 Stack Data

Specification	
Stack Diameter	19 feet
Stack Height	150' - 6"
Stack Area	283.4 ft^2
Exhaust gas temperature	200 deg F
Exhaust gas volume	48.4 mmscfh @ 105 deg F - 74.3 mmscfh @ 25 deg F
Exhaust gas velocity	10.2 feet/min @ 105 deg F – 15.7 feet/min @ 25 deg F

Duct Burners
Each HRSG will be fitted with a duct burner to increase steam production during peak operation. The duct burners are fired on natural gas and are each rated at 622.7 mmbtu/hr at 105 deg F.

Monitoring Systems
Each turbine will be equipped with continuous stack monitors for NOx, CO, and O2, along with a fuel meter. A data acquisition system is required to collect information from the analyzers and fuel meters to calculate exhaust flows and mass emissions of NOx for transmission through the remote terminal unit (RTU). Other parameters which are required to be measured and recorded include the ammonia injection rate, exhaust temperature prior to the SCR catalyst, CTG output, and pressure drop across the SCR catalyst. A NOx analyzer will be placed upstream of the SCR catalyst for fine tuning the ammonia injection rate and also for use in estimating ammonia slip.

Auxiliary Boiler
The auxiliary boiler is used to provide steam to the steam turbine seals and to create a vacuum on the air cooled condenser to assist the gas turbines during a cold start or warm start. This allows the gas turbines' Dry Low NOx combustors to begin operation quicker, which reduces NOx and CO emissions.

The boiler will be fired about 2 hours prior to a cold or warm start up, and the plant is also designed for the auxiliary boiler to operate overnight when an early-morning hot start is expected. This is done to maintain the air cooled condenser (ACC) vacuum and steam turbine sealing to shorten the startup by maintaining water quality and ACC vacuum.

The auxiliary boiler produces about 35,000 lb/hr of steam of which about 5,000 lb/hr is for sealing the steam turbine; the rest is used to provide a vacuum to the ACC. This steam is not provided directly to the steam turbine inlet but only to the steam turbine seals to prevent air from entering the ACC. The applicant has indicated that although some of the auxiliary boiler steam may enter the interior of the steam turbine while establishing the vacuum, this steam would not impart any rotational energy to the steam turbine. Therefore the aux boiler does not generate electricity.

The plant is designed with a full steam bypass; however, the cold and warm start times are limited by the maximum safe temperature ramp rate of the high-pressure drum's metal construction.

Total anticipated annual operation of the boiler is 4,000 hours. Pertinent boiler data is summarized in the following table:

Table 2.6 – Auxiliary Boiler Data

Specification	
Boiler Manufacturer	English, water tube type
Fuel Type	Natural gas
Rating	56 mmbtu/hr
Maximum Fuel Consumption	53,333 cf/hr
Maximum Exhaust Flow	15,246 acfm
Burner Model	TODD Rapid Mix Burner
# of Burners	1
Stack NOx Concentration	9 ppm
Stack CO Concentration	25 ppm

Ammonia Storage Tank
The 15,000 gallon ammonia tank will store a 29.4% aqueous ammonia solution for use in the turbines' SCRs. The tank is a horizontal pressure vessel with a PRVs set at 25 psig.

During loading, vapors from the tanks are vented back to the filling truck through the vapor return line. The tank is designed so that under normal operating conditions, the pressure will not exceed the prv setting.

Expected maximum ammonia use is about 17.8 gallons per hour (110 lbs/hr / 7.5 lbs/gal). At an expected average annual turbine capacity factor of 0.4, estimated annual aqueous ammonia use is 52,560 gallons (15 X 24 X 365 X 0.4), or about 3 tank turnovers per year

EMISSIONS:

Emissions from the gas turbine will consist of all 5 criteria pollutants plus toxics. Emissions are calculated for 4 basic operational modes as follows:

1. commissioning – a 1 time event which occurs following installation and just prior to bringing the turbine online for commercial operation
2. start up – occurs each time the turbine is started
3. normal operation
4. shutdown – occurs each time the turbine is shutdown

Table 3.1 - Operational Scenarios for SGGS

Scenario	Description
Commissioning	The commissioning operation will require each CT to operate individually as well as simultaneously under part load and full load. The testing will be performed on each CT for the purpose of “tuning in” the turbine combustor and control systems. Emissions are expected to be higher than normal operation. The commissioning will take about 500 operating hours per turbine over a period of about 5 months.
Startup	There are 3 types of starts – cold, warm , and hot. Cold starts occur after the turbine has been down for 72 or more hours, and the “start” will last about 2.5 hours (the time to reach proper operating temperature for full DLN, SCR and CO catalyst control). Warm starts occur after the turbine has been down 10 to 72 hours, and will last 2 hours. Hot starts occur when the turbine has been down less than 10 hours, and will last 40 minutes. Applicant anticipates 20 cold, 50 warm, and 164 hot starts per year.
Normal Operating	Normal operation is defined as when the turbine is operating at fully controlled levels (ie 1.9 ppm NOx, 2.0 ppm CO, and VOC).
Shutdown	During a turbine shutdown, the emission controls will continue to operate down to a level of 60% load. The final 20 minutes of the shutdown process will be partially to completely uncontrolled.

Emission calculations can be referenced in Appendix B.

Hourly Emissions

Table 3.2 Maximum Hourly Emissions Normal Operation (1 Turbine)

Pollutant	Uncontrolled Hourly Emissions	Controlled Hourly Emissions
NOx	392	18.6
CO	83	12.5
VOC	47	7.0
PM10	6.0	6.0
SOx	1.51	1.51
NH3	17.8	17.8

NOx uncontrolled back-calculated assuming 95% reduction, CO and VOC assuming 85% reduction

Table 3.3 Maximum Hourly Emissions Start Ups and Shutdowns (1 Turbine)

Pollutant	Cold Start		Warm start		Hot start		Shutdown	
	Lbs/hr max	Total lbs	Lbs/hr max	Total lbs	Lbs/hr max	Total lbs	Lbs/hr, max	Total, lbs
NOx	102	128	87	101	53	34	32	23
CO	1283	1405	1113	1132	628	368	433	431
VOC	69	82	63	66	42	26	15	14
PM10	6	12	6	10	6	2.3	6	1
SOx	1.1	2	1.1	1	1.1	0.2	1	0.3

Table 3.4 Maximum Hourly Emissions Start Ups and Shutdowns (2 Turbines)

Pollutant	Cold Start		Warm Start		Hot Start		Shutdown	
	Lbs/hr max	Total lbs	Lbs/hr max	Lbs/hr, max	Total, lbs	Total lbs	Lbs/hr max	Total, lbs
NOx	134	243	134	192	79	68	65	46
CO	1,740	2,806	1,846	2,261	738	735	866	862
VOC	99	163	97	131	52	51	30	28
SOx	2.1	2	2.1	2	2.1	0	2.1	0
PM10	12	19	12	15	12	5	12	3

Table 3.5 Highest Single Hour Emissions (1 Turbine)

Pollutant	Operating Scenario	Emissions, lbs/hr
NOx	Cold Start	102
CO	Cold Start	1283
VOC	Cold Start	69
PM10	Normal Operation	6
SOx	Normal Operation	1.51
NH3	Normal Operation	17.8

Table 3.6 Highest Single Hour Emissions (2 Turbines)

Pollutant	Operating Scenario	Emissions, lbs/hr
NOx	Cold Start	134
CO	Warm Start	1846
VOC	Cold Start	99
PM10	Normal Operation	12
SOx	Normal Operation	3.02
NH3	Normal Operation	35.6

Table 3.7 Highest Single Hour Emissions, (2 Turbines + Boiler)

Pollutant	Operating Scenario	Emissions, lbs/hr
NOx	Cold Start	135
CO	Warm Start	1847
VOC	Cold Start	99.1
PM10	Normal Operation	12.4
SOx	Normal Operation	3.05
NH3	Normal Operation	35.6

Daily Emissions

Table 3.8 Maximum Daily Emissions (1 Turbine)

Pollutant	Operating Scenario	Uncontrolled Daily Emissions	Controlled Daily Emissions
NOx	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	8316.4	538.4
CO	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	3564.9	2096.4
VOC	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	1158.3	241.8
PM10	24 hr normal	144.0	144.0
SOx	24 hr normal	36.2	36.2
NH3	24 hr normal	427.2	427.2

Table 3.9 Maximum Daily Emissions (2 Turbines)

Pollutant	Operating Scenario	Controlled Daily Emissions
NOx	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	1040.9
CO	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	3757.8
VOC	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	468.6
PM10	24 hr normal	288.0
SOx	24 hr normal	72.4
NH3	24 hr normal	854.4

Monthly Emissions

Table 3.10 30-Day Average Emissions (1 Turbine)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	1 cold start+0 warm starts+30 hot starts+36 shutdowns+681.2 hrs normal	14530.8	484.4
CO	1 cold starts+0 warm starts+30 hot starts+36 shutdowns+681.2 hrs normal	34320.6	1144.0
VOC	1 cold start+0 warm starts+30 hot starts+31 shutdowns+681.2 hrs normal	6,064.2	202.1
PM10	744 hrs normal	4464.0	148.8
SOx	744 hrs normal	1,123.4	37.4

Annual Emissions

Table 3.11 Commissioning Emissions

Pollutant	Emissions, 1 Turbine	Total Emissions, 2 Turbines	
	Lbs	Lbs	Tons
NOx	18,404	36,808	18.40
CO	597,465	1,194,930	597.47
VOC	9,618	19,236	9.62
PM10	414	828	0.41
SOx	2,832	5,664	2.83

Table 3.12 Annual Emissions Commissioning Year, 2 Turbines + Boiler

Pollutant	Normal Emissions, 2 Turbines[1]	Commissioning Emissions, 2 Turbines	Boiler Emissions[2]	Total Annual Emissions	
	Lbs	Lbs	Lbs	Lbs/yr	Tpy
NOx	160,506	36,808	1,446	198,760	99.4
CO	379,167	1,194,930	2,426	1,576,523	788.3
VOC	64,859	19,236	168	84,263	42.1
PM10	52,664	828	980	54,472	27.2
SOx	11,097	5,664	77	16,838	8.4
NH3	78,300	0	0	78,300	39.2

1- assumes 12 cold starts, 29 warm starts, 96 hot starts, 137 shutdowns, 4343.5 hours of normal operation (2333.3 hours with duct firing and 2010.2 w/o duct firing)
2- assumes 2,333 hrs/yr of operation

Table 3.13 Annual Emissions Non-Commissioning Year, 2 Turbines + Boiler

Pollutant	Normal Emissions, 2 Turbines[1]	Boiler Emissions[2]	Total Annual Emissions	
	Lbs	Lbs	Lbs/yr	Tpy
NOx	271,601	2,480	274,081	137.0
CO	583,436	4,160	587,596	293.8
VOC	109,024	288	109,312	54.7
PM10	90,049	1,680	91,729	45.9
SOx	19,089	132	19,221	9.6
NH3	135,000	0	135,000	67.5

1- assumes 20 cold starts, 50 warm starts, 164 hot starts, 137 shutdowns, 7446 hours of normal operation (4000 hours with duct firing and 3446 w/o duct firing)
2- assumes 4000 hrs/yr operation

Table 3.14 Emission Offsets

					Required Offsets			
Pollutant	Offset Basis	Turbine Emissions	Boiler Emissions	Offset Factor	Turbine 1	Turbine 2	Boiler	Total Plant
VOC	30-Day Average Emissions	228	2	1.2	274	274	2	550
PM10	30-Day Average Emissions	149	11	1.2	179	179	13	371
SOx	30-Day Average Emissions	37	1	1.2	44	44	1	89
CO	No offsets required							
Pollutant	Offset Basis	Turbine Emissions	Boiler Emissions	Offset Factor	Required RTCs			
NOx	Annual Emissions 1st 12 Months	197,314	1,446	1.0	198,760			
NOx	Annual Emissions After 1st 12 Months	271,601	2,480	1.0	274,081			

Toxic Emissions

Table 3.15 Toxic Emissions

Pollutant	Annual Emissions 1 Turbine, lbs/yr	Annual Emissions 2 Turbines, lbs/yr
Ammonia	1.35E+05	2.70E+05
1,3 Butadiene	7.91E+00	1.58E+01
Acetaldehyde	7.36E+02	1.47E+03
Acrolein	6.66E+01	1.33E+02
Benzene	6.00E+01	1.20E+02
Ethylbenzene	5.89E+02	1.18E+03
Formaldehyde	6.63E+03	1.33E+04
Propylene Oxide	5.34E+02	1.07E+03
Toluene	2.39E+03	4.78E+03
Xylene	1.18E+03	2.36E+03
Naphthalene	2.39E+01	4.78E+01
(a)anthracene	4.12E-01	8.24E-01
(a)pyrene	2.54E-01	5.08E-01
(b)fluoranthene	2.06E-01	4.12E-01
(k)fluoranthene	2.01E-01	4.02E-01
Chysene	4.60E-01	9.20E-01
(a,h)anthracene	4.29E-01	8.58E-01
(1,2,3-cd)pyrene	4.29E-01	8.58E-01
	Total, lbs/yr	2.94E+05
	Tons/yr	147.2

Auxiliary Boiler Emissions

Emissions from the boiler are calculated in Appendix P and Q, and are summarized below:

Table 3.16 Boiler Hourly, Daily, and Annual Emissions

Pollutant	Emissions		
	Lbs/hr	Lbs/day	Lbs/yr*
NOx	0.62	14.9	2,480
CO	1.04	25.0	4,160
VOC	0.072	1.7	288
PM10	0.42	10.1	1,680
SOx	0.033	0.80	132

**Based on 4,000 hours per year operation*

Table 3.17 Boiler 30 Day Average Emissions

Pollutant	Emissions	
	Lbs/month*	30 Day Average
NOx	461.3	15.4
CO	773.8	25.8
VOC	53.6	1.9
PM10	319.9	10.7
SOx	25.3	0.84

** Based on 744 hours per month operation*

Table 3.18 Boiler Emission Offsets

Pollutant	Emissions, lbs/day	Offset Factor	Required Offsets, lbs/day
VOC	2	1.2	2
PM10	11	1.2	13
SOx	1	1.2	1
CO	No offsets required		

Table 3.19 Boiler RTC Requirement

Pollutant	Emissions	
	Lbs/yr*	TPY
NOx	2480	1.24

**Based on 4,000 hours per year operation*

Table 3.20 Boiler Toxic Emissions

Pollutant	Emissions, lbs/hr	Emissions, lbs/yr*
Acetaldehyde	1.72E-04	6.88E-01
Acrolein	1.50E-04	6.00E-01
Benzene	3.22E-04	1.29E+00
Ethylbenzene	3.83E-04	1.53E+00
Formaldehyde	6.83E-04	2.73E+00
Hexane	2.55E-04	1.02E+00
Naphthalene	1.67E-05	6.66E-02
Toluene	1.47E-03	5.89E+00
Xylene	1.09E-03	4.38E+00
Propylene	2.94E-02	5.89E+00
(a)anthracene	9.99E-08	4.00E-04
(a)pyrene	6.66E-08	2.67E-04
(b)fluoranthene	9.99E-08	4.00E-04
(k)fluoranthene	9.99E-08	4.00E-04
Chysene	9.99E-08	4.00E-04
(a,h)anthracene	6.66E-08	2.67E-04
(1,2,3-cd)pyrene	9.99E-08	4.00E-04
7,12(a)anthracene	8.88E-07	3.55E-03
3-methlychloranthrene	9.99E-08	4.00E-04

** based on 4000 hours per year operation*

EVALUATION:

RULE 212-Standards for Approving Permits

This project is subject to Rule 212 public notice requirements because the daily maximum VOC, CO, NOx, and PM10 emissions from the project will all exceed the emissions thresholds specified in subdivision (g) of this rule. The facility is not located within 1000 feet of a school (the closest school is Sacred Heart Parish School located approximately 1.2 miles north of the site). The District will prepare the public notice and it will contain sufficient information to fully describe the project.

In accordance with subdivision (d) of this rule, the applicant will be required to distribute the public notice to each address within ¼ mile radius of the project.

Subdivision (g) requires that the public notification and comment process include all applicable provisions of 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10. The minimum requirements specified in the above documents are included in paragraphs (g)(1), (g)(2), and (g)(3).

In accordance with paragraph (g)(1) of this rule, the District will make the following information available for public inspection at the City of Rancho Cucamonga Public Library (Paul A. Biane Library) located at 12505 Cultural Center Drive, Rancho Cucamonga 91739, during the 30-day comment period: public notice, project information submitted by the applicant, and the District's permit to construct evaluation.

In accordance with paragraph (g)(2) of this rule, the public notice will be published in a newspaper which serves the area that will be impacted by the project.

In accordance with paragraph (g)(3) of this rule, the public notice will be mailed to the following persons: the applicant, the Region IX EPA administrator, the ARB, the chief executives of the city and county where the project will be located, the regional land use planning agency, and the state and federal land managers whose lands may be affected by the emissions from the proposed project.

After the public notice is published, there will be a 30-day period for submittal of public comments.

RULE 218 – Continuous Emission Monitoring

In order to insure the equipment meets the CO BACT limit as specified in the permit, a CO CEMS will be required by permit condition. The CO CEMS must be certified in accordance with Rule 218. The rule requires submittal of an “Application for CEMS” for approval. Once approved, CEMS data must be recorded and records of the data must be maintained on site for at least 2 years. Additionally, every 6 months a summary of the CEMS data must be submitted to AQMD. Any CEMS breakdowns must also be reported. Compliance with this rule is expected.

RULE 401 – Visible Emissions

This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. Visible emissions are not expected under normal operation from the turbines, boiler, or ammonia tank.

RULE 402 - Nuisance

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The subject equipment, including the turbines, boiler, and ammonia tank, are not expected to create nuisance problems.

RULE 403 – Fugitive Dust

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The applicant will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. Such measures include covering loose material on haul vehicles, watering, and using chemical stabilizers when necessary. The installation and operation of the turbines, boiler, and ammonia tank is expected to comply with this rule.

RULE 407 – Liquid and Gaseous Air Contaminants

This rule limits CO emissions to 2000 ppmv. The SO2 portion of the rule does not apply as the natural gas fired in both the boiler and the turbine will be subject to the sulfur limit in Rule 431.1. The CO emissions from the turbines will be controlled by an oxidation catalyst to 2 ppmvd at 15% O2. The CO emissions from the boiler are maintained with the use of the rapid mix burner at 25 ppm at 15% O2 Therefore, compliance with this rule is expected for both the turbines and the auxiliary boiler.

RULE 409 – Combustion Contaminants

This rule restricts the discharge of contaminants from the combustion of fuel to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes. Both the turbines and boiler are expected to meet this limit at the maximum firing load based on the calculations shown below. Compliance will be verified through the initial performance test.

Grain Loading = [(A x B)/(C x D)] x 7000 gr/lb

where:

A = PM10 emission rate during normal operation, 6.0 lb/hr
B = Rule specified percent of CO2 in the exhaust (12%)
C = Percent of CO2 in the exhaust (approx. 4.29% for natural gas)
D = Stack exhaust flow rate, 44.7E+06 scf/hr (@ 105°F)

Turbines

Grain Loading = $\dfrac{6.0 \text{ lbs/hr x } [(7000 \text{ grains/lb}) \text{ x } (12/4.29)]}{44.7 \text{ E+06 scf/hr}}$

= $\boxed{0.0026 \text{ grains/scf}}$

Auxiliary Boiler

Grain Loading = $\dfrac{0.42 \text{ lbs/hr x } [(7000 \text{ grains/lb}) \text{ x } (12/4.29)]}{565{,}800 \text{ scf/hr}}$

= $\boxed{0.015 \text{ grains/scf}}$

RULE 431.1 – Sulfur Content of Gaseous Fuels
The natural gas supplied to the turbines and the boiler is expected to comply with the 16 ppmv sulfur limit (calculated as H2S) specified in this rule. Commercial grade natural gas has an average sulfur content of about 4ppm. The SOx emissions from the turbines are based on 4 ppm or about 0.25 gr/100 cf concentration. A condition will be placed on the permit to require that the sulfur content is measured and recorded to insure compliance. The applicant will also comply with reporting and record keeping requirements as outlined in subdivision (e) of this rule.

RULE 475 – Electric Power Generating Equipment
This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from each turbine are estimated at 6.0 lbs/hr, and 0.0020 gr/scf during natural gas firing at maximum firing load (see calculations below). Therefore, compliance is expected. Compliance will be verified through the initial performance test as well as ongoing periodic testing.

$$Stack\ Exhaust\ Flow\left(\frac{scf}{hr}\right) = F_d\ x\ \frac{20.9}{(20.9 - \%O_2)}\ x\ TFD$$

where:
Fd: Dry F factor for fuel type, 8710 dscf/MMBtu
O2: Rule specific dry oxygen content in the effluent stream, 3%
TFD: Total fired duty measured at HHV, 2046.3 MMBtu/hr (@ 25°F)

$$Combustion\ Particulate\left(\frac{grain}{scf}\right)=\frac{PM_{10},lb/hr}{Stack\ Exhaust\ Flow,scf/hr}\ x\ 7000\ \frac{gr}{lb}$$

Stack flow = 8710(20.9/17.9)*2046.3 = 20.81 mmscf/hr

Combustion particulate = (6.0/20.81E+06)*7000 = $\boxed{0.0020 \text{ gr/scf}}$

RULE 1134 – Emissions of NOx from Gas Turbines
This rule applies to gas turbines, 0.3 MW and larger, installed on or before August 4, 1989. Therefore, as a new installation, the proposed SGGS turbines are not subject to this rule.

RULE 1135 – Emissions of NOx from Electric Power Generating Systems
This rule applies to the electric power generating systems of several of the major utility companies in the basin, including SCE and their successors. The plants which are included in the RECLAIM program are no longer subject to the requirements of this rule.

Rule 1146 – Emissions of NOx from Boilers and Steam Generators
The rule requires that any boiler with a heat input rating greater than 40 mmbtu/hr and an annual capacity factor greater than 25% limit the emissions of NOx to 30 ppm and CO to 400 ppm. The BACT limits for the boiler are 9 ppm NOx and 25 ppm CO which are lower than the rule limits, so compliance is expected. The rule allows units with a heat input capacity less than 90,000 therms to either maintain a 3% O2 level in the exhaust, or tune the unit twice per year, in lieu of the emission limits. The facility is not choosing either the 3% exhaust O2 or the tuning option.

REGULATION XIII/Rule 2005 – New Source Review
The new turbines are subject to NSR, including BACT, modeling, and offsets. Also, the addition of the turbines to the Reliant plant is considered a major modification to an existing major source. Therefore, the additional requirements for major sources are applicable. All requirements are discussed below.

- BACT

BACT is required for all criteria pollutants. For major sources, BACT is determined at the time the permit is issued, and is the Lowest Achievable Emission Rate (LAER), which has been Achieved in Practice. Based on recently issued permits, (including

Magnolia Power and Vernon City Power) AQMD has determined that BACT for combined cycle gas turbines is as follows:

Table 4.1 Turbine Required BACT

NOx	CO	VOC	PM_{10}	SOx	NH3
2.0 ppmdv @ 15% O2, 1 hour average	2.0 ppmdv @ 15% O2, 1 hour average	2.0 ppmdv @ 15% O2, 1 hour average	Natural gas fuel	Natural gas fuel with fuel sulfur content of no more than 1 grain/100 scf (about 16 ppm)	5.0 ppmdv @ 15% O2, 1 hour average

The applicant is proposing the following emission levels for this project. The emission levels of NOx, CO, VOC, and NH3 in the table are manufacturer guaranteed emissions under normal operating conditions.

TABLE 4.2 – Proposed Control Levels for the SGGS Turbines

NOX	CO	VOC	PM10	SOX	NH3
1.9 ppmvd @ 15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	2.0 ppmvd @ 15% O2, 1 hour average	Exclusive use of natural gas fuel, PM10 emissions of 6 lbs/hr	Exclusive use of natural gas fuel*	5.0 ppmdv @ 15% O2, 1 hour average

**Natural gas provided by the Gas Company is limited to 16 ppm in the South Coast by Rule 431.1. Generally, the actual sulfur content is about 4 ppm (4 ppm corresponds to 0.25 gr/100 scf)*

Table 4.3 Boiler Required BACT

NOx	CO
9 ppmdv @ 3% O2, 15 minute average	50 ppmdv @ 3% O2, 15 minute average

The applicant is proposing the following emission levels for the boiler. The emission levels of NOx, CO and VOC are manufacturer guaranteed emissions under normal operating conditions.

TABLE 4.4 – Proposed Control Levels for the Boiler

NOX	CO	VOC
9 ppmvd @ 3% O2, 15 minute average	25 ppmvd @ 3% O2, 15 minute average	3 ppmvd @ 3% O2, 15 minute average

- Modeling

Rule 1303(b)(1) requires air dispersion modeling for NOx, CO and PM10 to determine the impact from emissions on the air quality standards. Modeling evaluations were performed using the American Meteorological Society/USEPA AERMOD (version 04300) model and representative meteorological data from the Fontana meteorological station. Modeling analysis was performed for turbine startups and auxiliary boiler operation, normal turbine operation, and turbine commissioning operations. A discussion of the modeling procedure and the inputs used in the modeling are shown in Appendix E.

The air basin where the plant will be located is in attainment for NO2, CO, and SO2, and is in non-attainment for PM10. Therefore, the compliance determination for NO2, CO, and SO2 is a comparison of the project impact plus the background concentration to show that it does not exceed the AAQS. For PM10, the project impact should not exceed the Significant Increment. The results of the model show that the project will not cause a violation, or make significantly worse an existing violation, of any state or national ambient air quality standard. Model results are summarized in the tables below.

Table 4.5 Model Results – 2 Turbines + Boiler Start up/Shutdown and Normal Operation

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3) (1)	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2	1-hour(4)	98.16	229.09	327.52	NA	470(2)
	Annual	0.90	67.59	68.5	100	100(2)
CO	1-hour(4)	1335	5830	7165	40,000	23,000
	8-hour	88.56	5145	5233.6	10,000	10,000
SO2	1-hour	1.23	62.75	64.0	NA	655
	3-hour	1.43	41.83	43.3	1300	NA
	24-hour	0.40	39.22	39.6	365	105
	Annual	0.06	10.46	10.5	80	NA
PM10	24-hour	1.90	164	N/A	NA	2.5(3)
	Annual	0.46	63.3	N/A	NA	0.50(3)

(1) Background concentrations are the maximum recorded values from the Upland,, Fontana, San Bernardino 4th Street, and Riverside Rubidoux station for 1994, 1995, 1197, 1998, and 1999

(2) In February 2007, CARB approved new CAAQS for NO2, the new standards are 338 ug/m3 (1 hour) and 56 ug/m3 (annual). The standards are expected to take effect on March 20, 2008.
(3) Since the basin is non-attainment for PM10, the comparison is project impact to allowable significant change
(4) Peak 1 hour NO2 and CO are obtained from start up scenario 2 – 2 turbines starting at 30% load.

Table 4.6 Model Results, Single and Combined Turbines Commissioning

Modeling Scenario	Pollutant	Averaging Period	Maximum Predicted Impact, ug/m3	Background Concentration, ug/m3	Total Concentration, ug/m3
Single turbine commissioning	NOx	1 hour	80.59	229.09	310
	CO	1 hour	3,190.95	5,830	9,021
		8 hour	1,264.32	5,145	6,409
Combined Steam Blows	NOx	1 hour	76.21	229.09	305
	CO	1 hour	4,797.69	5,830	10,628
		8 hour	1,783.68	5,145	6,929

Background concentrations are the maximum recorded values from the Upland,, Fontana, San Bernardino 4th Street, and Riverside Rubidoux station for 1994, 1995, 1197, 1998, and 1999.

The modeling was reviewed by AQMD modeling staff and deemed acceptable. Refer to the memo from Jill Wynot to Mike Mills dated February 1, 2008.

- Offsets

Offsets in the form of ERCs or RTCs are required for the emissions of NOx, VOC, PM10, and SOx from the new turbines and boiler. Since the basin has been classified as in attainment for CO, and CO is not a precursor to any other criteria pollutant, no CO offsets are required for this project. The project proponent has proposed using ERCs obtained from the open market to offset the increase in VOC. For PM10 and SOx, the project proponent has requested Priority Reserve Credits (discussed further under the Rule 1309.1 analysis). NOx increases will be offset with RTC, both currently owned by Reliant as well as future purchases. ERCs and Priority Reserve credits must be secured prior to AQMD issuing the Permit to Construct. RTCs must be in place before start up of the equipment. Refer to Table 3.12 in the 'Emissions' section for a summary of the required offsets. **Currently, the facility holds no ERCs for CO, PM10, SOx, or VOC**.

Other requirements of Rule 1303:

Sensitive Zone Requirements. For this project, ERCs may be obtained from either Zone 1 or Zone 2A.

Facility Compliance. This facility is currently in compliance with all applicable rules and regulations of the District.

Alternative Analysis. The project is subject to the California Energy Commission licensing procedure. Under this procedure, a full analysis of the proposal is conducted, including project alternatives.

Protection of Visibility. Net Increase in emissions from the proposed project exceed the 15 tons per year PM_{10} and 40 tons per year NOx thresholds, and the site is within the specified distance of the Cucamonga Wilderness, but not the other Class I areas, as follows:

Table 4.7 Distances to Class I Areas

Federal Class I Area	Threshold Distance (km)	Distance from the SGGS (km)
Cucamonga Wilderness	28	14
San Gabriel Wilderness	29	36
San Gorgonio Wilderness	32	52
San Jacinto Wilderness	28	74
Agua Tibia Wilderness	28	84
Joshua Tree NP	29	99

Modeling was performed to determine project impacts on visibility on all Class I areas. Two different visibility impacts were modeled, one for plume effects on near field areas (within 50 km), and one for regional haze effects on far field areas (greater than 50 km). The results are presented in Tables 4.5 and 4.6.

Table 4.8 Results for Far Field Visibility Analysis

	Level of Acceptable Change = 5%		
Predicted % Change in Light Extinction Coefficient			
Class I Area	2001	2002	2003
San Gorgonia Wilderness	7.82*	4.77	3.15
San Jacinto Wilderness	2.02	2.90	2.16
Agua Tibia Wilderness	1.88	1.87	2.43
Joshua Tree National Park	2.82	1.45	2.70

** 2 days in 2001 exceeded 5% extinction rate threshold, on March 1 and July 7 @ 6.1% and 7.82% respectively.*

Table 4.9 Results for Near-Field Visibility Analysis

Class I Area	Emissions Scenario	Modeled Parameter	Sky		Terrain		Significance Threshold
			10°	140°	10°	140°	
Cucamonga Wilderness	Normal Operations	Color Difference Index (Delta E)	0.500	0.282	1.559	0.062	2
		Contrast (C)	0.009	-0.005	0.006	0	0.05
	Start Up	Color Difference Index (Delta E)	1.222	0.915	1.502	0.125	2
		Contrast (C)	0.004	-0.009	0.006	0.001	0.05
San Gabriel Wilderness	Normal Operations	Color Difference Index (Delta E)	0.228	0.102	0.458	0.027	2
		Contrast (C)	0.004	-0.002	0.003	0	0.05
	Start Up	Color Difference Index (Delta E)	0.487	0.335	0.433	0.076	2
		Contrast (C)	0.002	-0.004	0.003	0.000	0.05

<u>Statewide Compliance.</u> The applicant has submitted a statement certifying that all Reliant's stationary sources are currently in compliance with applicable state and federal environmental regulations.

<u>Rule 1309.1 Priority Reserve</u>

SGGS has requested Priority Reserve credits for PM10 and SOx emissions. The facility qualifies as an Electrical Generating Facility (EGF) as defined in the rule because it generates more than 50 MW per year for distribution in the state. The facility is located in Zone 3 and the generating capacity will be greater than 500 MWs, therefore, the following requirements apply:

Table 4.10 Rule 1309.1 Requirements

		SGGS	Complies?
Toxic Requirements			
Cancer[1]	<0.5 in-a-million	0.352	YES
Hazard Index[1]	<0.1	0.018, 0.065	YES
Cancer Burden[1]	<0.05	0.0067	YES
Criteria Pollutant Requirements			
PM10 Emissions[2]	NG only & ≤ 0.035 lb/MW-hr	NG only & 0.0162	YES
NOx Emissions[2]	≤ 0.050 lb/MW-hr	0.0494	YES
Total Combined Gas Turbine PM10 Hourly Emissions	≤ 30 lb/hr	12	YES
Gas Turbine PM10 24 Hour Impact	≤ 2.5 ug/m3 for total combined gas turbines	1.90	YES
Gas Turbine PM10 Annual Impact	≤ 0.5 ug/m3 for total combined gas turbines	0.46	YES
Annual Hours of Operation Limit	≤ 3000 hours if simple cycle	N/A	N/A

1 these determinations are based on the combined emissions of the gas turbines and auxiliary boiler
2 these determinations are made based on gross plant output at ISO conditions

The toxic risk model was reviewed by AQMD modeling staff and deemed acceptable. Refer to the memo from Jill Wynot to Mike Mills dated February 1, 2008.

Additionally, SGGS is required to:

1) perform a due diligence effort to procure offsets from the open market
2) enter into a long term (at least 1 year) contract to provide power to the state
3) provide at least 50% of its power to the state
4) agree to a permit condition requiring BARCT for pollutants requested from the priority reserve for all sources within the District
5) provided a discussion as to why the use of renewable/alternative energy is not a viable option at this site
6) agree to a permit condition requiring that the new turbines are fully operational at the rated capacity within 3 years of the permit to construct date
7) pay a mitigation fee as set forth in the rule.

The facility has been in the process of conducting a due diligence search for emission offsets of PM10 and SOx on the open market, through various emission brokers. At this point, no credits have been purchased, and the process will continue.

The facility does not currently have a long term contract for their power. Before their priority reserve credits (PRC) and permit can be issued, they must either obtain a contract, or they may seek a waiver of this requirement from AQMD governing board.

BARCT Requirement:

Reliant Energy's only location in the AQMD is their Etiwanda plant. The sources they operate at this site include their 2 boilers, 2 emergency diesel engines, a few storage tanks, and a small fuel dispensing unit. BARCT for PM10 and SOx for each of these sources is discussed below:

Source	BARCT Discussion
Boiler 3 Boiler 4	These are large utility boilers used to generate steam for power. The units are fired on pipeline natural gas which is low in particulate and sulfur thus minimizing emissions of those pollutants. There are no further reductions in PM or sulfur emissions that can be made to these units, therefore BARCT requirements are met.
Emergency ICE D3	This emergency fire engine is rated at 79 hp and is fired on LPG. LPG is very low in particulate and sulfur, therefore the emissions of these pollutants are minimized with the use of this fuel, and BARCT requirements are met.
Emergency ICE D4	This engine is fired on gasoline and is used for emergency power. It is rated at 227 hp.
Fuel Dispensing Equipment	There are no emissions of particulate or sulfur from this equipment.
Jet Fuel Storage Tank	There are no emissions of particulate or sulfur from this equipment
Abrasive Blasting Unit	The abrasive blasting unit is exempt from permitting under Rule 219. It is a small unit used for blasting metal parts during maintenance operations. The unit is equipped with a dust filter to minimize particulates, thus BARCT requirements for PM10 are met. There are no sulfur emissions from this unit.
Cooling Towers	The cooling towers serve Boilers 3 and 4. Particulate emissions from the towers are released in the drift. The design of more modern cooling towers minimizes the drift release. However, these towers are older installations. The facility will be required by permit condition to comply with BARCT for the towers prior to obtaining PRCs.
Waste Water	There are no emissions of particulate or sulfur from this equipment

Sump	
Ammonia Storage Tanks	There are no emissions of particulate or sulfur from this equipment

Alternative/ Renewable Energy Requirement

Reliant provided a discussion of the viability of each of the renewable options as they pertain to the Etiwanda site. Renewable/alternative energy is defined as hydropower, wind and wave power, solar and geothermal energy, and fossil fuel-based energy [provided the emissions are no more than those from a fuel cell] in the rule. Their discussion is summarized as follows:

Hydropower
There is no moving surface water or potentially dammable water body at this site to support a hydroelectric installation; therefore hydroelectricity is not a viable option at this site.

Wind Power
Reliant reports that the average wind speed at the Ontario Airport near the EGS site is 6.3 miles per hour. According to Reliant, a minimum of about 7 mph is needed to support a wind farm. Furthermore, Reliant estimates that at least 5 to 10 acres of land per megawatt would be needed based on the fact that each turbine physically occupies an area of about 0.3 to 0.5 acres, and the spacing between turbines needs to be 3 to 10 rotor diameters in order to avoid inter-turbine wake effects that reduce the efficiency of electrical production. SGGS will occupy about 16.2 acres of land. The land available at the proposed SGGS site would allow for the construction of only about 1 to 2 MW of capacity, which is far less than 10% of the proposed plant capacity of about 700 MWs. Therefore, wind power is not a viable option at this site.

Wave Power
The proposed SGGS site is not located on or adjacent to the Pacific Ocean; therefore wave power is not a viable option at this site.

Solar Energy
Solar energy is the energy contained in sunlight which can be harnessed and converted into solar power. Common solar plants use either photovoltaic arrays or solar thermal systems (CTS) to generate electricity. Photovoltaic systems convert sunlight directly into energy while a CTS concentrates the sun's energy into a tight beam which is used to heat a working fluid which in turn transfers its heat to a power generation system to generate electricity.

According to Reliant, the least land intensive solar technology available at this time, STS uses about 5 acres per megawatt. The 16.2 acres of land available at the proposed SGGS site would allow for the construction of only about a 3 MW solar project, which is far less than 10% of the proposed plant capacity of about 700 MWs. Therefore, solar power is not a viable option at this site

Geothermal Energy

There are no geothermal steam or hot water reservoirs located at the proposed SGGS site. Reliant reports that a map prepared in 1980 by the California Division of Mines and Geology (now the California Geological Survey), shows the nearest thermal spring is in the hills 7 miles to the north of the site. The water temperature of this spring is categorized as “warm” (less than 50 degrees Celsius), which is below the temperature generally required for viable geothermal power production. Thus generation of geothermal power is precluded by site conditions

Fuel Cell

Reliant looked at the feasibility of generating at least 10% of the total proposed plant output with the use of a fuel cell. According to Reliant, a fuel cell with a capacity of approximately 70MWs (10% of San Gabriel's output) would have a capital cost of at least $4400 per kilowatt. This is more than 4 times the estimated San Gabriel cost of $980 per kilowatt. The annual operation and maintenance cost of a fuel cell installation is estimated at $280 per kilowatt, more than 10 times the estimated San Gabriel cost of $25 per kilowatt. The significantly higher capital cost and annual operating costs make a merchant fuel cell facility economically nonviable. Additionally, the fuel cell installation would have to burn natural gas to generate hydrogen, as there is no source of pure hydrogen nearby.

RULE 1401 – New Source Review of Toxic Air Contaminants

This rule requires an analysis of the new permit units’ impacts due to the release of air toxics. A Tier 4 Health Risk Assessment was performed using CARB’s Hotspots Analysis and Reporting Program (HARP) (CARB, 2003). A model assessing the entire project’s impacts was also prepared in accordance with the requirements of Rule 1309.1. Model inputs and results are presented in Appendix E. The results show compliance with the limits specified in the rule, and are summarized below:

Table 4.11 Model Results, Individual Unit HRA

Permit Unit	Risk Type	Maximum Risk	Year of Data
Turbine 1	Cancer Risk per Million	0.131	1997
Turbine 2		0.114	1997
Aux Boiler		0.093	1997
Turbine 1	Chronic	0.008	1997
Turbine 2		0.010	1997
Aux Boiler		0.0004	1997
Turbine 1	Acute	0.032	1995
Turbine 2		0.038	1995
Aux Boiler		0.003	1995

The modeling was reviewed by AQMD modeling staff and deemed acceptable. Refer to the memo from Jill Wynot to Mike Mills dated February 1, 2008.

REGULATION XVII – Prevention of Significant Deterioration
The South Coast Basin where the project is to be located is in attainment for NO2, SO2, and CO emissions. Therefore a PSD analysis for these pollutants must be conducted. EPA recently re-delegated partial PSD authority to AQMD for certain initial and modification projects, including the San Gabriel Generating Station project.

PSD applies to a significant increase in emissions from a major stationary source. For a combined cycle power plant, the major source threshold is 100 tons per year based on actual emissions or potential to emit. If the facility is deemed to be major, Rule 1702 further defines a significant emission increase as 40 tpy or more of NO2 or SO2 or 100 tons per year or more of CO. The SGGS combined cycle project will result in an increase of 144 tpy of NOx, 10 tpy in SO2, and 373 tpy of CO. (includes emissions from the turbines and auxiliary boiler). The addition of the gas turbines is therefore considered a major source significant increase for NO2 and CO only, and is subject to PSD review for these pollutants.

Requirements for a significant emission increase under Rule 1703 include the following:

- Use of BACT [1703(a)(3)(B)]
- Modeling to determine impacts of the project of National and State AAQS and increases over the baseline concentration [1703(a)(3)(C)]
- Analysis of ambient air quality in the impact area [1703(a)(3)(D)]
- Analysis of project impacts on visibility, soil, and vegetation [1703(a)(3)(E)]

Affected Federal Land Managers have the opportunity to review and comment on the proposed project. AQMD has provided the Park Service and Forest Service with copies of the analysis.

The PSD analysis requires the following steps:

1. Determine whether preconstruction monitoring is required
2. Assessment of significance under PSD
3. Determine Ambient Air Quality Impacts
4. Determine Impacts in Class I Areas

SSGS performed modeling which indicated that the maximum annual NO2 impact from the proposed project is about 0.90 ug/m3 and from CO about 89 ug/m3. Rule 1704 allows an exemption from pre-construction monitoring if the annual NOx impact is less than 14 ug/m3 and the 8-hour CO impact is less than 575 ug/m3. Therefore, preconstruction monitoring is not required, and monitoring data from nearby monitoring stations can be used to determine ambient conditions.

PSD requires a full impact analysis if the preliminary analysis indicates the impacts exceed any of the significance thresholds in the Class II area OR if the facility is within 100 (one hundred) km of any Class I area, and has an impact exceeding 1 ug/m3 on a 24 hour basis. A full impact analysis would entail modeling to determine the impact on NAAQS and PSD increment from the emissions of not only the proposed source, but other existing and future sources in a prescribed impact zone.

Although the SGGS impacts are not above the 1 ug/m3 threshold, at the request of the Federal Land Manger, the facility conducted cumulative modeling to assess the impacts of the SGGS plant as well as any other emission sources within a 10 km radius. Four other sources were identified - Express Jet, Southern California Edison (SCE) Peaker plant, Johnson-Bateman Concrete Batch Plant and the Fontana Paper Mill. Additionally, there are 2 utility boilers (Units 3 and 4) owned and operated by Reliant existing at this site. Therefore, the facility conducted modeling for emissions from 1) the SGGS plant alone, as well as 2) from the SGGS plant plus the SCE peaker and the existing boilers 3 and 4.

The air quality analysis was conducted using different models depending on the distance to the Class I area, as discussed in Appendix E. The results of the analysis are presented in the following tables:

Table 4.12 Results of Ambient Air Quality Analysis Project Alone

	NOx Annual	SO2 3-hr	SO2 24-hr	SO2 Annual	PM10 24-hr	PM10 Annual
Proposed Class I SIL (ug/m3)	0.10	1.00	0.20	0.10	0.30	0.20
Maximum Predicted Class I Area Impacts (ug/m3)						
Cucamonga Wilderness	0.0006	0.0075	0.0014	0.00004	0.0055	0.0002
San Gabriel Wilderness	0.0008	0.0086	0.0018	0.00006	0.0073	0.0003
San Gorgonio Wilderness	0.019	0.026	0.008	0.001	0.095	0.009
San Jacinto Wilderness	0.006	0.013	0.003	0.0002	0.031	0.003
Agua Tibia Wilderness	0.002	0.009	0.002	0.0001	0.031	0.001
Joshua Tree NP	0.003	0.009	0.002	0.0002	0.026	0.002

Table 4.13 Results of Ambient Air Quality Analysis Cumulative

	NOx Annual	SO2 Annual	PM10 Annual
Proposed Class I SIL (ug/m3)	0.10	1.00	0.20
Maximum Predicted Class I Area Impacts (ug/m3)			
Cucamonga Wilderness	0.0006	0.00004	0.0002
San Gabriel Wilderness	0.0008	0.00006	0.0003
San Gorgonio Wilderness	0.005	0.0004	0.006
San Jacinto Wilderness	0.002	0.002	0.003
Agua Tibia Wilderness	0.001	0.0001	0.002
Joshua Tree NP	0.001	0.0001	0.002

Results as reported by the Forest Service

Table 4.14 Results of Air Quality Related Values Analysis (AQRVs) Project Alone

	Nitrogen	Sulfur
Class I Significance Level (kg/ha/yr)	0.005	0.005
Maximum Predicted Class I Area Impacts (kg/ha/yr)		
Cucamonga Wilderness	0.0004	0.0001
San Gabriel Wilderness	0.0001	0.0001
San Gorgonio Wilderness	0.0011	0.0005
San Jacinto Wilderness	0.0006	0.0002
Agua Tibia Wilderness	0.0003	0.0001
Joshua Tree NP	0.0006	0.0002

Table 4.15 Results of Air Quality Related Values Analysis (AQRVs) Cumulative

	Nitrogen	Sulfur
Class I Significance Level (kg/ha/yr)	0.005	0.005
Maximum Predicted Class I Area Impacts (kg/ha/yr)		
Cucamonga Wilderness	0.0013	0.0003
San Gabriel Wilderness	0.0005	0.0001
San Gorgonio Wilderness	0.0018	0.0004
San Jacinto Wilderness	0.0011	0.0003
Agua Tibia Wilderness	0.0005	0.0001
Joshua Tree NP	0.0007	0.0002

Results as reported by the Forest Service

Visibility Analysis

A cumulative analysis of visibility impacts was not conducted because the model does not take into account multiple sources, and it was determined that there was very little likelihood that the plumes from the proposed plant, the existing boilers 3 and 4 and the SCE peaker would merge before reaching the closest wilderness. The results of the visibility modeling can be referenced in Tables 4.5 and 4.6 presented under the Regulation XIII analysis. It should be noted that Forest Service, in addition to the near field visibility analysis, requested a far-field type analysis for the San Gabriel Wilderness despite its <50 km distance. This is because they felt that visibility there may be more strongly influenced by haze than by plume due to local topography and meteorology. Using the far field analysis results in the maximum regional haze light extinction changing from 5.65% to 5.82% with 2 days greater than 5% during the three year modeling period. Forest Service's conclusion is that 'Given the nature of the modeling and the operating assumptions, these values are not considered to be an indicator of future adverse regional haze conditions being created by this facility'.

The letter from Regional Forester Randy Moore to AQMD, dated February 6, 2008, with all the results and conclusions of the analysis can be referenced in the file.

EPA is required under Section 7 to perform an assessment of the impacts of the project on any endangered species located at the site in consultation with the Fish and Wildlife Service. The Delhi sands fly has been determined to be present at the site, and therefore a formal consultation between the parties has begun. The Section 7 consultation is ongoing at this time, however AQMD has determined that the PDOC can be released prior to the consultation being finalized, since a permit is not being issued yet. The AQMD permit cannot be granted until the Section 7 consultation is complete, and EPA issues their Boilogical Opinion. Furthermore, if the consultation results in any significant modification of the plant itself, a re-noticing of the project may be required.

Rule 2012 – RECLAIM, Monitoring Recording and Recordkeeping Requirements
The turbines will be classified as major NOx sources under RECLAIM. As such, they are required to measure and record NOx concentrations and calculate mass NOx emissions with a Continuous Emissions Monitoring System (CEMS). The CEMS will include in-stack NOx and O2 analyzers, a fuel meter, and a data recording and handling system. NOx emissions are reported to AQMD on a daily basis. The CEMS system will be required to be installed within 90 days of start up. Compliance is expected.

The boiler will be classified as major NOx source under RECLAIM because it is over 40 mmbtu/hr and the annual heat input is greater than 90 billion btu. As a major source, the boiler will be required to use a Continuous Emissions Monitoring System (CEMS) to measure NOx concentration and calculate mass emissions. The CEMS will includes in-stack NOx and O2 analyzers, a fuel meter, and a data recording and handling system. NOx emissions are reported to AQMD on a daily basis. The CEMS system will be required to be installed within 90 days of start up. Compliance is expected.

REGULATION XXX – Title V
The Reliant Energy facility is currently subject to Title V, and the addition of the combined cycle plant will be considered a significant revision to the existing Title V permit. Reliant has submitted a Title V revision application A/N 468529. As a significant revision, the permit is subject to a 30 day public notice and a 45 day EPA review and comment period. The public notice requirements are discussed in more detail under the "Public Notice Requirements" section of this report.

State Regulations

California Environmental Quality Act (CEQA)
The project is subject to the licensing procedure under the California Energy Commission (CEC). This procedure analyzes all aspects of the proposed project, and is subject to a public review and comment period. It is therefore considered equivalent to an Environmental Impact Report, and satisfies the requirements of CEQA.

Federal Regulations

NSPS for Steam Generators – 40CFR 60 Subpart Da
The fired HRSGs are subject to this subpart because their heat input rating is 623 mmbtu/hr which is greater than the applicability standard of 250 mmbtu/hr in the rule. The emission standards that apply are as follows:

NOx	0.2 lbs/mmbtu
PM	0.015 lbs/mmbtu
SO2	0.2 lbs/mmbtu

The regulation requires the installation of a CEMS to measure NOx and O2. A CEMS for opacity is not required since the unit burns natural gas exclusively and does not use post-combustion controls for PM or SO2 {60.49Da(u)(2)}. A PM CEMS is optional under 60.49Da(t). In lieu of a PM CEMS, a CO CEMS may be installed. An initial performance test is required.

Anticipated emissions from the gas turbine/duct burners are as follows:

NOx	0.007 lbs/mmbtu
PM	0.0025 lbs/mmbtu
SO2	0.0006 lbs/mmbtu

The expected emissions are all lower than subpart Da requirements. Compliance is expected.

NSPS for Steam Generators – 40CFR 60 Subpart Db

The fired HRSG is not subject to this subpart because the combined cycle turbine meets the applicability requirements of subpart KKKK {60.4b(i)}.

NSPS for Small Steam Generators – 40CFR 60 Subpart Dc

Although the boiler's heat input rating falls within the definition of affected unit under this subpart (10 to 100 mmbtu/hr), the emission standards apply only to units fired on coal or oil. Since the boiler is fired on natural gas exclusively, it is not subject to this regulation.

NSPS for Stationary Gas Turbines - 40CFR Part 60 Subpart GG

This regulation has been superseded by 40CFR 60 Subpart KKKK.

NSPS for Stationary Gas Turbines - 40CFR Part 60 Subpart KKKK

The turbines are subject to Subpart KKKK because their heat input is greater than 10.7 gigajoules per hour (10 MMBtu per hour) at peak load, based on the higher heating value of the fuel fired. Actual unit rating is 2027E+06 btu/hr (HHV) X 1055 joules/btu = 2128.5 gigajoules/hr. The standards applicable for a natural gas turbine greater than 850 mmbtu/hr are as follows:

NOx:	15 ppm at 15% O2 (0.43 lbs/MWh)
SOx:	0.90 lbs/MWh discharge, or 0.060 lbs/mmbtu potential SO2 in the fuel

Monitoring

The regulation requires that the fuel consumption and water to fuel ratio be monitored and recorded on a continuous basis, or alternatively, that a NOx and O2 CEMS be installed. For the SOx requirement, either a fuel meter to measure input, or a watt-meter to measure output is required, depending on which limit is selected. Also, daily monitoring of the sulfur content of the fuel is required if the fuel limit is selected. However, if the operator can provide supplier data showing the sulfur content of the fuel is less than 20 grains/100cf (for natural gas), then daily fuel monitoring is not required.

Testing
An initial performance test is required for both NOx and SO2. For units with a NOx CEMS, a minimum of 9 RATA reference method runs is required at an operating load of +/- 25 percent of 100 percent load. For SO2, either a fuel sample methodology or a stack measurement can be used, depending on the chosen limit. Annual performance tests are also required for NOx and SO2.

Compliance with the requirements of this rule is expected.

NESHAPS for Stationary Gas Turbines - 40CFR Part 63 Subpart YYYY
This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility with emissions of 10 tpy or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit. Neither the boilers or the turbines emit any single HAP at a rate of 10 tpy or more, and the total combined potential HAP emissions from all sources (2 turbines, aux boiler, 2 utility boilers) at the site are about 13 tpy, therefore, Reliant is not classified as a major source of HAPs, and subject is not to this subpart. Calculations can be referenced in Appendix K.

40 CFR Part 64 – Compliance Assurance Monitoring
The CAM regulation applies to emission units at major stationary sources required to obtain a Title V permit, which use control equipment to achieve a specified emission limit and which have emissions that are at least 100% of the major source thresholds on a pre-control basis. The rule is intended to provide “reasonable assurance” that the control systems are operating properly to maintain compliance with the emission limits. Based on the emission calculations shown in Appendix L, the Reliant facility is a major source and the turbine emissions are greater than the major source thresholds for NOx, CO, and VOC (but not PM10) and the turbines will be subject to an emission limit for each of these pollutants.

NOx
- ➢ Emission Limit – NOx is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – NOx is controlled with the SCR
- ✓ Requirement - As a NOx Major Source under Reclaim, the turbines are required to have CEMS under Rule 2012. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

CO

- ➢ Emission Limit – CO is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – CO is controlled with the oxidation catalyst.
- ✓ Requirement – The turbines will be required to use a CO CEMS under Rule 1303-BACT. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

VOC

- ➢ Emission Limit – VOC is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – VOC is controlled with the oxidation catalyst.
- ✓ Requirement – The oxidation catalyst is effective at operating temperatures above 300°F. The facility is required to maintain a temperature gauge in the exhaust (condition D12.3), which will measure the exhaust temperature on a continuous basis and record the readings on an hourly basis. The exhaust temperature is required to be at least 450°F, (with exceptions for start ups and shutdowns). This will insure that the oxidation catalyst is operating properly.

40 CFR Part 72 - (Acid Rain Provisions)

The facility will be subject to the requirements of the federal acid rain program, because the turbine is a utility unit greater than 25 MW. The acid rain program is similar to RECLAIM in that facilities are required to cover SO2 emissions with "SO2 allowances" that are similar in concept to RTCs. Reliant Energy has been given initial allowance allocations based on the past operation of their boilers. Reliant can either use those allocations, or if insufficient, must purchase additional allocations to cover the operation of the new turbines. The applicant is also required to monitor SO2 emissions through use of fuel gas meters and gas constituent analyses, or, if fired with pipeline quality natural gas, as in the case of the Reliant facility, a default emission factor of 0.0006 lbs/mmbtu is allowed. SO2 mass emissions are to be recorded every hour. NOx and O2 must be monitored with CEMS in accordance with the specifications of Part 75. Under this program, NOx and SOx emissions will be reported directly to the U.S. EPA. Part 75 requires that the CEMS be installed and certified within 90 days of initial startup. Compliance is expected. Note that Section K of the permit will include the Acid Rain rule references applicable to this facility, specifically Part 72 and Part 73.

Public Notice Requirements

The project is subject to public notice under Rule 212, and Rule 3006. Following are the notice requirements for each rule:

Rule 212

The project is subject to the noticing requirements of paragraph (g). This paragraph requires that notification follow the procedures of 40 CFR51, Section 51.161(b), and 40

CFR124, section 124.10. Rule 212(g) also requires 1) the AQMD analysis and information submitted by the operator must be available for public inspection in an area affected, 2) notice by prominent advertisement in the affected area, and 3) mailing a copy of the notice to EPA, CARB, chief executives of the city and county where the source is located, any land use agencies, State and Federal Land Managers or Indian Governing Body whose lands may be affected by the project.

In addition to the above, Section 124.10 requires that the notice be sent to Federal and State agencies with jurisdiction over fish, shellfish, and wildlife resources and over coastal zone management plans, the Advisory Council on Historic Preservation, State and Historic Preservation Officers.

The applicant must also distribute the notification to all addresses within a ¼ mile radius of the facility and demonstrate to the satisfaction of the AQMD that the distribution was accomplished.

Rule 3006
In addition to the parties receiving the notice under Rules 212 and Rule 3006 requires the notice be sent to those who request in writing to be on a list and other means determined by the EO to insure adequate notice to the affected public. Rule 3006 also requires that the notice contain the following:

i) The identity and location of the affected facility;
(ii) The name and mailing address of the facility's contact person;
(iii) The identity and address of the South Coast Air Quality Management District as the permitting authority processing the permit;
(iv) The activity or activities involved in the permit action;
(v) The emissions change involved in any permit revision;
(vi) The name, address, and telephone number of a person who interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision;
(vii) A brief description of the public comment procedures provided; and,
(viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

Title V also allows for a 45 day review and comment period by the U.S. EPA.

A copy of the notice and the mailing list of those sent the notice is included in this file.

RECOMMENDATION:

Based on the forgoing analysis, it is recommended that a Permit to Construct be issued following completion of the 30 day public and 45 day EPA review and comment period and securing all necessary emission offsets. The following conditions shall apply:

CONDITIONS:

GAS TURBINE

A63.1
The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM10	4464 LBS IN ANY ONE MONTH
SOx	1123 LBS IN ANY ONE MONTH
VOC	6064 LBS IN ANY ONE MONTH

The operator shall calculate the monthly emission limit(s) by using fuel use data and the following emission factors: VOC: 2.7 lbs/mmcf, PM10: 2.5 lbs/mmcf, and SOx: 0.57 lbs/mmcf.
[Rule 1303 – Offsets]

A99.1
The 2.0 PPM NOx emission limits shall not apply during commissioning, start-up, and shutdown periods. Start ups and shutdowns are defined in Condition A433.1. Commissioning shall not exceed 516 hours per turbine, with no more than 192 hrs uncontrolled and all operation after the combined steam blow controlled with SCR and CO catalyst. The commissioning of the turbines shall not be conducted simultaneously except for the following tests: Combined Steam Blow 1 and Combined Steam Blow 2. Shutdowns shall not exceed 20 minutes total (2 turbines combined).
[Rule 1303(a) – BACT, Rule 1303(b)(1) – Modeling, Rule 1303(b)(2) – Offsets, Rule 1703-PSD]

A99.2
The 2.0 PPM CO emission limits shall not apply during commissioning, start-up, and shutdown periods. Start ups and shutdowns are defined in Condition A433.1. Commissioning shall not exceed 516 hours per turbine, with no more than 192 hrs uncontrolled and all operation after the combined steam blow controlled with SCR and CO catalyst. The commissioning of the turbines shall not be conducted simultaneously except for the following tests: Combined Steam Blow 1 and Combined Steam Blow 2.. Shutdowns shall not exceed 20 minutes total (2 turbines combined) .

[Rule 1703-PSD]

A99.4
The 81 LBS/MMCF NOx emission limits shall only apply during turbine operation prior to CEMS certification for reporting NOx emissions.
[Rule 2012]

A195.7
The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) – BACT, Rule 1303(b)(1) – Modeling, Rule 1303(b)(2) – Offsets, Rule 1703-PSD]

A195.8
The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1703-PSD]

A195.9
The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) – BACT, Rule 1303(b)(1) – Modeling, Rule 1303(b)(2) - Offsets]

A327.1
For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[Rule 475]

A433.1
The operator shall comply at all times with the 2.0 ppm 1 hour BACT limit for NOx, except as defined in condition A99.1, and for the following operating scenarios:

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Cold Start	134 lbs/hr	NOx emissions not to exceed 243 lbs total per cold start (2 turbines combined). Cold start not to exceed 150 minutes total (2 turbines combined), and 20 starts per year per turbine. Cold start is defined as a start which occurs after no steam has been sent to the steam turbine for a period of 72 hours or more.
Warm Start	134 lbs/hr	NOx emissions not to exceed 192 lbs total per warm start (2 turbines combined). Warm start not to exceed 120 minutes total (2 turbines combined), and 50 starts per year per turbine. A warm start is defined as a start which occurs after no steam has been sent to the steam turbine for a period of 10 to 72 hours.
Hot Start	79 lbs/hr	NOx emissions not to exceed 68 lbs total per hot start (2 turbines combined). Hot start not to exceed 40 minutes total (2 turbines combined), 30 starts per month and 164 starts per year per turbine. A hot start is defined as a start which occurs after no steam has been sent to the steam turbine for a period of less than 10 hours.
Shutdown	65 lbs/hr	NOx emissions not to exceed 46 lbs total per shutdown (2 turbines combined). Shutdown not to exceed 20 minutes total (2 turbines combined), and 234 shutdowns per year per turbine.

[Rule 2005, Rule 1703-PSD]

B61.1
The operator shall not use natural gas containing the following specified compounds:

Compound	Grains per 100 scf
H2S	Greater than 0.25

This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H2S.
[Rule 1303(b) – Offset]

D29.2
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SOX emissions	District Method 307-91	Not applicable	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR
PM10 emissions	District Method 5	District approved averaging time	Outlet of the SCR
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at loads of 100, 75, and 50 percent.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with theVOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703-PSD, 40 CFR60 Subpart Da]

D29.3
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

The test shall be conducted and the results submitted to the District within 45 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit

[Rule 1303(a)(1) – BACT]

D29.4
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	District Method 307-91	Not applicable	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR
PM10 emissions	District Method 5	District approved averaging time	Outlet of the SCR

The test shall be conducted at least once every three years.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at 100 percent load.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 475]

D29.5

The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District method 100.1	1 hour	Outlet of the SCR
PM10 emissions	District Method 5	District approved averaging time	Outlet of the SCR

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at full load to demonstrate compliance with the 0.050 lbs/MW-hr NOx and 0.035 lbs/MW-hr PM10 requirements set forth in Rule 1309.1. If the actual measurement is within the accuracy of the devices used electrical power measurement, the results will be acceptable.

The lb/MW-hr emission rate of each electrical generating unit shall be determined by dividing (a) the lb/hr emission rate measured at the location and in accordance with the test method specified above, by (b) the gross electrical output of each electrical generating unit.

The test shall be conducted in accordance with District approved test protocol. The protocol shall be submitted to the District engineer no later than 45 days before the proposed test date and shall be approved by the District before the test commences.

The test protocol shall include the proposed operating conditions of the electrical generating unit during the test, the correction factor and documentation of its validity, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

[Rule 1309.1]

D82.1

The operator shall install and maintain a CEMS to measure the following parameters:

NOx and CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine, in accordance with approved AQMD Rule 218 and/or Reclaim CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD.

The CEMS will convert the actual NOx and CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The CEMS shall be installed and operated to measure the NOx and CO concentration over a 15 minute averaging time period.

The CEMS shall convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9%-%O2 d)][(Qg*HHV)/10E6], where

K = $7.267*10^{-8}$ (lbs/scf)/ppm
Cco = Average of 4 consecutive 15 min. average CO concentrations, ppm
Fd = 8710 dscf/MMBTU natural gas
%O2, d = Hourly average % by volume O2 dry, corresponding to Cco
Qg = Fuel gas usage during the hour, scf/hr
HHV = Gross high heating value of the fuel gas, BTU/scf

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 2012, Rule 1703-PSD]

E71.1
The operator shall not begin operation of this equipment until all sources within the District meet BARCT requirements, or on a schedule approved by the Executive Officer and no later than 3 years following the permit to construct issue date. The operator shall submit all supporting information and conduct a BARCT analysis pertaining to the existing cooling towers at this site prior to the completion of the public notice period of the draft permit for gas turbines 1 and 2.
[Rule 1309.1]

E193.5
The operator shall construct, operate and maintain this equipment according to the following requirements:

> Gas turbines 1 and 2, their associated control equipment, and the auxiliary boiler shall be fully and legally operational within 3 years of the date of the Permit to Construct.

[Rule 1309.1]

E193.6
The operator shall install this equipment according to the following requirements:

> PM10 emission rates from this equipment shall not exceed 6 lbs/hr and 0.035 lbs/MW-hr.
>
> NOx emission rates from this equipment shall not exceed 0.050 lbs/MW-hr.
>
> Compliance with the PM10 and NOx emission rates shall be demonstrated once over the lifetime of the project in accordance with condition D29.5

[Rule 1303-Offsets, Rule 1309.1]

E193.7
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

> In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-2 project.

[CEQA]

I296.1
This equipment shall not be operated unless the operator demonstrate to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the

commencement of each compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.

> To comply with this condition, the operator shall hold, prior to the 1st compliance year, a minimum of 98,657 (turbine 1) + 98,657 (turbine 2) + 1,446 (boiler) = 198,760 lbs/yr NOx RTC. This condition shall apply during the 1st 12 months of operation commencing with the initial operation of the gas turbine.
>
> To comply with this condition, the operator shall hold, prior to the beginning of all compliance years subsequent to the 1st compliance year, a minimum of 135,801 (turbine 1) + 135,800 (turbine 2) + 2,480 (boiler) = 274,081 lbs/yr of NOX RTCs. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.

[Rule 2005]

K40.3
The operator shall provide to the District a source test report in accordance with the following specifications:

> Source test results shall be submitted to the District no later than 60 days after the source test required under conditions D29.2, D29.3, D29.4, D29.5, and D29.6 was conducted.
> Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.
> All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute. All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.
> Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]

K67.1
The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

> Commissioning hours and type of control and fuel use
> Date and time of each start-up and shutdown

In addition to the requirements of a certified CEMS, natural gas fuel use records shall be kept during and after the commissioning period and prior to CEMS certification

Minute by minute data (NOx and O2 concentration and fuel flow at a minimum) for each turbine start up

[Rule 1303(b)(2) - Offsets]

SCR/CO CATALYST

A195.9

The 5 ppmv NH3 emission limit is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH3 (ppmv) = [a–b*c/1E+06]*1E+06/b

where,
a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 15% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months. The NOx analyzer shall be installed and operated within 90 days of initial start-up.

The operator shall use the above described method or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.

[Rule 1303(a)(1) – BACT]

D12.5

The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.

The injected ammonia rate shall be maintained within 8 gal/min and 25 gal/min except during start ups and shutdowns

[Rule 1303(a)(1) – BACT]

D12.6
The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.
The exhaust temperature at the inlet of the SCR shall be maintained at 450 deg F except during start up and shutdowns
[Rule 1303(a)(1) – BACT]

D12.7
The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months.
The differential pressure shall be maintained at 4 “ WC plus or minus 2 “ WC.
[Rule 1303(a)(1) – BACT]

E179.1
For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D12.5
Condition Number D12.6
[Rule 1303(a)(1) – BACT]

E179.2
For the purpose of the following condition numbers, continuous monitoring shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number: D12.7
[Rule 1303(a)(1) – BACT]

E193.7
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-2 project.

[CEQA]

Auxiliary Boiler

A63.2
The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM10	309.6 LBS IN ANY ONE MONTH
SOx	24.5 LBS IN ANY ONE MONTH
VOC	51.8 LBS IN ANY ONE MONTH

The operator shall calculate the annual emission limit(s) by using fuel use data and the following emission factors: VOC: 1.28 lbs/mmcf, PM10: 7.6 lbs/mmcf, and SOx: 0.60 lbs/mmcf.

[Rule 1303 – Offsets]

A99.5
The 55 LBS/MMCF NOx emission limits shall only apply during boiler operation prior to CEMS certification for reporting NOx emissions.

A195.10
The 9.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) – BACT, Rule 1303(b)(1) – Modeling, Rule 1303(b)(2) – Offsets, Rule 1703-PSD]

A195.11
The 25.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1703-PSD]

A195.12
The 3.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) – BACT, Rule 1303(b)(1) – Modeling, Rule 1303(b)(2) - Offsets]

C1.2
The operator shall limit the fuel usage to no more than 224 mmcf/yr
[Rule 1303(b)(2) – Offsets]

D29.6
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), and the flue gas flow rate.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the boiler during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at a load of 100 percent.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset]

D82.2
The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine, in accordance with an approved AQMD CEMS plan application.

The operator shall not install the CEMS prior to receiving initial approval from AQMD.

The CEMS will convert the actual NOx concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The CEMS shall be installed and operated to measure the NOx concentration over a 15 minute averaging time period.

[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 2012, Rule 1703-PSD]

E193.5

The operator shall construct, operate and maintain this equipment according to the following requirements:

Gas turbines 1 and 2, their associated control equipment, and the auxiliary boiler shall be fully and legally operational within 3 years of the date of the Permit to Construct.

[Rule 1309.1]

E193.7

The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-2 project.

[CEQA]

I296.1

This equipment shall not be operated unless the operator demonstrate to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.

To comply with this condition, the operator shall hold, prior to the 1st compliance year, a minimum of 197,314 (turbines) + 1,446 (boiler) = 198,760 lbs/yr NOx RTC. This condition shall apply during the 1st 12 months of operation commencing with the initial operation of the gas turbine.

To comply with this condition, the operator shall hold, prior to the beginning of all compliance years subsequent to the 1st compliance year, a minimum of 271,601 (turbines) + 2,480 (boiler) = 274,081 lbs/yr of NOX RTCs. In

accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.
[Rule 2005]

Ammonia Storage Tank

E144.1
The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.
[Rule 1303(a)(1)-BACT]

C157.1
The operator shall install and maintain a pressure relief valve set at 25 psig.
[Rule 1303(a)(1)-BACT]

E193.7
The operator shall upon completion of the construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-2 project.
[CEQA]

San Gabriel Generating Station
List of Appendices

Appendix A

Turbine Operating Parameters

	Case 1	Case 2	Case 3	Case ISO
	105 Deg F, 15% RH, Evap Coolers On	63 Deg F, 65% RH, Evap Coolers On	25 Deg F, 60% RH, Evap Coolers Off	59 Deg F, 60% RH, Evap Coolers Off
CT Power Output, kW	176,400	189,200	206,400	200,200
CT Heat Consumption, mmbtu/hr HHV	1,818.7	1,921.6	2,046.3	2,014.2
CT Fuel Rate, mmscf/hr	1.80	1.90	2.03	2.00
CT Exhaust Gas Flow Rate, lb/hr	3,669,555	3,842,650	4,081,620	4,044,598
DB Heat Consumption, mmbtu/hr HHV	627.1	618.2	616.0	596.0
DB Fuel Rate, mmscf/hr	0.62	0.61	0.61	0.59
CT/DB Flow Rate, lbs/hr	3,697,281	3,870,190	4,108,869	4,070,965
CT/DB Flow Rate, acfm	1,106,789	1,126,939	1,183,032	1,128,650
CT/DB Flow Rate, dscfm	744,776	784,103	840,653	827,904
Net Plant Heat Rate, Btu/kWhr HHV	7,231.4	7,578.3	7,231.2	7,263.0
Net Plant Efficiency, HHV	47.2%	45.0%	47.2%	47.0%

Exhaust gas molecular weight is approximately 28 lbs/lb-mol, exhaust gas O2 is approximately 13% before DB and 11% after DB.

Appendix B

Turbine Criteria Pollutant Emission Calculations

Normal Operation

- Table B.1 Manufacturer Guaranteed Emissions

Pollutant	Guarantee
NOx	1.9 ppm @15%
CO	2.0 ppm @ 15%
VOC	2.0 ppm @ 15%
PM10	6 lbs/hr*
SOx	No guarantee
NH3	5 ppm @ 15%

NOx guarantee is for loads above 60%

*SGGS requested a 6.0 lbs/hr PM10 limit, which is lower that the manufacturer guarantee. The lower factor is supported by several source test results for similar units as summarized in Appendix F.

SOx emissions are based on 4 ppm sulfur in the natural gas (0.25 gr/100 scf).

Table B.2 Normal Operation Emissions

Ambient Conditions	105°F, 15% RH	63°F, 65% RH	25°F, 60% RH	59°F, 60% RH
Fuel Type	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Evaporative Cooling On/Off	On	On	Off	On
O2 Percent (dry exhaust)	11.05	11.22	11.45	11.5
Exhaust Temp, °F	205°F	188°F	184°F	184°F
CT Gross Output, MW	176.400	189.200	206.400	200.200
Gross Heat Rate (HHV)	10310.1	10108.9	9914.2	10060.9
Turbine Heat Input, mmbtu/hr (HHV)	1818.7	1912.6	2046.3	2014.2
Turbine Fuel Use, mmscf/hr	1.80	1.90	2.03	2.00
Duct Burner Heat Rate, mmbtu/hr	627.1	618.2	616	596
Duct Burner Fuel Consumption, mmscf/hr	0.62	0.61	0.61	0.59
Stack Exhaust Flow, dscfm	744,766	784,103	840,653	827,904
Stack Exhaust Flow, ft3/hr (wet, actual O2)	3,697,281	3,870,190	4,108,869	4,070,965
Gross Plant Output, MW	663.070	714.983	752.554	740.416
Net Plant Output, MW	720.755	644.360	734.852	695.776
	NOx			
Concentration, ppmv @ 15% O2	1.9	1.9	1.9	1.9
Hourly Emissions, lb/hr	17.1	17.7	18.6	18.3
Daily Emissions, lb/day	410.4	424.8	446.4	439.2
lbs/mmcf (incl DB)	7.1	7.1	7.0	7.1
lbs/mmbtu (incl DB)	0.0070	0.0070	0.0070	0.0070
lbs/gross MW-hr (1 CTG)	0.0969	0.0936	0.0901	0.0914
Lbs/gross MW-hr (plant)	0.0516	0.0495	0.0494	0.0494
lbs/net MW-hr (plant)	0.0531	0.0329	0.0324	0.0326
	CO			
Concentration, ppmv @ 15% O2	2.0	2.0	2.0	2.0
Hourly Emissions, lb/hr	11.0	12.5	11.9	11.5
Daily Emissions, lb/day	264	300	285.6	276
lbs/mmcf (incl DB)	4.5	5.0	4.5	4.4
lbs/mmbtu (incl DB)	0.0045	0.0049	0.0045	0.0044
	VOC			
Concentration, ppmv, @ 15% O2	2.0	2.0	2.0	2.0
Hourly Emissions, lb/hr	6.5	6.5	7.0	7.0
Daily Emissions, lb/day	156	156	168	168
lbs/mmcf (incl DB)	2.7	2.6	2.7	2.7
lbs/mmbtu (incl DB)	0.0027	0.0026	0.0026	0.0027

Table B.2 Normal Operation Emissions (continued)

Ambient Conditions	105℉, 15% RH	63℉, 65% RH	25℉, 60% RH	59℉, 60% RH
Fuel Type	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Evaporative Cooling On/Off	On	On	Off	On
O2 Percent (dry exhaust)	11.05	11.22	11.45	11.5
Exhaust Temp, ℉	205℉	188℉	184℉	184℉
CT Gross Output, MW	176.400	189.200	206.400	200.200
Gross Heat Rate (HHV)	10310.1	10108.9	9914.2	10060.9
Turbine Heat Input, mmbtu/hr (HHV)	1818.7	1912.6	2046.3	2014.2
Turbine Fuel Use, mmscf/hr	1.80	1.90	2.03	2.00
Duct Burner Heat Rate, mmbtu/hr	627.1	618.2	616	596
Duct Burner Fuel Consumption, mmscf/hr	0.62	0.61	0.61	0.59
Stack Exhaust Flow, dscfm	744,766	784,103	840,653	827,904
Stack Exhaust Flow, ft3/hr (wet, actual O2)	3,697,281	3,870,190	4,108,869	4,070,965
Gross Plant Output, MW	663.070	714.983	752.554	740.416
Net Plant Output, MW	720.755	644.360	734.852	695.776
	SOX			
Concentration, ppmv, @ 15% O2	0.11	0.11	0.11	0.11
Hourly Emissions, lb/hr	1.38	1.43	1.51	1.46
Daily Emissions, lb/day	33.12	34.32	36.24	35.04
lbs/mmcf (incl DB)	0.57	0.57	0.57	0.56
lbs/mmbtu (incl DB)	0.0006	0.0006	0.0006	0.0006
	PM10			
Hourly Emissions, lb/hr	6.0	6.0	6.0	6.0
Daily Emissions, lb/day	144	144	144	144
lbs/mmcf (incl DB)	2.5	2.4	2.3	2.3
lbs/mmbtu (incl DB)	0.0025	0.0024	0.0023	0.0023
lbs/gross MW-hr (1 CTG)	0.0340	0.0317	0.0291	0.0300
lbs/gross MW-hr (plant)	0.0181	0.0168	0.0159	0.0162
lbs/net MW-hr (plant)	0.0186	0.0172	0.0163	0.0166
	NH3			
Concentration, ppm	5.0	5.0	5.0	5.0
Hourly Emissions, lb/hr	16.5	17.0	17.8	17.5
Daily Emissions, lb/day	396	408	427.2	420
Consumption, lbs/hr	172.8	177.0	183.4	179.2

- *calculated using combined heat input turbine + DB * 8170 * 3.54*
- *emissions are assumed to be maximum permitted levels for each case*

Start Up Operation

There are 3 basic types of starts – cold, warm, and hot. A cold start up is defined as a start of the CT that occurs after no steam has been sent to the steam turbine for a period of 72 hours or more. The cold start operation will take about 90 minutes for each turbine, and ends when the NOx emissions reach the BACT level of 2 ppm. This occurs at a turbine load of about 104 MW (60% load), when the DLN combustors are fully operational and the exhaust temperature is sufficient to allow the injected ammonia to react in the SCR. The second CT is started approximately 1 hour after the 1st CT. The total time for both turbines to complete the start is about 180 minutes. The cold start operation is assisted by the auxiliary boiler. The boiler may begin operation up to 2 hours prior to the CT start, and supplies heat to maintain the HRSG temperature.

A warm start occurs after no steam has been sent to the steam turbine for a period of 10 to 72 hours. The warm start will take about 2 hours to complete.

A hot start occurs after no steam has been sent to the steam turbine for a period of less than 10 hours. Approximate time to complete a hot start is 40 minutes.

SGGS anticipates about 20 cold, 50 warm, and 164 hot starts per year.

Following is a minute-by minute accounting of the cold start up operation as provided by Siemens. The first table shows the instantaneous lbs/hr emission rate for each turbine. The second table takes the instantaneous rate divided by 60 to get actual emissions.

Table B.3 Cold Start Instantaneous Emission Rate

Time	LEAD CTG - INSTANTANEOUS							LAG CTG - INSTANTANEOUS						
	CT Load		NO_X lb/hr	CO lb/hr	VOC lb/hr	SO_2 lb/hr	PM_{10} lb/hr	CT Load		NO_X lb/hr	CO lb/hr	VOC lb/hr	SO_2 lb/hr	PM_{10} lb/hr
0:00	Purge	0%	0	0	0	0	0							
0:01	Purge	0%	0	0	0	0	0							
0:02	Purge	0%	0	0	0	0	0							
0:03	Purge	0%	0	0	0	0	0							
0:04	Purge	0%	0	0	0	0	0							
0:05	Purge	0%	0	0	0	0	0							
0:06	Purge	0%	0	0	0	0	0							
0:07	Light Off	0%	33	400	42	0.2	3							
0:08	ramp to FSNL	0%	33	400	42	0.2	3							
0:09	ramp to FSNL	0%	33	400	42	0.2	3							
0:10	ramp to FSNL	0%	33	400	42	0.2	3							
0:11	ramp to FSNL	0%	33	400	42	0.2	3							
0:12	ramp to FSNL	0%	33	400	42	0.2	3							

0:13	ramp to FSNL	0%	33	400	42	0.2	3
0:14	ramp to FSNL	0%	33	400	42	0.2	3
0:15	ramp to FSNL	0%	33	400	42	0.2	3
0:16	ramp to FSNL	0%	33	400	42	0.2	3
0:17	ramp to FSNL	0%	33	400	42	0.2	3
0:18	ramp to FSNL	0%	33	400	42	0.2	3
0:19	ramp to FSNL	0%	33	400	42	0.2	3
0:20	ramp to FSNL	0%	33	400	42	0.2	3
0:21	ramp to FSNL	0%	33	400	42	0.2	3
0:22	ramp to FSNL	0%	33	400	42	0.2	3
0:23	ramp to FSNL	0%	33	400	42	0.2	3
0:24	FSNL	0%	41	3,307	41	0.2	5
0:25	5 MW	3%	52	2,930	47	0.2	5
0:26	10 MW	6%	69	2,365	55	0.3	5
0:27	15 MW	9%	86	1,799	63	0.3	5
0:28	20 MW	12%	99	1,376	72	0.3	5
0:29	20 MW	12%	99	1,376	72	0.3	5
0:30	20 MW	12%	99	1,376	72	0.3	5
0:31	20 MW	12%	99	1,376	72	0.3	5
0:32	20 MW	12%	99	1,376	72	0.3	5
0:33	20 MW	12%	99	1,376	72	0.3	5
0:34	20 MW	12%	99	1,376	72	0.3	5
0:35	20 MW	12%	99	1,376	72	0.3	5
0:36	20 MW	12%	99	1,376	72	0.3	5
0:37	20 MW	12%	99	1,376	72	0.3	5
0:38	20 MW	12%	99	1,376	72	0.3	5
0:39	20 MW	12%	99	1,376	72	0.3	5
0:40	20 MW	12%	99	1,376	72	0.3	5
0:41	20 MW	12%	99	1,376	72	0.3	5
0:42	20 MW	12%	99	1,376	72	0.3	5
0:43	20 MW	12%	99	1,376	72	0.3	5
0:44	20 MW	12%	99	1,376	72	0.3	5
0:45	20 MW	12%	99	1,376	72	0.3	5
0:46	20 MW	12%	99	1,376	72	0.3	5
0:47	20 MW	12%	99	1,376	72	0.3	5
0:48	20 MW	12%	99	1,376	72	0.3	5
0:49	20 MW	12%	99	1,376	72	0.3	5
0:50	20 MW	12%	99	1,376	72	0.3	5
0:51	20 MW	12%	99	1,376	72	0.3	5
0:52	20 MW	12%	99	1,376	72	0.3	5
0:53	20 MW	12%	99	1,376	72	0.3	5
0:54	20 MW	12%	99	1,376	72	0.3	5
0:55	20 MW	12%	99	1,376	72	0.3	5
0:56	20 MW	12%	99	1,376	72	0.3	5
0:57	20 MW	12%	99	1,376	72	0.3	5
0:58	20 MW	12%	99	1,376	72	0.3	5

0:59	20	MW	12%	99	1,376	72	0.3	5								
1:00	20	MW	12%	99	1,376	72	0.3	5	Purge		0%	0	0	0	0	0
1:01	20	MW	12%	99	1,376	72	0.3	5	Purge		0%	0	0	0	0	0
1:02	20	MW	12%	99	1,376	72	0.3	5	Purge		0%	0	0	0	0	0
1:03	20	MW	12%	99	1,376	72	0.3	5	Purge		0%	0	0	0	0	0
1:04	20	MW	12%	99	1,376	72	0.3	5	Purge		0%	0	0	0	0	0
1:05	20	MW	12%	99	1,376	72	0.3	5	Purge		0%	0	0	0	0	0
1:06	20	MW	12%	99	1,376	72	0.3	5	Purge		0%	0	0	0	0	0
1:07	20	MW	12%	99	1,376	72	0.3	5	Light Off		0%	33	400	42	0.2	3
1:08	24	MW	14%	103	1,236	84	0.4	5	ramp to FSNL		0%	33	400	42	0.2	3
1:09	28	MW	16%	106	1,143	92	0.4	5	ramp to FSNL		0%	33	400	42	0.2	3
1:10	32	MW	19%	109	1,049	100	0.4	5	ramp to FSNL		0%	33	400	42	0.2	3
1:11	36	MW	21%	115	960	104	0.4	5	ramp to FSNL		0%	33	400	42	0.2	3
1:12	40	MW	24%	120	969	96	0.4	5	ramp to FSNL		0%	33	400	42	0.2	3
1:13	44	MW	26%	112	956	109	0.4	5	ramp to FSNL		0%	33	400	42	0.2	3
1:14	48	MW	28%	132	991	75	0.5	5	ramp to FSNL		0%	33	400	42	0.2	3
1:15	52	MW	31%	137	1,000	66	0.5	5	ramp to FSNL		0%	33	400	42	0.2	3
1:16	56	MW	33%	142	877	60	0.5	5	ramp to FSNL		0%	33	400	42	0.2	3
1:17	60	MW	35%	150	692	50	0.5	5	ramp to FSNL		0%	33	400	42	0.2	3
1:18	64	MW	38%	155	569	44	0.5	5	ramp to FSNL		0%	33	400	42	0.2	3
1:19	68	MW	40%	162	384	34	0.6	5	ramp to FSNL		0%	33	400	42	0.2	3
1:20	72	MW	42%	142	323	31	0.6	5	ramp to FSNL		0%	33	400	42	0.2	3
1:21	76	MW	45%	122	261	28	0.6	5	ramp to FSNL		0%	33	400	42	0.2	3
1:22	80	MW	47%	92	168	24	0.6	5	ramp to FSNL		0%	33	400	42	0.2	3
1:23	84	MW	49%	72	107	22	0.6	5	ramp to FSNL		0%	33	400	42	0.2	3
1:24	88	MW	52%	57	69	19	0.7	5	FSNL		0%	41	3,307	41	0.2	5
1:25	92	MW	54%	41	48	13	0.7	5	5	MW	3%	52	2,930	47	0.2	5
1:26	96	MW	56%	30	34	10	0.7	5	10	MW	6%	69	2,365	55	0.3	5
1:27	100	MW	59%	20	20	6	0.7	6	15	MW	9%	86	1,799	63	0.3	5
1:28	104	MW	61%	9	5	3	0.8	6	20	MW	12%	99	1,376	72	0.3	5
1:29	108	MW	64%	10	5	3	0.8	6	20	MW	12%	99	1,376	72	0.3	5
1:30	112	MW	66%	10	4	3	0.8	6	20	MW	12%	99	1,376	72	0.3	5
1:31	116	MW	68%	10	3	3	0.8	6	20	MW	12%	99	1,376	72	0.3	5
1:32	120	MW	71%	10	3	3	0.8	6	20	MW	12%	99	1,376	72	0.3	5
1:33	124	MW	73%	10	3	3	0.8	6	20	MW	12%	99	1,376	72	0.3	5
1:34	128	MW	75%	10	3	3	0.8	6	20	MW	12%	99	1,376	72	0.3	5
1:35	132	MW	78%	10	3	3	0.8	6	20	MW	12%	99	1,376	72	0.3	5
1:36	136	MW	80%	12	3	2	0.9	6	20	MW	12%	99	1,376	72	0.3	5
1:37	140	MW	82%	12	3	2	0.9	6	20	MW	12%	99	1,376	72	0.3	5
1:38	144	MW	85%	12	3	2	0.9	6	20	MW	12%	99	1,376	72	0.3	5
1:39	148	MW	87%	12	3	2	0.9	6	20	MW	12%	99	1,376	72	0.3	5
1:40	152	MW	89%	12	3	2	0.9	6	20	MW	12%	99	1,376	72	0.3	5
1:41	156	MW	92%	12	3	1	1.0	6	20	MW	12%	99	1,376	72	0.3	5
1:42	160	MW	94%	12	3	1	1.0	6	20	MW	12%	99	1,376	72	0.3	5
1:43	164	MW	96%	12	3	1	1.0	6	20	MW	12%	99	1,376	72	0.3	5
1:44	168	MW	99%	12	3	1	1.0	6	20	MW	12%	99	1,376	72	0.3	5

1:45	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:46	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:47	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:48	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:49	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:50	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:51	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:52	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:53	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:54	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:55	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:56	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:57	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:58	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
1:59	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:00	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:01	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:02	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:03	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:04	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:05	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:06	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:07	170	MW	100%	14	3	1	1.1	6	20	MW	12%	99	1,376	72	0.3	5
2:08	170	MW	100%	14	3	1	1.1	6	24	MW	14%	103	1,236	84	0.4	5
2:09	170	MW	100%	14	3	1	1.1	6	28	MW	16%	106	1,143	92	0.4	5
2:10	170	MW	100%	14	3	1	1.1	6	32	MW	19%	109	1,049	100	0.4	5
2:11	170	MW	100%	14	3	1	1.1	6	36	MW	21%	115	960	104	0.4	5
2:12	170	MW	100%	14	3	1	1.1	6	40	MW	24%	120	969	96	0.4	5
2:13	170	MW	100%	14	3	1	1.1	6	44	MW	26%	112	956	109	0.4	5
2:14	170	MW	100%	14	3	1	1.1	6	48	MW	28%	132	991	75	0.5	5
2:15	170	MW	100%	14	3	1	1.1	6	52	MW	31%	137	1,000	66	0.5	5
2:16	170	MW	100%	14	3	1	1.1	6	56	MW	33%	142	877	60	0.5	5
2:17	170	MW	100%	14	3	1	1.1	6	60	MW	35%	150	692	50	0.5	5
2:18	170	MW	100%	14	3	1	1.1	6	64	MW	38%	155	569	44	0.5	5
2:19	170	MW	100%	14	3	1	1.1	6	68	MW	40%	162	384	34	0.6	5
2:20	170	MW	100%	14	3	1	1.1	6	72	MW	42%	142	323	31	0.6	5
2:21	170	MW	100%	14	3	1	1.1	6	76	MW	45%	122	261	28	0.6	5
2:22	170	MW	100%	14	3	1	1.1	6	80	MW	47%	92	168	24	0.6	5
2:23	170	MW	100%	14	3	1	1.1	6	84	MW	49%	72	107	22	0.6	5
2:24	170	MW	100%	14	3	1	1.1	6	88	MW	52%	57	69	19	0.7	5
2:25	170	MW	100%	14	3	1	1.1	6	92	MW	54%	41	48	13	0.7	5
2:26	170	MW	100%	14	3	1	1.1	6	96	MW	56%	30	34	10	0.7	5
2:27	170	MW	100%	14	3	1	1.1	6	100	MW	59%	20	20	6	0.7	6
2:28	170	MW	100%	14	3	1	1.1	6	104	MW	61%	9	5	3	0.8	6

Table B.4 Cold Start Actual Emissions

Time	LEAD CTG - ACTUAL CT Load		NO_X lb/hr	CO lb/hr	VOC lb/hr	SO_2 lb/hr	PM_{10} lb/hr	LAG CTG – ACTUAL CT Load	NO_X lb/hr	CO lb/hr	VOC lb/hr	SO_2 lb/hr	PM_{10} lb/hr
0:00	Purge	0%	0	0	0	0	0						
0:01	Purge	0%	0	0	0	0	0						
0:02	Purge	0%	0	0	0	0	0						
0:03	Purge	0%	0	0	0	0	0						
0:04	Purge	0%	0	0	0	0	0						
0:05	Purge	0%	0	0	0	0	0						
0:06	Purge	0%	0	0	0	0	0						
0:07	Light Off	0%	0.56	6.67	0.69	0.00	0.06						
0:08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:09	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:10	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:11	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:12	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:13	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:14	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:15	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:16	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:17	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:18	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:19	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:20	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:21	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:22	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:23	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06						
0:24	FSNL	0%	0.68	55.11	0.69	0.00	0.08						
0:25	5 MW	3%	0.87	48.83	0.78	0.00	0.08						
0:26	10 MW	6%	1.15	39.41	0.91	0.00	0.08						
0:27	15 MW	9%	1.43	29.99	1.04	0.00	0.08						
0:28	20 MW	12%	1.65	22.93	1.20	0.01	0.08						
0:29	20 MW	12%	1.65	22.93	1.20	0.01	0.08						
0:30	20 MW	12%	1.65	22.93	1.20	0.01	0.08						
0:31	20 MW	12%	1.65	22.93	1.20	0.01	0.08						
0:32	20 MW	12%	1.65	22.93	1.20	0.01	0.08						

0:33	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:34	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:35	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:36	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:37	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:38	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:39	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:40	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:41	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:42	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:43	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:44	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:45	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:46	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:47	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:48	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:49	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:50	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:51	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:52	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:53	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:54	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:55	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:56	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:57	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:58	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
0:59	20	MW	12%	1.65	22.93	1.20	0.01	0.08							
1:00	20	MW	12%	1.65	22.93	1.20	0.01	0.08	Purge	0%	0	0	0	0	0
1:01	20	MW	12%	1.65	22.93	1.20	0.01	0.08	Purge	0%	0	0	0	0	0
1:02	20	MW	12%	1.65	22.93	1.20	0.01	0.08	Purge	0%	0	0	0	0	0
1:03	20	MW	12%	1.65	22.93	1.20	0.01	0.08	Purge	0%	0	0	0	0	0
1:04	20	MW	12%	1.65	22.93	1.20	0.01	0.08	Purge	0%	0	0	0	0	0
1:05	20	MW	12%	1.65	22.93	1.20	0.01	0.08	Purge	0%	0	0	0	0	0
1:06	20	MW	12%	1.65	22.93	1.20	0.01	0.08	Purge	0%	0	0	0	0	0
1:07	20	MW	12%	1.65	22.93	1.20	0.01	0.08	Light Off	0%	0.56	6.67	0.69	0.00	0.06
1:08	24	MW	14%	1.72	20.60	1.40	0.01	0.08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06
1:09	28	MW	16%	1.77	19.04	1.54	0.01	0.08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06
1:10	32	MW	19%	1.82	17.49	1.67	0.01	0.08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06
1:11	36	MW	21%	1.91	16.01	1.74	0.01	0.08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06
1:12	40	MW	24%	1.99	16.15	1.60	0.01	0.08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06
1:13	44	MW	26%	1.87	15.93	1.81	0.01	0.08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06
1:14	48	MW	28%	2.20	16.52	1.25	0.01	0.08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06
1:15	52	MW	31%	2.28	16.67	1.10	0.01	0.08	ramp to FSNL	0%	0.56	6.67	0.69	0.00	0.06

1:16	56	MW	33%	2.37	14.62	1.00	0.01	0.08	ramp to FSNL		0%	0.56	6.67	0.69	0.00	0.06
1:17	60	MW	35%	2.49	11.54	0.84	0.01	0.08	ramp to FSNL		0%	0.56	6.67	0.69	0.00	0.06
1:18	64	MW	38%	2.58	9.49	0.73	0.01	0.08	ramp to FSNL		0%	0.56	6.67	0.69	0.00	0.06
1:19	68	MW	40%	2.71	6.41	0.57	0.01	0.08	ramp to FSNL		0%	0.56	6.67	0.69	0.00	0.06
1:20	72	MW	42%	2.37	5.38	0.52	0.01	0.08	ramp to FSNL		0%	0.56	6.67	0.69	0.00	0.06
1:21	76	MW	45%	2.04	4.35	0.47	0.01	0.08	ramp to FSNL		0%	0.56	6.67	0.69	0.00	0.06
1:22	80	MW	47%	1.54	2.81	0.41	0.01	0.08	ramp to FSNL		0%	0.56	6.67	0.69	0.00	0.06
1:23	84	MW	49%	1.21	1.78	0.36	0.01	0.08	ramp to FSNL		0%	0.56	6.67	0.69	0.00	0.06
1:24	88	MW	52%	0.95	1.15	0.31	0.01	0.08	FSNL		0%	0.68	55.11	0.69	0.00	0.08
1:25	92	MW	54%	0.68	0.80	0.22	0.01	0.09	5	MW	3%	0.87	48.83	0.78	0.00	0.08
1:26	96	MW	56%	0.51	0.56	0.16	0.01	0.09	10	MW	6%	1.15	39.41	0.91	0.00	0.08
1:27	100	MW	59%	0.33	0.33	0.11	0.01	0.09	15	MW	9%	1.43	29.99	1.04	0.00	0.08
1:28	104	MW	61%	0.16	0.09	0.05	0.01	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:29	108	MW	64%	0.16	0.08	0.05	0.01	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:30	112	MW	66%	0.16	0.07	0.05	0.01	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:31	116	MW	68%	0.17	0.05	0.05	0.01	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:32	120	MW	71%	0.17	0.04	0.05	0.01	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:33	124	MW	73%	0.17	0.04	0.05	0.01	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:34	128	MW	75%	0.17	0.04	0.05	0.01	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:35	132	MW	78%	0.17	0.04	0.05	0.01	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:36	136	MW	80%	0.19	0.05	0.03	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:37	140	MW	82%	0.19	0.05	0.03	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:38	144	MW	85%	0.19	0.05	0.03	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:39	148	MW	87%	0.19	0.05	0.03	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:40	152	MW	89%	0.19	0.05	0.03	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:41	156	MW	92%	0.21	0.05	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:42	160	MW	94%	0.21	0.05	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:43	164	MW	96%	0.21	0.05	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:44	168	MW	99%	0.21	0.05	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:45	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:46	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:47	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:48	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:49	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:50	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:51	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:52	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:53	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:54	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:55	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:56	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:57	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
1:58	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08

1:59	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:00	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:01	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:02	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:03	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:04	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:05	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:06	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:07	170	MW	100%	0.23	0.06	0.02	0.02	0.10	20	MW	12%	1.65	22.93	1.20	0.01	0.08
2:08	170	MW	100%	0.23	0.06	0.02	0.02	0.10	24	MW	14%	1.72	20.60	1.40	0.01	0.08
2:09	170	MW	100%	0.23	0.06	0.02	0.02	0.10	28	MW	16%	1.77	19.04	1.54	0.01	0.08
2:10	170	MW	100%	0.23	0.06	0.02	0.02	0.10	32	MW	19%	1.82	17.49	1.67	0.01	0.08
2:11	170	MW	100%	0.23	0.06	0.02	0.02	0.10	36	MW	21%	1.91	16.01	1.74	0.01	0.08
2:12	170	MW	100%	0.23	0.06	0.02	0.02	0.10	40	MW	24%	1.99	16.15	1.60	0.01	0.08
2:13	170	MW	100%	0.23	0.06	0.02	0.02	0.10	44	MW	26%	1.87	15.93	1.81	0.01	0.08
2:14	170	MW	100%	0.23	0.06	0.02	0.02	0.10	48	MW	28%	2.20	16.52	1.25	0.01	0.08
2:15	170	MW	100%	0.23	0.06	0.02	0.02	0.10	52	MW	31%	2.28	16.67	1.10	0.01	0.08
2:16	170	MW	100%	0.23	0.06	0.02	0.02	0.10	56	MW	33%	2.37	14.62	1.00	0.01	0.08
2:17	170	MW	100%	0.23	0.06	0.02	0.02	0.10	60	MW	35%	2.49	11.54	0.84	0.01	0.08
2:18	170	MW	100%	0.23	0.06	0.02	0.02	0.10	64	MW	38%	2.58	9.49	0.73	0.01	0.08
2:19	170	MW	100%	0.23	0.06	0.02	0.02	0.10	68	MW	40%	2.71	6.41	0.57	0.01	0.08
2:20	170	MW	100%	0.23	0.06	0.02	0.02	0.10	72	MW	42%	2.37	5.38	0.52	0.01	0.08
2:21	170	MW	100%	0.23	0.06	0.02	0.02	0.10	76	MW	45%	2.04	4.35	0.47	0.01	0.08
2:22	170	MW	100%	0.23	0.06	0.02	0.02	0.10	80	MW	47%	1.54	2.81	0.41	0.01	0.08
2:23	170	MW	100%	0.23	0.06	0.02	0.02	0.10	84	MW	49%	1.21	1.78	0.36	0.01	0.08
2:24	170	MW	100%	0.23	0.06	0.02	0.02	0.10	88	MW	52%	0.95	1.15	0.31	0.01	0.08
2:25	170	MW	100%	0.23	0.06	0.02	0.02	0.10	92	MW	54%	0.68	0.80	0.22	0.01	0.09
2:26	170	MW	100%	0.23	0.06	0.02	0.02	0.10	96	MW	56%	0.51	0.56	0.16	0.01	0.09
2:27	170	MW	100%	0.23	0.06	0.02	0.02	0.10	100	MW	59%	0.33	0.33	0.11	0.01	0.09
2:28	170	MW	100%	0.23	0.06	0.02	0.02	0.10	104	MW	61%	0.16	0.09	0.05	0.01	0.10
Total s Lead Turbine				128	1405	82	2	12	Totals Lag Turbine			115	1402	81	0.5	6

Siemens also provided similar data for warm and hot starts, which were used to determine the following emission rates for starts.

Table B.4 Turbine Start Up Emissions

Pollutant	Cold Start, 150 minutes		Warm Start, 120 minutes		Hot Start, 40 minutes	
	Lead Turbine	Lag Turbine	Lead Turbine	Lag Turbine	Lead Turbine	Lag Turbine
	Lbs	Lbs	Lbs	Lbs	Lbs	Lbs
NOx	128	115	101	91	34	34
CO	1405	1402	1132	1130	368	368
VOC	82	81	66	65	26	26
SOx	2	0.5	1	0	0.2	0.2
PM10	12	6	10	5	2.3	2.3

Table B.5 Turbine Start Up Emissions (combined 2 turbines)

Pollutant	Cold Start, 150 minutes		Warm Start, 120 minutes		Hot Start, 40 minutes	
	Max	Total	Max	Total	Max	Total
	Lbs/hr	Lbs/event	Lbs/hr	Lbs/event	Lbs/hr	Lbs/event
NOx	134	243	134	192	79	68
CO	1,740	2,806	1,846	2,261	738	735
VOC	99	163	97	131	52	51
SOx	2.1	2	2.1	2	2.1	0
PM10	12	19	12	15	12	5

Shut Down Operation

A shutdown is expected to take about 40 minutes to complete. Following is a summary of the estimated emissions during a shutdown.

Table B.6 Turbine Shutdown Emissions (combined 2 turbines)

Pollutant	Shutdown, 20 minutes	
	Max	Total
	Lbs/hr	Lbs/event
NOx	65	46
CO	866	862
VOC	30	28
SOx	2.1	0
PM10	12	3

Daily Emissions

Daily emissions are calculated assuming the following emission rates per turbine:

Table B.7 Maximum Emission Rates (1 Turbine)

	NOx	CO	VOC	PM10	SOx
Normal Operations Controlled (lbs/hr)	18.6	12.5	7	6	1.51
Normal Operations Uncontrolled (lbs/hr)	392	83	51	6	1.51
Cold Start (total lbs)	128	1405	82	12	2
Warm Start (total lbs)	101	1132	66	10	1
Hot Start (total lbs)	34	368	26	2.3	2
Shutdown (total lbs)	23	431	14	1	0.3

Daily emissions are calculated on a per turbine and a per plant basis assuming 1 start up and shutdown in the day, and the remaining hours at full load.

Table B.8 Controlled Daily Emissions (1 Turbine)

		Emissions, lbs				
	Duration	NOx	CO	VOC	PM10	SOx
Cold Start	2.5	128	1405	82	12	2
Normal Operation	20.83	387.4	260.4	145.8	125.0	31.5
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	538.44	2096.38	241.81	137.98	33.75
Warm Start	2	101	1132	66	10	1
Normal Operation	21.33	396.7	266.6	149.3	128.0	32.2
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	520.74	1829.63	229.31	138.98	33.51
Hot Start	0.67	34	368	26	2.3	2
Normal Operation	22.66	421.5	283.3	158.6	136.0	34.2
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	478.48	1082.25	198.62	139.26	36.52

Table B.9 Uncontrolled Daily Emissions (1 Turbine)

		Emissions, lbs				
	Duration	NOx	CO	VOC	PM10	SOx
Cold Start	2.5	128	1405	82	12	2
Normal Operation	20.83	8165.4	1728.9	1062.3	125.0	31.5
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	8316.36	3564.89	1158.33	137.98	33.75
Warm Start	2	101	1132	66	10	1
Normal Operation	21.33	8361.4	1770.4	1087.8	128.0	32.2
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	8485.36	3333.39	1167.83	138.98	33.51
Hot Start	0.67	34	368	26	2.3	2
Normal Operation	22.66	8882.7	1880.8	1155.7	136.0	34.2
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	8939.72	2679.78	1195.66	139.26	36.52

Table B.10 Controlled Daily Emissions, (2 Turbines)

		Emissions, lbs				
	Duration	NOx	CO	VOC	PM10	SOx
Cold Start	2.5	243	2806	163	19	2
Normal Operation	20.83	774.9	520.8	291.6	250.0	62.9
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	1040.88	3757.75	468.62	269.96	65.21
Warm Start	2	192	2261	131	15	2
Normal Operation	21.33	793.5	533.3	298.6	256.0	64.4
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	1008.48	3225.25	443.62	271.96	66.72
Hot Start	0.67	68	735	51	5	0
Normal Operation	22.66	843.0	566.5	317.2	271.9	68.4
Shutdown	0.67	23	431	14	1	0.3
TOTAL	24	933.95	1732.50	382.24	277.92	68.73

Table B.11 Maximum Controlled/Uncontrolled Daily Emissions (1 Turbine)

Pollutant	Operating Scenario	Uncontrolled Daily Emissions	Controlled Daily Emissions
NOx	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	8309.9	531.9
CO	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	3564.9	2096.4
VOC	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	1158.3	241.8
PM10	24 hr normal	144.0	144.0
SOx	24 hr normal	36.2	36.2
NH3	24 hr normal	427.2	427.2

Table B.12 Maximum Controlled Daily Emissions (2 Turbines)

Pollutant	Operating Scenario	Controlled Daily Emissions
NOx	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	1040.9
CO	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	3757.8
VOC	2.5 hr cold start+20.83 hr normal+0.67 hr shutdown	468.6
PM10	24 hr normal	288.0
SOx	24 hr normal	72.4
NH3	24 hr normal	854.4

Monthly Emissions

Monthly Emissions are the basis for offsets for the non-Reclaim pollutants, and are calculated using the highest monthly emission rate for any emission scenario, including normal operation, start ups and shutdowns and commissioning. For SGGS, the highest monthly emission rate for PM10 and SOx is based on assuming 100% normal operation with no start ups or shutdowns. This is because these pollutants are fuel-use based, and start ups and shutdowns use less fuel than normal operation. For VOC, the highest monthly emission scenario includes 1 cold start and 30 hot starts (permit limit), with no warm starts. Commissioning operations do not result in the highest monthly emission rate for any non-Reclaim pollutant (except CO, which does not require offsets). Monthly emissions are based on a 31-day month (744 operating hours). The following tables show the results of the analysis for all pollutants.

Emissions are based on the following factors:

Table B.13 Emission Factors for 30 Day Calculation

	Lbs/event						
Event	Hrs down	Hrs to start	NOx	CO	VOC	PM10	SOx
Cold	72	2.5	120	1405	82	12	2
Warm	10	2	101	1132	66	10	1
Hot	1	0.67	34	368	26	2.3	0.2
Shutdown	0	0.33	23	431	14	1	0.3
normal			18.6	12.5	7	6	1.51

Table B.14 Start Up Scenario

1 Cold Start, 0 Warm Starts, 30 Hot Starts, 31 Shutdowns, and the remaining hours in normal full load

Event	# of events	Hours	NOx	CO	VOC	PM10	SOx
Cold	1	2.5	128	1405	82	12	2
Warm	0	0	0	0	0	0	0
Hot	30	50.1	1020	11040	780	69	6
Shutdown	31	10.23	713	13361	434	46.5	9.3
Normal		681.17	12669.76	8514.63	4768.19	4087.02	1028.57
TOTALS	Lbs/month	744	14530.76	34320.63	6064.19	4214.52	1045.87
	lbs/day		484.36	1144.02	202.14	140.48	34.86

This results in the highest emission rate for VOC on a monthly basis.

Table B.15 Normal Operation Scenario

100% Normal Operation	NOx	CO	VOC	PM10	SOx
Lbs/month	13838.4	9300	5208	4464	1123.44
Lbs/day	461.28	310	173.6	148.8	37.448

This results in the highest emission rate for PM10 and SOx

Table B.16 Monthly Commissioning Emissions

Event	NOx	CO	VOC	PM10	SO2
Individual Commissioning	11114	501260	7698	984	78
Combined Commissioning (1 turbine)	7290	96204	1920	1848	335
Total lbs	18404	597464	9618	2832	413

The total emissions for PM10 and SOx during commissioning will be less than 1 month of normal operation because fuel use is lower during commissioning. For VOC, the total commissioning emissions will be 9618 lbs (7698 + 1920) for 1 turbine. However, the commissioning operation will be conducted over several months, therefore, on average, the monthly VOC emissions during commissioning will be lower than normal operation. CO emissions will be higher during commissioning, however CO offsets are not required because the basin is in attainment.

Appendix C
Commissioning

Each turbine will go through a series of tests during commissioning to prepare for commercial operation. The specific tests to be run on each combustion turbine include the following:

- first fire,
- FSNL and first synchronization,
- manual trips/mechanical overspeed trip test,
- electronic overspeed tests,
- initial synchronization,
- emission-pulsation tune,
- low load,
- dry low NO_x (DLN) burner tune,
- loss of CT processor testing,
- individual CTG/HRSG steam blows,
- combined CTG/HRSG steam blows,
- full load performance and reliability testing, and
- Continuous Emission Monitoring Systems (CEMS) certification

The first four commissioning tests typically each take a day or less to complete. The DLN burner tuning test may take up to 3 days. The last two tests may be run simultaneously and typically last about 2 weeks. In addition, the combustion turbines will be run during the commissioning of both HRSGs and the steam turbine.

SGGS estimates that each turbine will require a maximum of 500 hours of operation during commissioning over a period not to exceed 5 months. A minimum of one turbine start would be needed for each test. The annual frequency of turbine starts during the year when commissioning occurs is not expected to exceed the frequency of turbine starts during operation The fuel flow to each turbine will be monitored during commissioning and used to calculated emissions during this time.

The commissioning period is divided into four main phases:
1. Gas Turbine 1 (GT-1) Commissioning,
2. Gas Turbine 2 (GT-2) Commissioning,
3. Commissioning of both HRSGs and the steam turbine, and
4. Performance and Reliability Testing of the entire plant together.

Conservative, worst-case turbine commissioning emissions were estimated by assuming that the control efficiency of the applicable abatement systems will essentially be zero during the initial commissioning phase. After the combined steam blows are completed, it is assumed that the oxidation and SCR catalysts are installed. The expected control efficiency of the SCR and CO catalyst during normal operation (without duct firing) is approximately 78 percent for NO_x, 80 percent for CO, and 30 percent for VOC.

Therefore, the worst-case commissioning emission rates (at turbine loads greater than 60 percent) would be about 4.5 times the normal NO_x rate, 5 times the normal CO rate, and 1.5 times the normal VOC rate.

The durations and corresponding pollutant emission rates of individual commissioning tests for each combustion turbine generator are shown in the following tables.

Table C.1 Unit 1 and Unit 2 Individual Commissioning

Each turbine will undergo the following tests

Activity	Duration (hours)	CT Load (%)	Fuel Use mmbtu HHV	Exhaust Flow, mmcf/hr	Pollutant Emission Rates, lbs/hr				
					NOx	CO	VOC	SO2	PM10
First fire to FSNL	12	0	4765	12,243,943	41	3,307	41	0.2	5
Green Rotor run in	12	0	4765	12,243,943	41	3,307	41	0.2	5
Manual Trips/Mechanical Overspeed trip test	8	0	3177	12,243,943	41	3,307	41	0.2	5
GT FSNL Lean-Lean Mode	8	0	3177	12,243,943	41	3,307	41	0.2	5
Electronic Overspeed Tests	8	0	3177	12,243,943	41	3,307	41	0.2	5
Unanticipated problems	8	0	3177	12,243,943	41	3,307	41	0.2	5
Initial Synchronization	4	4	1842	14,202,267	63	3,455	51	0.3	5
On-line excitation checks	16	4	7370	14,202,267	63	3,455	51	0.3	5
DLN Tuning/Load Testing – 0%	12	0	4765	12,243,943	41	3,307	41	0.2	5
DLN Tuning/Load Testing – 25%	12	25	9306	23,911,302	125	3,033	87	0.4	5
DLN Tuning/Load Testing – 50%	12	50	13675	35,137,743	62	379	25	0.7	5
DLN Tuning/Load Testing – 75%	12	75	18137	46,601,823	49	13	3	0.9	6
DLN Tuning/Load Testing – 100%			22329	57,374,148	61	17	1	1.1	6

	12	100							
Loss of CT Processor Testing	8	100	14886	57,374,148	61	17	1	1.1	6
CTG 1 steam blow 1	12	4	5527	14,202,267	63	3,455	51	0.3	5
CTG 1 steam blow 2	12	4	5527	14,202,267	63	3,455	51	0.3	5
CTG 1 steam blow 3	12	4	5527	14,202,267	63	3,455	51	0.3	5
CTG 1 steam blow 4	12	4	5527	14,202,267	63	3,455	51	0.3	5
TOTALS	192	///////	136,656	3.91E08	11,114	501,260	7,698	78	984

NOTE – Exhaust flow is at actual O2 levels, not 15% corrected

Table C.2 Unit 1 and 2 Combined Commissioning

Both turbines will operate during the following tests

Activity	Duration (hours)	CT Load (%)	Fuel Use mmbtu HHV	Exhaust Flow, mmcf/hr	Pollutant Emission Rates, lbs/hr per turbine				
					NOx	CO	VOC	SO2	PM10
Combined Steam Blow 1	12	4	11055	14,202,267	63	3,455	51	0.3	5
Combined Steam Blow 1	12	4	11055	14,202,267	63	3,455	51	0.3	5
Load oxidation & SCR catalyst									
Fire for STG prep	12	30	20460	26,285,474	137	1,000	33	0.5	5
Unit base load	24	100	89317	57,374,148	14	3	1	1.1	5.8
Unit base load	24	100	89317	57,374,148	14	3	1	1.1	5.8
Fire for STG testing	24	100	89317	57,374,148	14	3	1	1.1	5.8
Fire for STG testing	24	100	89317	57,374,148	14	3	1	1.1	5.8
Fire for STG testing	24	100	89317	57,374,148	14	3	1	1.1	5.8
Fire for STG base load	24	100	89317	57,374,148	14	3	1	1.1	5.8
Fire for STG base load	24	100	89317	57,374,148	14	3	1	1.1	5.8
Fire for STG base load	24	100	89317	57,374,148	14	3	1	1.1	5.8
Fire for STG base load	24	100	89317	57,374,148	14	3	1	1.1	5.8
Duct Burner Testing	24	110	119149	76,537,106	18	10	1	1.4	6.0
Duct Burner	24	110	119149	76,537,106	18	10	1	1.4	6.0

Testing									
SCR Testing	12	100	44659	57,374,148	14	3	1	1.1	5.8
Stack Testing (RATA)	12	100	44659	57,374,148	14	3	1	1.1	5.8
TOTALS	324	///////	1,151,929	8.1E08	7,290	96,204	1,920	335	1,848

Shaded activities are controlled with SCR and CO catalysts.
NOTE – Exhaust flow is at actual O2 levels, not 15% corrected

Table C.3 Total Commissioning Emissions

Pollutant	Turbine 1 Individual Testing Lbs	Turbine 2 Individual Testing Lbs	Turbine 1 and 2 Combined Testing Lbs	Total lbs
NOx	11,114	11,114	14,579	36,807
CO	501,260	501,260	192,409	1,194,929
VOC	7,698	7,698	3,839	19,235
SO2	78	78	671	827
PM10	984	984	3,696	5,664

Annual emissions are estimated for both a commissioning year, and for a normal year after commissioning. During the commissioning year, normal emissions are prorated assuming 5 months of commissioning and 7 months of normal operation.

Table C.4 Annual Emissions, Commissioning Year

Operating Mode	# of Events	Hours	Emissions, lb/hr					Emissions Per Turbine, total lbs				
			NOx	CO	VOC	PM10	SOx	NOx	CO	VOC	PM10	SOx
Commissioning	1	500						18404.0	597465.0	9618.0	414.0	2832.0
Cold Starts	12	29.16667	121.5	1403	81.5	9.5	1	1417.5	16368.3	950.8	110.8	11.7
Warm Starts	29	58.33333	96	1130.5	65.5	7.5	1	2800.0	32972.9	1910.4	218.8	29.2
Hot Starts	96	64.09667	34	367.5	25.5	2.5	0	3252.7	35157.5	2439.5	239.2	0.0
Shutdowns	137	91.455	23	431	14	1.5	0	3139.5	58831.5	1911.0	204.8	0.0
Normal Operation (w/duct firing)		2333.333	17.7	12.5	6.5	6	1.43	41300.0	29166.7	15166.7	14000.0	3336.7
Normal Operation (no duct firing)		2010.167	14.1	8.5	5	5.75	1.08	28343.4	17086.4	10050.8	11558.5	2171.0
				TOTAL EMISSIONS, 2 TURBINES				197314.0	1574096.7	84094.5	53491.9	16761.0

Table C.5 Annual Emissions, Non-Commissioning Year

Operating Mode	# of Events	Hours	Emissions, lb/hr					Emissions Per Turbine, total lbs				
			NOx	CO	VOC	PM10	SOx	NOx	CO	VOC	PM10	SOx
Cold Starts	20	50	121.5	1403	81.5	9.5	1	6075.0	70150.0	4075.0	475.0	50.0
Warm Starts	50	100	96	1130.5	65.5	7.5	1	4800.0	56525.0	3275.0	375.0	50.0
Hot Starts	164	109.88	34	367.5	25.5	2.5	0	5576.0	60270.0	4182.0	410.0	32.8
Shutdowns	234	156.78	23	431	14	1.5	0	3605.9	67572.2	2194.9	235.2	0.0
Normal Operation (w/duct firing)		4000	17.7	12.5	6.5	6	1.43	70800.0	50000.0	26000.0	24000.0	5720.0
Normal Operation (no duct firing)		3446	14.1	8.5	5	5.75	1.08	48588.6	29291.0	17230.0	19814.5	3721.7
				TOTAL EMISSIONS, 2 TURBINES				271601.1	583436.4	109023.8	90049.3	19089.0

Appendix D

Turbine Air Toxic Emission Calculations

1. New Turbines

Data:

Maximum heat input (w/o duct firing)	2046.3 mmbtu/hr
Maximum annual hours of operation (w/o duct firing)	3791 hrs/yr
Annual Heat Input (w/o duct firing)	7.757E+06 mmbtu/yr
Maximum heat input (w/duct firing)	2662.3 mmbtu/hr
Maximum annual hours of operation (w/duct firing)	4000 hrs/yr
Annual Heat Input (with duct firing)	1.065E+07 mmbtu/yr
Total Annual Heat Input	1.841E+07 mmbtu/yr
Maximum fuel use (25°F, 60% RH w/duct firing)	2.03 mmcf/hr
Annual Hours of Operation	7791 hrs/yr
Total Annual Fuel Use	1.582E+04 mmcf/yr

Pollutant	Emission Factor		Maximum Hourly Emission Rate, lbs/hr	Annual Emissions 1 Turbine, lbs/yr
Ammonia	17.32	Lbs/hr	17.32	1.35E+05
1,3 Butadiene	4.30E-07	Lbs/mmbtu	1.14E-03	7.91E+00
Acetaldehyde	4.00E-05	Lbs/mmbtu	1.06E-01	7.36E+02
Acrolein	3.62E-06	Lbs/mmbtu	9.64E-03	6.66E+01
Benzene	3.26E-06	Lbs/mmbtu	8.68E-03	6.00E+01
Ethylbenzene	3.20E-05	Lbs/mmbtu	8.52E-02	5.89E+02
Formaldehyde	3.60E-04	Lbs/mmbtu	9.58E-01	6.63E+03
Propylene Oxide	2.90E-04	Lbs/mmbtu	7.72E-02	5.34E+02
Toluene	1.30E-04	Lbs/mmbtu	3.46E-01	2.39E+03
Xylene	6.40E-05	Lbs/mmbtu	1.70E-01	1.18E+03
Naphthalene	1.30E-06	Lbs/mmbtu	3.46E-03	2.39E+01
(a)anthracene	2.24E-08	Lbs/mmcf	5.97E-05	4.12E-01

(a)pyrene	1.38E-08	Lbs/mmcf	3.67E-05	2.54E-01
(b)fluoranthene	1.12E-08	Lbs/mmcf	2.98E-05	2.06E-01
(k)fluoranthene	1.09E-08	Lbs/mmcf	2.90E-05	2.01E-01
Chysene	2.50E-08	Lbs/mmcf	6.65E-05	4.60E-01
(a,h)anthracene	2.33E-08	Lbs/mmcf	6.20E-05	4.29E-01
(1,2,3-cd)pyrene	2.33E-08	Lbs/mmcf	6.20E-05	4.29E-01
		Total	Lbs/yr	1.47E+05
			Tons/yr	7.36E+01

Notes:

Emission factors from USEPA AP-42 Table 3.1-3, except 1) Formaldehyde, Benzene, and Acrolein emission factors which are from the Background document for AP-42 Section 3.1, Table 3.4-1 for natural gas turbine with CO catalyst and 2) PAH emission factors (other than naphthalene) which are from the CATEF database for natural gas turbines with SCR and CO catalysts, and 3) ammonia which is based on the required SCR usage.

Appendix E

Modeling

The proposed projects will result in the release of 5 criteria pollutants plus toxics. Modeling is required to determine the impacts on ambient air quality, visibility, and soil deposition from the release of NOx, SOx, CO, and PM10. Also, a health risk assessment is required for toxics. Modeling was conducted on the emissions from the combined new equipment (2 turbines and the aux boiler), as well as on an individual equipment basis for PM10 and the HRA.

Criteria Pollutant Modeling

Start Up/Shutdown and Normal Operations

To determine the turbine impacts during a start up, shutdown, and full load normal operations, a screening model was performed for 4 different temperature/humidity scenarios, at 4 loads per scenario, plus start ups. The unit-based (1 gram/sec) dispersion factors determined for each scenario were then multiplied by the expected emission rate for the given load for each pollutant to determine the case with the maximum impact. Once the maximum impact case was determined, a refined model was performed using those stack parameters and the maximum emission rate per pollutant per averaging time plus the boiler emissions and stack parameters to arrive at the expected project impact.

Table E.1 Results of the Screening Model

		Ambient Temp/RH	Turbine Load	Exhaust Temp °F	Exhaust Velocity (fps)	Emission Rate (g/s)	Maximum X/Q (ug/m3)/(g/s)	Maximum Impact (ug/m3)
NOx	1 hour	See start up model						
	Annual	59°/60%	100%	183.9	66.3	2.263	0.401	0.908
CO	1 hour	See start up model						
	8 hour	25°/60%	100%	183.9	69.5	1.273	2.466	3.138
SO2	1 hour	59°/60%	100%	183.9	66.3	0.186	6.000	1.118
	3 hour	63°/65%	60%	190.2	47.0	0.095	6.904	0.656
	24 hour	59°/60%	100%	183.9	66.3	0.186	1.961	0.366
PM10	24 hour	105°/15%	60%	197.3	43.4	0.725	2.356	1.708
	Annual	105°/15%	60%	197.3	43.4	0.725	0.615	0.446

For short term NOx and CO (1 hour), it was determined that the stack parameters during start up produced the highest impacts. Two different start up scenarios were modeled, one with one turbine starting up and one at full load, and one with both turbines in start up mode simultaneously, as follows:

Table E.2 Start Up Model Inputs

Scenario	Pollutant & Averaging Time	Turbine Load	Exhaust Temp °F	Exhaust Velocity (fps)	Emission Rate (lbs/hr)
1	NOx, 1-hour	One turbine starting at 12% load	200	42.2	99
		One turbine normal operation 100% load w/duct firing	183.9	66.3	18.3
	CO, 1-hour	One turbine starting at 12% load	200	42.2	1376
		One turbine normal operation 60% load no duct firing	192.9	50.1	10.1
2	NOx, 1-hour	Both turbines starting at 30% load	192.9	42.2	67
	CO, 1-hour		192.9	42.2	923

The refined model was performed using the following emission rates:

Table E.3 Modeled Emission Rates Normal Operation, Turbine and Boiler

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions in pounds – Entire Period: Both CTG/HRSGs	New Auxiliary Boiler
1-hour	NOx: Cold or warm start up hour (both turbines)* CO: Warm start up hour (both turbines)* SOx: Full-load turbine operation with duct firing (both turbines) at 25ºF ambient temperature. All: Aux boiler operation at 100% fuel input rate	NOx	134.2	0.69
		CO	1,846	2.38
		SOx	3.0	0.04
3-hour	SOx: Continuous full-load turbine operation with duct firing (both turbines) at 25ºF ambient temperature. All: Continuous aux boiler operation at 100% fuel input rate	SOx	9.0	0.12
8-hour	CO: One cold start, one hot start, one shutdown, and remainder of period at full load operation with full duct firing (both turbines) at 25°F ambient temperature All: Continuous aux boiler operation at 100% fuel input rate	CO	4,494	19.01
24-hour	NOX: One cold start, one	PM10	288	7.71

Averaging Time	Worst-case Emission Scenario	Pollutant	Emissions in pounds – Entire Period	
			Both CTG/HRSGs	New Auxiliary Boiler
	shutdown, one hot start and remainder of period at full load operation with full duct firing (both turbines) at 25°F ambient temperature SOX, PM10: Continuous full-load turbine operation with duct firing (both turbines) at 25ºF ambient temperature. All: Continuous aux boiler operation at 100% fuel input rate for 12 hours of the period.	NOx	1,107	16.64
		SOx	72	0.92
Annual	SOx, NOx, PM10: Both turbines operate at full load for 7,446 hours at 63°F (4,000 hours with duct firing), 164 hot starts, 50 warm starts, 20 cold starts and 234 shutdowns All: Aux boiler operation at 100% fuel input rate for 4,000 hours	NOx	272,049	2,774
		PM10	90,165	1,284
		SOx	19,168	154

The turbine stack parameters used in the refined modeling were as follows:

Table E.4 Modeled Stack Parameters, Turbine

		Stack Diameter ft	Stack Ht, ft	Stack Temp, deg F	Exhaust velocity, fps
NOx	1 hour	See start up model			
	Annual	19	150.5	183.9	66.3
CO	1 hour	See start up model			
	8 hour	19	150.5	183.9	69.5
SO_2	1 hour	19	150.5	183.9	66.3
	3 hour	19	150.5	190.2	47.0
	24 hour	19	150.5	183.9	66.3
	Annual	19	150.5	183.9	66.3
PM_{10}, $PM_{2.5}$	24 hour	19	150.5	197.3	43.4
	Annual	19	150.5	197.3	43.4

The boiler stack parameters used in the modeling were as follows:

Table E.5 Modeled Stack Parameters, Boiler

		Stack Diameter ft	Stack Ht, ft	Stack Temp, deg F	Exhaust Velocity, fps
NO_X	1 hour	3	150.5	265.0	36.0
	annual	3	150.5	265.0	36.0
CO	1 hour	3	150.5	265.0	36.0
	8 hour	3	150.5	265.0	36.0
SO_2	1 hour	3	150.5	265.0	36.0
	3 hour	3	150.5	265.0	36.0
	24 hour	3	150.5	265.0	36.0
	Annual	3	150.5	265.0	36.0
PM_{10}, $PM_{2.5}$	24 hour	3	150.5	265.0	36.0
	Annual	3	150.5	265.0	36.0

The results of the refined modeling for start up, shutdowns, and normal operations show compliance with the applicable air quality standard or significant increase.

Table E.6 Model Results – Start up/Shutdown and Normal Operation

Pollutant	Averaging Period	Maximum Predicted Impact (ug/m3)	Background Concentration (ug/m3) (1)	Total Concentration (ug/m3)	NAAQS (ug/m3)	CAAQS (ug/m3)
NO2	1-hour(4)	98.16	229.09	327.52	NA	470(2)
	Annual	0.90	67.59	68.5	100	100(2)
CO	1-hour(4)	1335	5830	7165	40,000	23,000
	8-hour	88.56	5145	5233.6	10,000	10,000
SO2	1-hour	1.23	62.75	64.0	NA	655
	3-hour	1.43	41.83	43.3	1300	NA
	24-hour	0.40	39.22	39.6	365	105
	Annual	0.06	10.46	10.5	80	NA
PM10	24-hour	1.90	164	N/A	NA	2.5(3)
	Annual	0.46	63.3	N/A	NA	0.50(3)

(1) Background concentrations are the maximum recorded values from the Upland,, Fontana, San Bernardino 4th Street, and Riverside Rubidoux station for 1994, 1995, 1197, 1998, and 1999
(2) In February 2007, CARB approved new CAAQS for NO2, the new standards are 338 ug/m3 (1 hour) and 56 ug/m3 (annual). The standards are expected to take effect in late 2007..
(3) Since the basin is non-attainment for PM10, the comparison is project impact to allowable significant change
(4) Peak 1 hour NO2 and CO are obtained from start up scenario 2 – 2 turbines starting at 30% load.

Commissioning

NOx and CO during commissioning was modeled for both maximum single turbine emission rates as well as maximum emissions from both turbines during the combined steam blows.

Table E.7 Modeled Emission Rates, Commissioning

Modeling Scenario	Pollutant	Averaging Period	Total Emissions lbs	Stack Temp, °F	Exhaust Velocity, fps	Exhaust Flow, mmcf/hr
Single turbine commissioning	NOx	1 hour	125	200	32.8	33.5
	CO	1 hour	3,307	200	32.6	33.3
		8 hour	26,456	200	32.6	33.3
Combined Steam Blows	NOx	1 hour	63	200	35.2	35.9
	CO	1 hour	3,455	200	35.2	35.9
		8 hour	27,640	200	35.2	35.9

TableE.8 Model Results, Commissioning

Modeling Scenario	Pollutant	Averaging Period	Maximum Predicted Impact, ug/m3	Background Concentration, ug/m3	Total Concentration, ug/m3
Single turbine commissioning	NOx	1 hour	80.59	229.09	310
	CO	1 hour	3,190.95	5,830	9,021
		8 hour	1,264.32	5,145	6,409
Combined Steam Blows	NOx	1 hour	76.21	229.09	305
	CO	1 hour	4,797.69	5,830	10,628
		8 hour	1,783.68	5,145	6,929

Background concentrations are the maximum recorded values from the Upland,, Fontana, San Bernardino 4th Street, and Riverside Rubidoux station for 1994, 1995, 1197, 1998, and 1999.

PSD, Deposition, and Visibility Analysis

The analysis for PSD, deposition, and visibility was performed for both near field Class I areas (less than 50 km), as well as far field Class I areas (further than 50 km). All the far-field modeling was done using CALPUFF, while the near-field modeling was done using AERMOD (PSD), VISCREEN (visibility), and CALPUFF (deposition). Note that the applicant did not perform a soils and vegetation analysis, but instead referred to the results of the deposition analysis in concluding that the soil impacts would be minimal.

Table E.9 Modeled Emission Rates/Stack Parameters for PSD, Deposition, and Visibility

Distance from the Project	Class I Area	Class I Area Air Quality Impact Analysis	Emission Inputs	Stack Parameters
Within 50 km	Cucamonga Wilderness Area San Gabriel Wilderness Area	PSD	Same as Table E.3 for given pollutant and averaging time	Same as Tables E.4 and E.5 for given pollutant and averaging time
		Deposition	Same as Table E.3 for annual average NOx, and SO2	Same as Tables E.4 and E.5 for annual average NOx, and SO2
		Visibility	Start up NOx – Same as Table E.2, Base Load NOx - 59.9 lbs/hr (2 turbines), Base Load PM10 – 12 lbs/hr (2 turbines)	Same as Table E.3 for base load. Same as Table E.2 for start up
Beyond 50 km	San Gorgonio Wilderness Area Agua Tibia Wilderness Area San Jacinto Wilderness Area Joshua Tree National Park	PSD	Same as Table E.3 for annual average PM10, NOx, and SO2	Same as Tables E.4 and E.5 for annual average PM10, NOx, and SO2
		Deposition	Same as Table E.3 for annual average NOx, and SO2	Same as Tables E.4 and E.5 for annual average NOx, and SO2
		Visibility	Same as Table E.3 for 24 hour PM10, NOx, and SO2	Same as Tables E.4 and E.5 for 24 hour PM10, NOx , and SO2

Table E.10 Results for Far Field Visibility Analysis (CALPUFF)

	Level of Acceptable Change = 5%		
Predicted % Change in Light Extinction Coefficient			
Class I Area	2001	2002	2003
San Gorgonia Wilderness	7.82*	4.77	3.15
San Jacinto Wilderness	2.02	2.90	2.16
Agua Tibia Wilderness	1.88	1.87	2.43
Joshua Tree National Park	2.82	1.45	2.70

** 2 days in 2001 exceeded 5% extinction rate threshold, on March 1 and July 7 @ 6.1% and 7.82% respectively..*

Table E.11 Results for Near-Field Visibility Analysis (VISCREEN)

Class I Area	Emissions Scenario	Modeled Parameter	Sky		Terrain		Significance Threshold
			10°	140°	10°	140°	

Cucamonga Wilderness	Normal Operations	Color Difference Index (Delta E)	0.500	0.282	1.559	0.062	2
		Contrast (C)	0.009	-0.005	0.006	0	0.05
	Start Up	Color Difference Index (Delta E)	1.222	0.915	1.502	0.125	2
		Contrast (C)	0.004	-0.009	0.006	0.001	0.05
San Gabriel Wilderness	Normal Operations	Color Difference Index (Delta E)	0.228	0.102	0.458	0.027	2
		Contrast (C)	0.004	-0.002	0.003	0	0.05
	Start Up	Color Difference Index (Delta E)	0.487	0.335	0.433	0.076	2
		Contrast (C)	0.002	-0.004	0.003	0.000	0.05

Table E.12 Results for Near and Far Field Deposition Analysis (CALPUFF)

	Nitrogen	Sulfur
Class I Significance Level (kg/ha/yr)	0.005	0.005
Maximum Predicted Class I Area Impacts (kg/ha/yr)		
Cucamonga Wilderness	0.0004	0.0001
San Gabriel Wilderness	0.0001	0.0001
San Gorgonio Wilderness	0.0011	0.0005
San Jacinto Wilderness	0.0006	0.0002
Agua Tibia Wilderness	0.0003	0.0001
Joshua Tree NP	0.0006	0.0002

Table E.13 Results for Near Field Ambient Air Quality Analysis (AERMOD)

	NOx Annual	SO2 3-hr	SO2 24-hr	SO2 Annual	PM10 24-hr	PM10 Annual
Proposed Class I SIL (ug/m3)	0.10	1.00	0.20	0.10	0.30	0.20
Maximum Predicted Class I Area Impacts (ug/m3)						
Cucamonga Wilderness	0.0006	0.0075	0.0014	0.00004	0.0055	0.0002
San Gabriel Wilderness	0.0008	0.0086	0.0018	0.00006	0.0073	0.0003

Table E.14 Results for Far Field Ambient Air Quality Analysis (CALPUFF)

	NOx Annual	SO2 3-hr	SO2 24-hr	SO2 Annual	PM10 24-hr	PM10 Annual
Proposed Class I SIL (ug/m3)	0.10	1.00	0.20	0.10	0.30	0.20
Maximum Predicted Class I Area Impacts (ug/m3)						
San Gorgonio Wilderness	0.019	0.026	0.008	0.001	0.095	0.009
San Jacinto Wilderness	0.006	0.013	0.003	0.0002	0.031	0.003
Agua Tibia Wilderness	0.002	0.009	0.002	0.0001	0.031	0.001
Joshua Tree NP	0.003	0.009	0.002	0.0002	0.026	0.002

Air Toxics Health Risk Assessment (HRA)

A Tier 4 HRA was performed for the project using CARB's Hotspots Analysis and Reporting Program (HARP) (CARB, 2003). Toxic emissions from the turbines and boiler were calculated based on the emission factors and methodology shown in Appendix D.

Table E.15 Modeled Emission Rates For HRA

Pollutant	Turbine Emissions (lbs/yr/turbine)	Boiler Emissions (lbs/yr)
1,3 Butadiene	7.91E+00	N/A
Acetaldehyde	7.36E+02	6.88E-01
Acrolein	6.66E+01	6.00E-01
Benzene	6.00E+01	1.29E+00
Ethylbenzene	5.89E+02	1.53E+00
Formaldehyde	6.63E+03	2.73E+00
Hexane	N/A	1.02E+00
Naphthalene	2.39E+01	6.66E-02
Propylene Oxide	5.34E+02	N/A
Toluene	2.39E+03	5.89E+00
Xylene	1.18E+03	4.38E+00
Ammonia	1.35E+05	N/A
Propylene	N/A	5.89E+00
(a)anthracene	4.12E-01	4.00E-04
(a)pyrene	2.54E-01	2.67E-04
(b)fluoranthene	2.06E-01	4.00E-04
(k)fluoranthene	2.01E-01	4.00E-04
Chysene	4.60E-01	4.00E-04
(a,h)anthracene	4.29E-01	2.67E-04
(1,2,3-cd)pyrene	4.29E-01	4.00E-04
7,12(a)anthracene	N/A	3.55E-03
3-methlychloranthrene	N/A	4.00E-04

Table E.16 Modeled Stack Parameters For HRA

Parameter	Turbines	Boiler
Stack Diameter, ft	19	3
Stack Height, ft	150.5	150.5
Stack Temp, deg F	183.9	265
Stack Velocity, ft/s	69.5	36.0

Table E.17 Model Results – HRA

Receptor	Cancer Risk (per million)	Chronic Hazard Index	Acute Hazard Index
Residential	0.352	0.018	0.065

Appendix F

Individual Permit Unit Modeling

Modeling was also performed on an individual permit unit basis for PM10 and the HRA.

Table E.18 Model Inputs, Individual Unit 24-Hour PM10

	Stack Diameter ft	Stack Ht, ft	Stack Temp, deg F	Exhaust velocity, fps	Emission Rate, lbs/24hr/source
Turbines	19	150.5	183.9	66.3	288
Boiler	3	150.5	265.0	36.0	7.71

Table E.19 Model Results, Individual Unit 24-Hour PM10

Permit Unit	Maximum Predicted Concentration, ug/m3
Turbine 1	0.94
Turbine 2	1.12
Aux Boiler	0.96

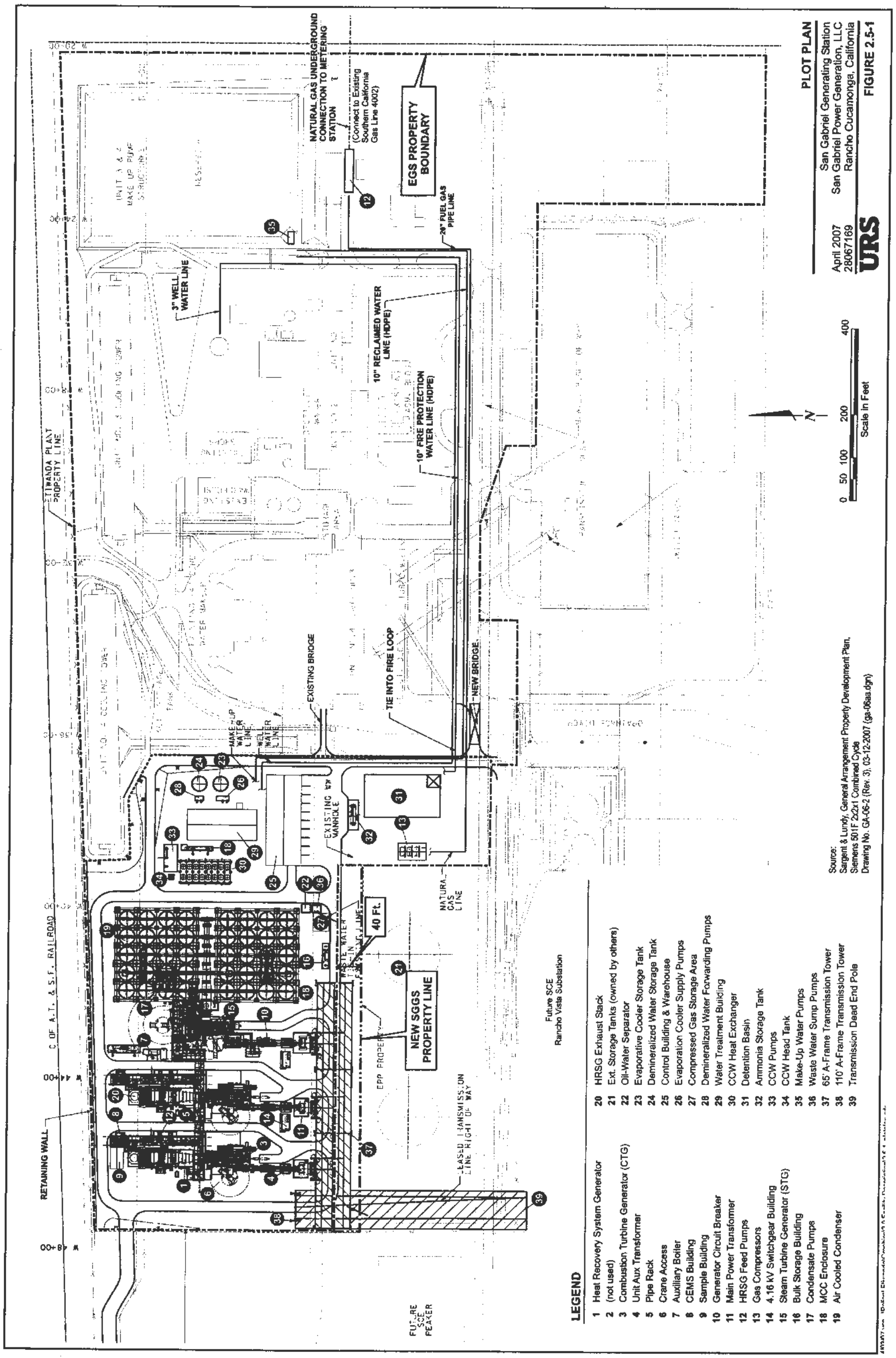
Table E.20 Model Inputs, Individual Unit HRA

	Stack Diameter ft	Stack Ht, ft	Stack Temp, deg F	Exhaust velocity, fps	Emission Rate lbs/yr/source
Turbines	19	150.5	183.9	66.3	Same as Table E.15
Boiler	3	150.5	265.0	36.0	Same as Table E.15

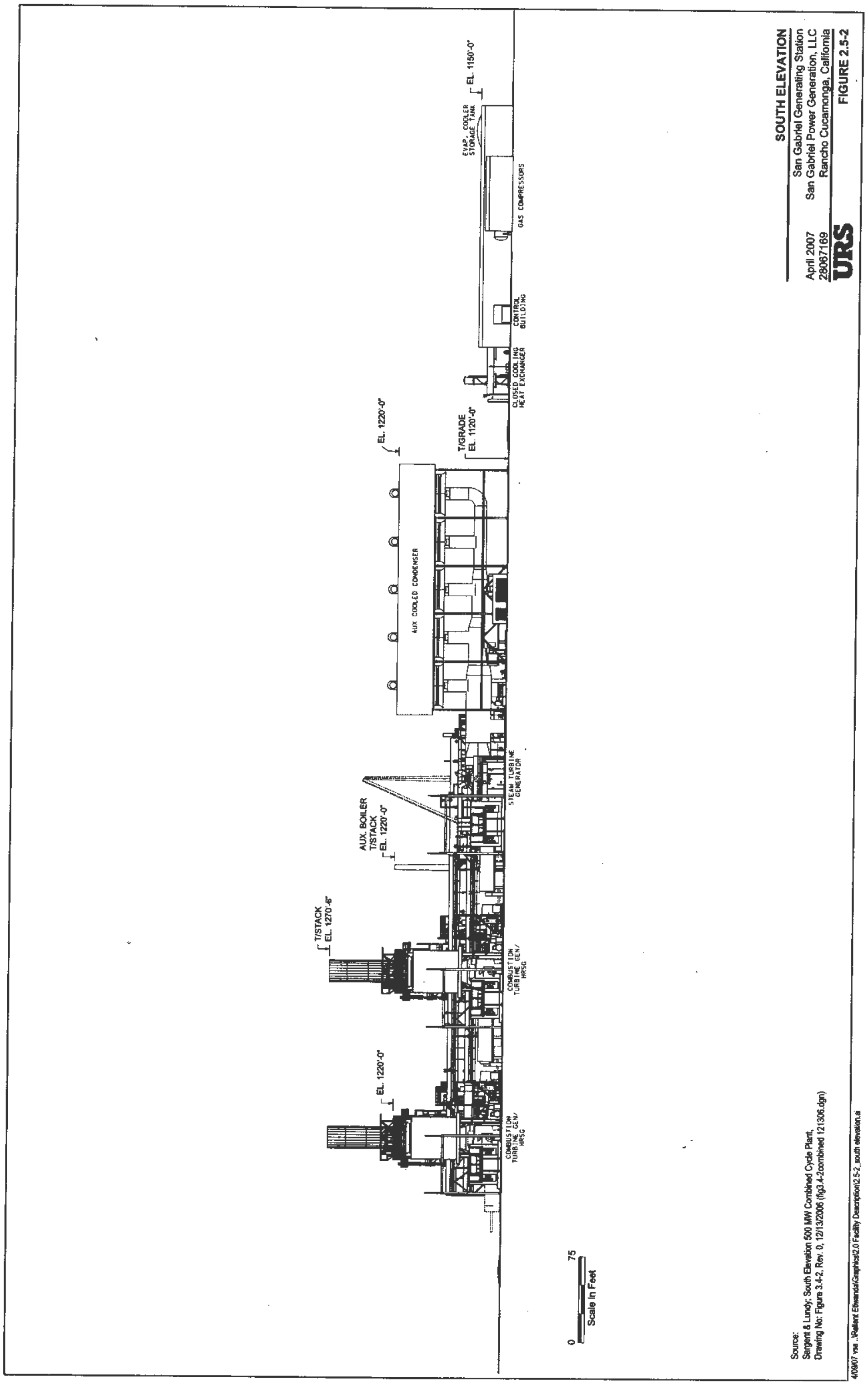
Table E.21 Model Results, Individual Unit HRA

Permit Unit	Risk Type	Maximum Risk	Year of Data
Turbine 1	Cancer Risk per Million	0.131	1997
Turbine 2		0.114	1997
Aux Boiler		0.093	1997
Turbine 1	Chronic	0.008	1997
Turbine 2		0.010	1997
Aux Boiler		0.0004	1997
Turbine 1	Acute	0.032	1995
Turbine 2		0.038	1995
Aux Boiler		0.003	1995

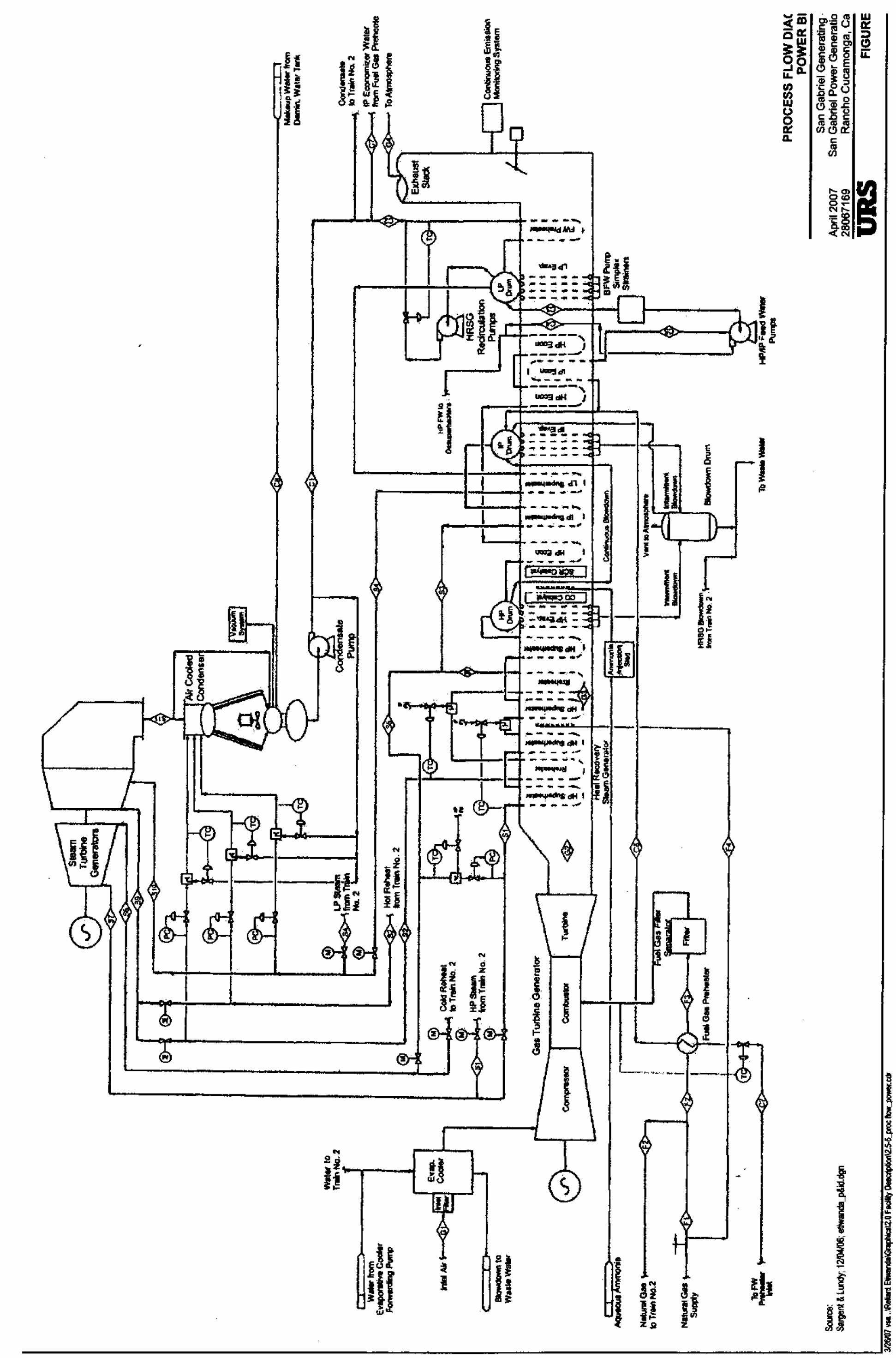
Appendix G – Facility Plot Plan



Appendix H – Elevation View



Appendix I – Process Flow



Appendix J

Nearest Schools

The following schools (K-12) were determined to be located within the vicinity of the proposed project:

	School	Location	Approx Distance from SGGS
1	Sacred Heart Parish School	12704 Foothill Blvd, Etiwanda	1.2 miles N
3	West Heritage Elementary	13690 W Constitution Way, Fontana	1.9 miles NE
4	Almond Elementary	8172 Almond Ave, Fontana	2.0 miles NE
5	Redwood Elementary	8570 Redwood Ave, Fontana	2.3 miles E
6	East Heritage Elementary	14250 E Constitution Way, Fontana	2.3 miles NE
7	Grapeland Elementary	7171 Etiwanda Ave, Etiwanda	2.34 miles N
8	Heritage Intermediate	13766 S Heritage Cir, Fontana	2.42 miles NE
9	Terra Vista Elementary	7497 Mountainview Dr, Rancho	2.52 miles NW
10	Live Oak Elementary	9522 Live Oak Ave, Fontana	2.58 miles E

Appendix K

Facility Reported Emissions

The following tables summarize the annual emissions reported to AQMD by the facility:

Pollutant	Emissions, tpy	
	2002-03	2003-04
NOx	115	17.45
CO	17	36.85
VOC	10	2.56
PM10	15	2.38
SOx	2	0.79

Appendix L

Major Source Determinations

1. 40CFR 64 CAM

For purposes of 40CFR 64, CAM Regulation, a major source is defined as a source or group of sources with pre-control potential to emit (PTE) emission levels exceeding those in Part 70 and Part 71.

Pollutant	Emissions, tpy			Major Source?
	Turbines[1]	Utility Boilers[2]	Threshold	
NOx	3,434	1,743	10	Y
CO	464	5,028	50	Y
VOC	412	1,901	10	Y
PM10	53	96	70	Y
SOx	13	15	100	N

(1) from Table 3.2, uncontrolled rates X 8760 hours per year.
(2) Utility boiler uncontrolled emission factors taken from A/N 375847 as follows: NOx 199 lbs/hr, CO 574 lbs/hr, VOC 217 lbs/hr, PM10 11 lbs/hr, SOx 1.70 lbs/hr

2. 40CFR 63 - NESHAPS

For NESHAPS, a major source is defined as a site that emits or has the potential to emit 10 tpy or more of any single HAP, or 25 tpy or more of any combination of HAPs (HAP being defined as one of the 112 air contaminants listed in the Section .

Auxiliary Boiler

Toxic Emissions are based on the Ventura County APCD AB2588 External Combustion Emission Factors, M
2001, except PAH emissions (other than naphthalene), which are based on AP-42 Section 1.4 Natural Gas Ex
Combustion.

Boiler Data:

Maximum heat input	56 mmbtu/hr
Maximum fuel use	0.056 mmcf/hr (based on 1008.6 btu/cf)
Annual hours of operation	4000 hours

Pollutant	Emission Factors lbs/mmcf	Emission Factor lbs/mmbtu	Emissions (lbs/hr)	Emissions (lbs/yr)
Acetaldehyde	0.0031	3.07E-06	1.72E-04	6.88E-01
Acrolein	0.0027	2.68E-06	1.50E-04	6.00E-01
Benzene	0.0058	5.75E-06	3.22E-04	1.29E+00
Ethylbenzene	0.0069	6.84E-06	3.83E-04	1.53E+00
Formaldehyde	0.0123	1.22E-05	6.83E-04	2.73E+00
Hexane	0.0046	4.56E-06	2.55E-04	1.02E+00
Naphthalene	0.0003	2.97E-07	1.67E-05	6.66E-02
Toluene	0.0265	2.63E-05	1.47E-03	5.89E+00
Xylene	0.0197	1.95E-05	1.09E-03	4.38E+00
Propylene	0.5300	5.25E-04	2.94E-02	5.89E+00
(a)anthracene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
(a)pyrene	1.20E-07	1.19E-09	6.66E-08	2.67E-04
(b)fluoranthene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
(k)fluoranthene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
Chysene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
(a,h)anthracene	1.20E-06	1.19E-09	6.66E-08	2.67E-04
(1,2,3-cd)pyrene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
7,12(a)anthracene	1.60E-05	1.58E-08	8.88E-07	3.55E-03
3-methlychloranthrene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
Total PAH’s (other than naphthalene)			1.62E-06	6.48E-03
Total			3.39E-02	2.41E+01

Existing Boilers 3 and 4

Toxic Emissions are based on the Ventura County APCD AB2588 External Combustion Emission Factors, M
2001, except PAH emissions (other than naphthalene), which are based on AP-42 Section 1.4 Natural Gas Ex
Combustion.

Boiler Data:

Maximum heat input	2900 mmbtu/hr
Maximum fuel use	2.88 mmcf/hr (based on 1008.6 btu/cf)
Annual hours of operation	8760 hours

Pollutant	Emission Factors lbs/mmcf	Emission Factor lbs/mmbtu	Emissions (lbs/hr)	Emissions (lbs/yr)
Acetaldehyde	0.0009	8.92E-07	2.59E-03	2.27E+01
Acrolein	0.0008	7.93E-07	2.30E-03	2.01E+01
Benzene	0.0017	1.69E-06	4.90E-03	4.29E+01
Ethylbenzene	0.0020	1.98E-06	5.74E-03	5.03E+01
Formaldehyde	0.0036	3.57E-06	1.04E-02	9.07E+01
Hexane	0.0013	1.29E-06	3.74E-03	3.28E+01
Naphthalene	0.0003	2.97E-07	8.61E-04	7.54E+00
Toluene	0.0078	7.73E-06	2.24E-02	1.96E+02
Xylene	0.0058	5.75E-06	1.67E-02	1.46E+02
Propylene	0.0155	1.54E-05	4.47E-02	3.91E+02
(a)anthracene	1.80E-06	1.78E-09	5.16E-06	4.52E-02
(a)pyrene	1.20E-07	1.19E-09	3.45E-06	3.02E-02
(b)fluoranthene	1.80E-06	1.78E-09	5.16E-06	4.52E-02
(k)fluoranthene	1.80E-06	1.78E-09	5.16E-06	4.52E-02
Chysene	1.80E-06	1.78E-09	5.16E-06	4.52E-02
(a,h)anthracene	1.20E-06	1.19E-09	3.45E-06	3.02E-02
(1,2,3-cd)pyrene	1.80E-06	1.78E-09	5.16E-06	4.52E-02
7,12(a)anthracene	1.60E-05	1.58E-08	4.58E-05	4.01E-01
3-methlychloranthrene	1.80E-06	1.78E-09	5.16E-06	4.52E-02
Total PAHs (other than naphthalene)			8.37E-05	7.33E-01
Total			1.14E-01	1.00E+03

Total TAC Facility Emissions*

Turbine 1 (tpy)	Turbine 2 (tpy)	Aux Boiler (tpy)	Boiler 3 (tpy)	Boiler 4 (tpy)	Total (tpy)
6.11	6.11	0.012	0.50	0.50	13.23

*not including ammonia

Appendix M

Summary of PM10 Test Results

The following test results were used as supporting data for determining the PM10 emission rate for the SGGS facility. AQMD source test staff reviewed the full test report for the Bighorn facility and found the test was conducted properly and the results are valid.

Facility	Turbine	Unit	Result	Test Method	Approximate lbs/MW-hr
Delta Energy Center, 3 CTs, 1 ST, DBs, 880 MW	Siemens 501-FD	1	4.575 lbs/hr	4 hr test/EPA Methods 201A/202	0.0156
		2	5.316	4 hr test/EPA Methods 201A/202	0.0181
		3	5.858	4 hr test/EPA Methods 201A/202	0.02
Calpine Sutter Energy Center 2 CTs, 1 ST, DBs, 500 MW	Siemens 501 FD	1	0.936	4 hr test/EPA Methods 201A/202	0.00374
		2	1.658	4 hr test/EPA Methods 201A/202	0.00663
Florida Power and Light Company - Blythe Energy 2 CTs, 1 ST, DBs, 520 MW	Siemens F class V84.3A	1	2.32	2 hr test/EPA Methods 5/202	0.00892
Calpine Corp - Metcalf Energy Center 2 CTs, 1 ST, DBs, 635 MW	Siemens 501 F	1	5.549	test duration unpsecified/EPA Methods 201A/202	0.0175
		2	5.406	test duration unpsecified/EPA Methods 201A/202	0.0170
Big Horn, 2 CTs, 1 ST, DBs, 580 MWs	Siemens 501-FD	1	5.42	Highest of three 2-hour tests EPA Methods 201A/202	0.0189
		2	5.33	Highest of three 2-hour tests EPA Methods 201A/202	0.0184

Appendix N

RECLAIM Reporting Emission Factor Determination

The facility is required to report NOx emissions based on the emission factor in the permit for any operation which occurs before initial certification of the CEMS (after certification missing data procedures are used). The factor should be based on expected NOx emissions with little or no emission controls as an incentive for the facility to certified its CEMS. The facility will most likely certified its CEMS during or shortly after commissioning is completed. Therefore, the factor will be based on the total expected emissions during the first part of commissioning as follows:

Total Turbine Emissions During Individual Commissioning	Total Turbine Fuel Use During Individual Commissioning[1]	Reclaim Reporting Factor
11,114 lbs	137 mmcf	81 lbs/mmcf

1 based on 136,656 mmbtu/1000 mmbtu/cf

The facility is required to measure and record fuel use during commissioning.

Appendix O

Summary of Applications and Processing Fees

The following table summarizes the application submittals and associated processing fees.

A/N	Submittal Date	Equip	Bcat	Fee Sch	Fee
468530	May 1, 2007	Gas turbine #1	013009	D	$3,701.25
468531	May 1, 2007	SCR/CO catalyst #1	81	C	2,681.75
468533	May 1, 2007	Gas Turbine #2	013009	D	3,701.25
468534	May 1, 2007	SCR/CO catalyst #2	81	C	2,681.75
468535	May 1, 2007	Auxiliary Boiler	011005	E	4,255.32
468536	May 1, 2007	Ammonia storage tank	210900	A	1,063.82
468529	May 1, 2007	Title V Revision	555009	C	1,394.73
		Expedited Processing			9,042.57
		Total			$28,522.44

The facility will also be required to pay a fee for the public notice, and for the modeling review. There may also be a fee if there is a request for a public hearing. These fees will be billed to the facility after the permit is issued:

Public Notice	$1,614.36
Modeling Review(1)	3,651.67
Sub-Total	$5,266.03
Public Hearing Fee(2)	2,218.48

(1) Plus T&M @ $104.43/hr if above 35 hours

(2) Plus $689.76/hr

Total submitted $33,659.81 (Check # 1030724)

Appendix P

Auxiliary Boiler Criteria Pollutant Calculations

Boiler emissions of NOx, CO, and VOC are based on the manufacturer guaranteed emission rates as follows:

Table A.1 Manufacturer Guaranteed Emissions

Pollutant	Guarantee	Uncontrolled Emissions[1]
NOx	9 ppm @ 3% dry	45 ppm
CO	25 ppm @ 3%	125 ppm
VOC	3 ppm @ 3%	15 ppm

1 assuming 80% control from the burner

Emissions of PM10 and SOx are based on default emission factors from Form B-1as follows:

Table A.2 Form B-1 Emission Factors

Pollutant	Emission Factor
PM10	7.6 lbs/mmcf
SOx	0.60 lbs/mmcf

Boiler Data:

Maximum heat input	56 mmbtu/hr
Maximum fuel use	0.056 mmcf/hr (based on 1008.6 btu/cf)
Annual hours of operation	4000 hours

Calculations:

NOx
Lbs/mmbtu = (8710*1.16 cf/mmbtu * 9 ppm * 46 lbs/lb-mol)/ 380 lb-mol/cf
= 0.0110 lbs/mmbtu

CO
Lbs/mmbtu = (8710*1.16 cf/mmbtu * 25 ppm * 28 lbs/lb-mol)/ 380 lb-mol/cf
= 0.0186 lbs/mmbtu

VOC
Lbs/mmbtu = (8710*1.16 cf/mmbtu * 3 ppm * 16 lbs/lb-mol)/ 380 lb-mol/cf
= 0.00128 lbs/mmbtu

Controlled Emissions

Pollutant	Emissions		
	Lbs/hr	Lbs/day	Lbs/yr*
NOx	0.62	14.9	2,480
CO	1.04	25.0	4,160
VOC	0.072	1.7	288
PM10	0.43	10.3	1,720
SOx	0.034	0.82	136

**Based on 4,000 hours per year operation*

Uncontrolled Emissions

Pollutant	Emissions	
	Lbs/hr	Lbs/day
NOx	3.1	74.4
CO	5.2	124.8
VOC	0.36	8.64
PM10	0.43	10.3
SOx	0.068	0.82

30 Day Average Emissions are based on 744 hours of operation per month at full load.

Pollutant	Emissions	
	Lbs/month	30 Day Average
NOx	461.3	15.4
CO	773.8	25.8
VOC	53.6	1.9
PM10	319.9	10.7
SOx	25.3	0.84

RECLAIM Reporting Emission Factor

The facility is required to report NOx emissions based on the emission factor in the permit for any operation v occurs before initial certification of the CEMS (after certification missing data procedures are used). The fact should be based on expected NOx emissions with little or no emission controls as an incentive for the facility certify its CEMS. Therefore, the factor will be based on estimated uncontrolled NOx emissions.

Uncontrolled NOx	Fuel Use	Reporting Factor
3.1 lbs/hr	0.056 mmcf/hr	55 lbs/mmcf

Appendix Q

Boiler Air Toxic Emissions Calculations

Toxic Emissions are based on the Ventura County APCD AB2588 External Combustion Emission Factors, M 2001, except PAH emissions (other than naphthalene), which are based on AP-42 Section 1.4 Natural Gas Ex Combustion.

Boiler Data:

Maximum heat input	56 mmbtu/hr
Maximum fuel use	0.056 mmcf/hr (based on 1008.6 btu/cf)
Annual hours of operation	4000 hours

Pollutant	Emission Factors lbs/mmcf	Emission Factor lbs/mmbtu	Emissions (lbs/hr)	Emissions (lbs/yr)
Acetaldehyde	0.0031	3.07E-06	1.72E-04	6.88E-01
Acrolein	0.0027	2.68E-06	1.50E-04	6.00E-01
Benzene	0.0058	5.75E-06	3.22E-04	1.29E+00
Ethylbenzene	0.0069	6.84E-06	3.83E-04	1.53E+00
Formaldehyde	0.0123	1.22E-05	6.83E-04	2.73E+00
Hexane	0.0046	4.56E-06	2.55E-04	1.02E+00
Naphthalene	0.0003	2.97E-07	1.67E-05	6.66E-02
Toluene	0.0265	2.63E-05	1.47E-03	5.89E+00
Xylene	0.0197	1.95E-05	1.09E-03	4.38E+00
Propylene	0.5300	5.25E-04	2.94E-02	5.89E+00
(a)anthracene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
(a)pyrene	1.20E-07	1.19E-09	6.66E-08	2.67E-04
(b)fluoranthene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
(k)fluoranthene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
Chysene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
(a,h)anthracene	1.20E-06	1.19E-09	6.66E-08	2.67E-04
(1,2,3-cd)pyrene	1.80E-06	1.78E-09	9.99E-08	4.00E-04
7,12(a)anthracene	1.60E-05	1.58E-08	8.88E-07	3.55E-03
3-methlychloranthrene	1.80E-06	1.78E-09	9.99E-08	4.00E-04