

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 1
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

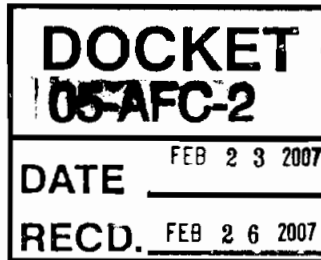
**FINAL DETERMINATION OF COMPLIANCE FOR  
WALNUT CREEK ENERGY, LLC**

**COMPANY NAME AND ADDRESS**

Walnut Creek Energy, LLC  
 % Edison Mission Energy  
 18101 Von Karman Avenue  
 Irvine, CA 92612  
 Contact: Mr. Thomas J. McCabe, Jr  
 AQMD Facility ID: 146536

**EQUIPMENT LOCATION**

911 Bixby Drive  
 City of Industry, CA 91744



**EQUIPMENT DESCRIPTION**

Section H of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
<b>Process 1: INTERNAL COMBUSTION</b>					
<b>System 1: GAS TURBINES, POWER GENERATION</b>					
GAS TURBINE, UNIT NO. 1, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F WITH WATER INJECTION,  WITH A/N 450894           GENERATOR, 104 MW	D1	C3	NOX: MAJOR SOURCE	<p><b>CO:</b> 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; <b>CO:</b> 2000 PPMV (5) [Rule 407]</p> <p><b>NOX:</b> <del>449</del> <u>15</u> PPMV NATURAL GAS (8) [40CFR60 Subpart GG KKKK]; <b>NOX:</b> 123.46 LB/MMCF (1) [Rule 2012] <b>NOX</b> <del>40.86</del> <u>10.29</u> LB/MMCF NATURAL GAS (1)[Rule 2012] <b>NOX</b> 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT]</p> <p><b>VOC:</b> 2.0 PPMV (4)[Rule 1303(a)(1)-BACT]</p> <p><b>PM10:</b> 0.01 GRAIN/DSCF (5A) [Rule 475]; <b>PM10:</b> 0.1 GRAIN/DSCF (5) [Rule 409]; <b>PM10:</b> 11 LB/HR (5B) [Rule 475]</p> <p><b>SOX:</b> <del>460</del> <u>0.06</u> LB/MMCF (8) [40 CFR60 Subpart GG KKKK];</p> <p><b>SO2:</b> (9) Acid Rain Provisions</p>	A63.1, <del>A63.2</del> -A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, I296.1, K40.1, K67.1

NOTE: Changes to the PDOC issued October 31, 2006 are denoted by underlined additions and ~~strikethrough~~ deletions

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 2
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**EQUIPMENT DESCRIPTION (continued)**

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
<b>Process 1: INTERNAL COMBUSTION</b>					
<b>System 1: GAS TURBINES, POWER GENERATION</b>					
CO OXIDATION CATALYST NO. 1, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450899	C3	D1 C4			
SELECTIVE CATALYTIC REDUCTION NO. 1, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; DEPTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450899	C4	S6 C3		NH3: 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 1, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450894	S6	C4			
GAS TURBINE, UNIT NO. 2, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F WITH WATER INJECTION, WITH A/N 450895  GENERATOR, 104 MW	D7	C9	NOX: MAJOR SOURCE	CO: 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; CO: 2000 PPMV (5) [Rule 407]  NOX: <del>440</del> <u>15</u> PPMV NATURAL GAS (8) [40CFR60 Subpart GG KKKK]; NOX: 123.46 LB/MMCF (1) [Rule 2012] NOX <del>40.86</del> <u>10.29</u> LB/MMCF NATURAL GAS (1)[Rule 2012] NOX 2.5 PPMV NATURAL GAS (4) [Rule 2005-BACT]  VOC: 2.0 PPMV (4)[Rule 1303(a)(1)-BACT]  PM10: 0.01 GRAIN/DSCF (5A) [Rule 475]; PM10: 0.1 GRAIN/DSCF (5) [Rule 409]; PM10: 11 LB/HR (5B) [Rule 475]  SOX: <del>150</del> <u>0.06</u> LB/MMCF (8) [40 CFR60 Subpart GG KKKK];  SO2: (9) Acid Rain Provisions	A63.1, A63-2 A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, I296.1, K40.1, K67.1

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 6
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

*Equipment Description (Continued)*

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
<b>Process 1: INTERNAL COMBUSTION</b>					
<b>System 1: GAS TURBINES, POWER GENERATION</b>					
CO OXIDATION CATALYST NO. 5, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450907	C27	D25 C28			
SELECTIVE CATALYTIC REDUCTION NO. 5, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; DEPTH: 1 FT 8 IN; WITH  NH3 INJECTION GRID A/N: 450907	C28	S30 C27		NH3: 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 5, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT  A/N: 450898	S30	C28			
<b>System 2: EMERGENCY FIRE PUMP</b>					
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE, DIESEL FUEL, LEAN BURN, CLARKE, MODEL JW6H-UF50, 340 BHP WITH  AFTERCOOLER, TURBOCHARGER, A/N: 450908	D34		NOX: PROCESS UNIT	<b>NOX+NMHC: 4.8 4.65</b> GM/BHP-HR DIESEL (4) [RULE 1303; RULE 2005]; <b>NOX: 469</b> LB/1000 GAL DIESEL (1) [RULE 2012]  <b>CO: 0.45</b> GM/BHP-HR DIESEL (4) [RULE 1303]  <b>PM10: 0.09</b> GM/BHP-HR DIESEL (4) [RULE 1303]  <b>SOX: 0.0055</b> GM/BHP-HR DIESEL (4) [RULE 1303];	C1.3, B61.1, D12.5, D12.6, E193.1, E193.2, I296.2, K67.2
<b>Process 2: INORGANIC CHEMICAL STORAGE</b>					
STORAGE TANK, TK-1, FIXED ROOF, 19 PERCENT AQUEOUS AMMONIA, DIAMETER: 12'-0"; HEIGHT: 12'-0"; 16,000 GALLONS WITH PRV SET AT 25 PSIG  WITH A/N: 451185	D31				C157.1, E144.1, E193.1

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 7
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

*Section D of the Facility Permit*

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
<b>Process 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE SPECIFIC RULES</b>					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, PORTABLE, ARCHITECTURAL COATING	E32			VOC: (9) [Rule 1113], Rule 1171	K67.3
RULE 219 EXEMPT EQUIPMENT, EXEMPT HAND WIPING OPERATIONS	E33			VOC: (9) [Rule 1171]	

**BACKGROUND**

In order to pursue the development of a proposed natural gas fired peaker project, Edison Mission Energy (EME) has organized a special purpose entity known as Walnut Creek Energy, LLC a Delaware limited liability company, to develop, own and operate the proposed peaker project. Walnut Creek Energy, LLC is a wholly-owned subsidiary of EME.

Walnut Creek Energy, LLC is proposing to construct a new power plant which will consist of five (5) combustion-turbine-generators (CTGs) for a total rated peak generating capacity of 520 MW at 45°F. The gas turbines will be General Electric LMS100 units. Each turbine will drive a generator rated at 104 MW at 45°F. The project is expected to have an annual capacity factor of approximately 20 to 40 percent, depending on weather-related customer demand, load growth, hydroelectric supplies, generating unit retirements, and other factors.

Each of the proposed CTGs will be configured in simple cycle, and therefore there will be no heat recovery steam generators (HRSG), duct burners, or steam turbines used at this plant. The net power generated (after taking away auxiliary power consumption) will be derived solely from the five generators. Selective catalytic reduction (SCR) systems and CO oxidation catalysts will be utilized for control of NOx and CO emissions, respectively. One 16,000 gallon ammonia (NH<sub>3</sub>) storage tank will be constructed for the storage of 19% aqueous ammonia which is part of the SCR process. A 5-cell mechanical drift cooling tower will provide heat removal for the gas turbine auxiliary cooling requirements. The site will also employ a 340 bhp diesel emergency fire pump engine.

The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger, including any related facilities such as transmission lines, fuel supply lines, and water pipelines. The CEC's 12-month, one-stop permitting process is a certified regulatory program under the California Environmental Quality Act (CEQA) and also includes several opportunities for public and inter-agency participation. The CEC's certification process subsumes all requirements of state, local, or regional agencies otherwise required before a new plant is constructed.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 8
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

The CEC coordinates its review of the facility with the federal agencies that will be issuing permits to ensure that the CEC certification incorporates conditions of certification that would be required by various federal agencies. Since the Walnut Creek Energy Project (WCEP) will be rated at greater than 50 megawatts, it is subject to the CEC's 12-month certification process. As part of this process, WCEP submitted an application for certification (05-AFC-2) to the CEC on November 22, 2005 seeking certification for the new power plant. In addition to the CEC certification process, WCEP submitted applications to AQMD seeking Permits to Construct for the new power plant. The following table shows the corresponding application numbers (A/Ns):

Table 1 - Applications for Permits to Construct Submitted to AQMD

Application Number	Equipment Description
450894	Gas Turbine No. 1
450895	Gas Turbine No. 2
450896	Gas Turbine No. 3
450897	Gas Turbine No. 4
450898	Gas Turbine No. 5
450899	SCR/CO Catalyst for Turbine No. 1
450900	SCR/CO Catalyst for Turbine No. 2
450901	SCR/CO Catalyst for Turbine No. 3
450904	SCR/CO Catalyst for Turbine No. 4
450907	SCR/CO Catalyst for Turbine No. 5
450908	Emergency Fire Pump Engine
451185	Aqueous Ammonia Storage Tank
450854	Initial Title V Application

Each of the applications were submitted to the AQMD on November 30, 2005, except for the application for the NH<sub>3</sub> storage tank, which was submitted on December 7, 2005. AQMD deemed the applications complete on December 13, 2005. Because WCEP will have the potential to generate electricity greater than 25 MW, it will be subject to the federal Acid Rain requirements and therefore the federal Title V permitting requirements apply. WCEP will also be included in the NO<sub>x</sub> RECLAIM program.

The Preliminary Determination of Compliance (PDOC) was issued on October 31, 2006. The Public Notice was published in the Los Angeles Daily News, the San Gabriel Valley Tribune, and the Spanish newspaper La Opinión. The notice was published in all three newspapers on November 15, 2006. The original Public Notice, engineering analysis and draft permit were submitted to the applicant on November 15, 2006, with copies being forwarded to the CEC, EPA, ARB, Federal Land Manger, State Land Manager, SCAG, and the Manager of the City of Industry. The applicant distributed copies of the Public Notice to each address within a ¼ mile radius of the project on December 19, 2006, and provided proof of such distribution in a January 4, 2007 letter from EME to AQMD (see file) which described the method of determining the addresses within the ¼ mile radius and the proof of such mailing in the form of the USPS certification.

AQMD received a total of four (4) comment letters during the 30-day Public Notice period, one in which the applicant provided their comments to the draft analysis and permit. SCAG provided a letter in which they indicated that the proposed project did not warrant comments at this time. The two remaining comment letters were from Perrin Manufacturing Company and Hydrogen Ventures, Inc. These comments are



<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 9
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

addressed in detail in the comments and responses section of this analysis. EPA provided questions on the proposed Title V permit via e-mail in regards to the PM10 modeling under NSR rules, however, EPA elected not to make any formal comments regarding this issue.

### Processing Fee Summary

On November 30, 2005, AQMD received the thirteen (13) applications shown in the table above along with a total processing fee of \$62,165.76. ~~The \$62,165.76 processing fee covers the processing fees for both the WCEP and another proposed power plant (Sun Valley Energy Project, aka SVEP) to be located in Romoland, CA.~~ However, the correct schedule for the basic equipment is Schedule G, which is shown in the table below. The applicant also included a signed form 400-XPP and the appropriate fees for expedited permit processing. The five LMS100s are identical and therefore, four of these devices receive a 50% discount off of the original processing fee of ~~\$3,364.77~~ \$9,459.62. In addition, the five SCR/CO catalysts are identical and therefore, four of these devices receive a 50% discount off of the original processing fee of \$2,437.95. The normal processing fees are multiplied by 1.5 for expedited processing. A fee summary for WCEP is shown in the table below. WCEP was advised of the fee discrepancy via email dated February 6, 2007 and has committed to correct this discrepancy by submitting the additional payments.

Table 2 - Summary of Processing Fees for WCEP

A/N	Equipment	Schedule	Processing Fee	XPP	TOTAL
450894	LMS100 Gas Turbine No. 1	D G	<del>\$3,364.77</del> <u>\$9,459.62</u>	1.5	<del>\$5,047.16</del> <u>\$14,189.43</u>
450895	LMS100 Gas Turbine No. 2	D G	<del>\$1,682.39</del> <u>\$4,729.81</u>	1.5	<del>\$2,523.59</del> <u>\$7,094.72</u>
450896	LMS100 Gas Turbine No. 3	D G	<del>\$1,682.39</del> <u>\$4,729.81</u>	1.5	<del>\$2,523.59</del> <u>\$7,094.72</u>
450897	LMS100 Gas Turbine No. 4	D G	<del>\$1,682.39</del> <u>\$4,729.81</u>	1.5	<del>\$2,523.59</del> <u>\$7,094.72</u>
450898	LMS100 Gas Turbine No. 5	D G	<del>\$1,682.39</del> <u>\$4,729.81</u>	1.5	<del>\$2,523.59</del> <u>\$7,094.72</u>
450899	SCR/CO Catalyst No. 1	C	\$2,437.95	1.5	<del>\$3,656.93</del> <u>\$3,656.93</u>
450900	SCR/CO Catalyst No. 2	C	\$1,218.98	1.5	\$1,828.47
450901	SCR/CO Catalyst No. 3	C	\$1,218.98	1.5	\$1,828.47
450904	SCR/CO Catalyst No. 4	C	\$1,218.98	1.5	\$1,828.47
450907	SCR/CO Catalyst No. 5	C	\$1,218.98	1.5	\$1,828.47
450908	Emergency Fire Pump	B	\$1,541.34	1.5	\$2,312.01
451185	Ammonia Storage Tank	A	\$967.11	1.5	\$1,450.67
450854	Title V Application	N/A	\$1,007.60	N/A	\$1,007.60
<b>WCEP TOTAL PROCESSING FEE</b>					<del>\$31,082.61</del> <u>\$58,309.40</u>

### Site Description

The proposed location of WCEP is on an 11.48 acre parcel currently owned by the Industry Urban Development Agency (Development Agency). The parcel is located at 911 Bixby Drive, City of Industry, CA 91744. The parcel is entirely covered with a large warehouse building and asphalt paving and is currently in use as a commercial distribution facility. The Development Agency has planned this parcel for redevelopment and plans to demolish the existing structure in the near future. EME has entered into a lease option agreement for the project site. The lease option will be assigned to and exercised by Walnut Creek Energy, LLC who will take physical possession of the site from the Development Agency after the demolition has taken place. The City of Industry is in the process of reviewing a Negative Declaration for the demolition in order to make the parcel available for a higher-value industrial use. WCEP will be located in an area zoned for industrial uses.

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 10
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

The project site is located within the boundaries of the La Puente Mexican land grant rancho and does not have township, range, and section designations. The Los Angeles County Assessor's parcel designation is 8242-013-901.

**COMPLIANCE RECORD**

WCEP is a new facility and construction on the proposed power plant has not yet begun. No additional existing sources are presently operating under the above facility ID. As a confirmation, the AQMD's Compliance Tracking System database indicates no compliance activity for this facility ID.

**PROCESS DESCRIPTION**

The proposed power plant will operate in simple cycle configuration and will employ five (5) General Electric LMS100 combustion gas turbines, each of which employ off-engine intercooling technology with the use of water and an external heat exchanger for increased thermal efficiency. The LMS100 system includes a 3-spool gas turbine configured with an intercooler located between the low-pressure compressor (LPC) and the high-pressure compressor (HPC).

**Intercooling**

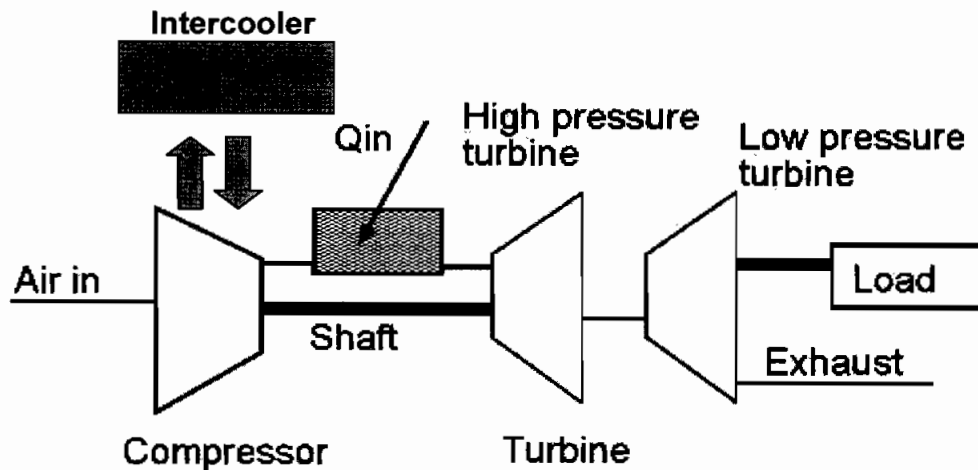
Intercooling provides significant benefits to the Brayton cycle by reducing the work of compression for the HPC, which allows for higher pressure ratios and thereby increasing overall efficiency. For the LMS100, the cycle pressure ratio is 42:1. The reduced inlet temperature for the HPC allows increased mass flow resulting in higher specific power. The lower resultant compressor discharge temperature provides colder cooling air to the turbines, which in turn allows increased firing temperatures equivalent to those of the LM6000, producing an overall cycle efficiency in excess of 46% in simple cycle configuration. This represents a 10% increase in the efficiency over the LM6000. The LMS100 can be configured with two different types of intercooling systems, with the first type being a wet intercooling system which uses an air-to-water heat exchanger (shell and tube design) and an evaporative cooling tower. The second system consisting of bellows expansion joints, moisture separator, variable bleed valve system, and associated piping and involves a dry intercooling system requiring no water. It uses an air-to-air heat exchanger constructed with panels of finned tubes mounted in an A-frame configuration. All five LMS100s proposed for construction at WCEP will be configured with a wet intercooling system. A general diagram of the LMS100 employing wet intercooling technology to be used at the WCEP is shown in the diagram below.

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SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT  ENGINEERING AND COMPLIANCE DIVISION  ENGINEERING ANALYSIS / EVALUATION	PAGES 64	PAGE 11
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

### LMS100 Gas Turbine with Intercooler



WCEP will connect to Southern California Edison's (SCE) electrical transmission system at the Walnut Substation, which is located approximately 250 feet south of the proposed project site. This connection will require 600 feet of 230-kilovolt (kV) transmission line and two transmission towers to be located adjacent to the substation within SCE's transmission corridor. Interconnection at this specific substation minimizes downstream impacts to SCE's transmission system while providing efficient peaking power for use during peak demand as projected by SCE. Reclaimed water for the cooling tower and evaporative cooler make-up, site landscape irrigation, and demineralized water make-up will be supplied via a direct connection to a 12 inch diameter reclaimed water pipeline at the corner of Bixby Drive and Chestnut Street, adjacent to the project entrance, through a 12 inch diameter pipe extending approximately 30 feet from the project boundary into Bixby Drive. The Rowland Water District will supply on the average, approximately 827 acre-feet per year of reclaimed water from the San Jose Creek Wastewater Reclamation Plant. The following table lists the technical specifications for the General Electric LMS100 CTG.

The site plan shown on the previous page 13 was prepared for WCEP by CH2MHILL and shows the general layout of the proposed facility. The project site is located in an industrial area and is surrounded to the south, east, and west by warehousing and other industrial uses. To the north is an SCE utility corridor used for transmission lines. Beyond the corridor is the San Jose Flood Control Channel, and beyond that to the north, an intermodal rail/truck terminal.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 12
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

Residential areas are located in the City of La Puente to the north, beyond the industrial areas that are adjacent to the project site, and in unincorporated areas of the Los Angeles County community of Hacienda Heights to the south.

**Table 3 - Combustion Turbine Generator Specifications<sup>1</sup>**

Parameter	Specifications
Manufacturer	General Electric
Model	LMS100PA <sup>2</sup>
Fuel Type	PUC <sup>3</sup> Quality Natural Gas
Natural Gas Heating Value	1,050 BTU/scf
Gas Turbine Heat Input (HHV)	904 MMBTU/hr at 45°F and 60% relative humidity
Fuel Consumption	0.861 MMSCF/hr <sup>4</sup>
Gas Turbine Exhaust Flow	364,419 DSCFM
Gas Turbine Exhaust Temperature	762°F
Exhaust Moisture	6-8%
Gas Turbine Power Generation	104 MW
Net Plant Heat Rate, LHV	8,061 BTU/kW-hr

<sup>1</sup> Values in this table are on a per-turbine basis

<sup>2</sup> GE Manufactures two versions of the LMS100 CTG. WCEP plans to install the LMS100PA. The PA model utilizes water injection for NOx abatement while the PB version utilizes dry low emission (DLE) combustors for NOx abatement.

<sup>3</sup> PUC is the acronym for the California Public Utilities Commission

<sup>4</sup> Represents the maximum possible fuel consumption of the CTG, based on 904 MMBTU/hr heat input and 1,050 BTU/scf fuel heat content. However, the emission calculations will be based on a worst-case operating scenario as identified by the applicant, which may result in a lower fuel usage depending on the ambient temperature, the employment and rate of intercooling, water injection rates, and electrical load generated.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

ENGINEERING AND COMPLIANCE DIVISION

ENGINEERING ANALYSIS / EVALUATION

PAGES  
64

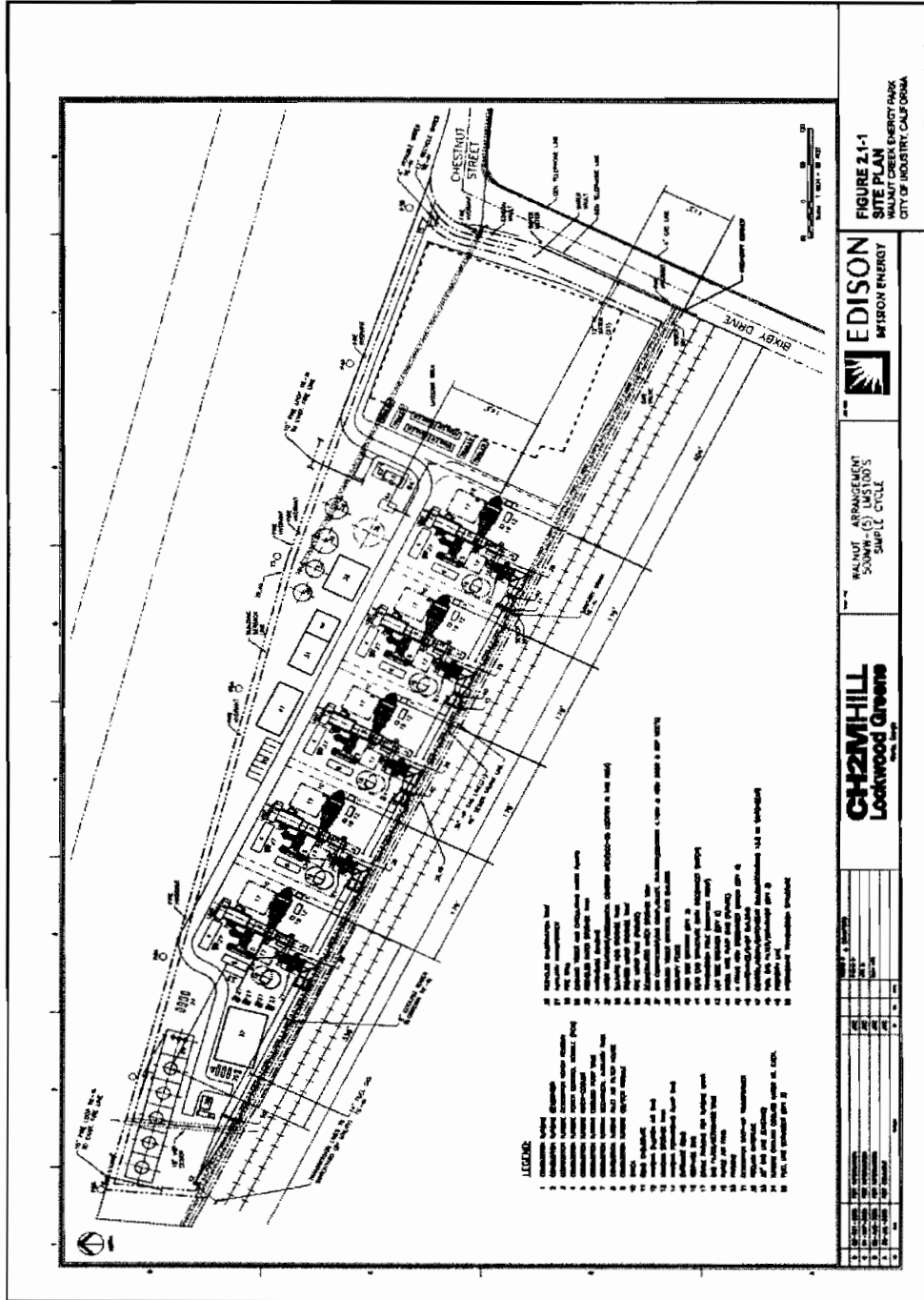
PAGE  
13

APPLICATION NO.  
450894 (Master File)

DATE  
2-14-2007

PROCESSED BY:  
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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 14
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**Definition of a Peaking Unit in Rule 2012**

A traditional peaking unit is defined as a turbine which is used intermittently to produce energy on a demand basis and does not operate more than 1,300 hours per year. This definition is found in *Rule 2012-Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NOx) Emissions, Attachment A-F* as amended December 5, 2003. WCEP will have the potential to operate for about 3,468 hours/year inclusive of start-up, shutdown, commissioning, maintenance, (if any) and normal operations. Since the annual hours of operation will exceed that which is allowed for a traditional peaking unit under Rule 2012, the LMS100s will not be classified as official peaking units in the equipment descriptions. The CTGs will be listed as a NOx Major Source under Rule 2012.

**Air Pollution Control (APC) System**

All five CTGs will utilize two primary means for the reduction of NOx emissions. On the front end, WCEP will rely on the use of demineralized water for water injection directly into the CTGs. The demineralized water will be produced by reverse osmosis (RO) and an ion exchange system and will be stored in a 100,000 gallon demineralized water storage tank. The use of demineralized water injection will reduce the 1-hour average NOx concentration to 25 ppmv on a dry basis at 15% O<sub>2</sub> prior to entry to the selective catalytic reduction (SCR) units. On the back end, and SCR catalyst with ammonia injection will be used downstream of each CTG for further reduction of NOx emissions and a CO oxidation catalyst will be used downstream of each CTG for CO emissions reduction. As a result, the NOx emissions will be limited to 2.5 ppmv, 1-hour average, dry basis at 15% O<sub>2</sub>. CO emissions will be limited to 6.0 ppmv, 1-hour average, dry basis, at 15% O<sub>2</sub>. ROG emissions will be limited to 2.0 ppmv, dry basis at 15% O<sub>2</sub>. SOx and PM<sub>10</sub> emissions will be mitigated through the use of PUC quality natural gas. Detailed descriptions of the air pollution control system are given in the next section. The CO catalyst is permitted together with the SCR catalyst.

**Selective Catalytic Reduction/CO Catalyst Systems (A/Ns 450899, 450900, 450901, 450904, & 450907)**

Table 4 below shows the specifications for the SCR manufacturer to be used for the simple cycle CTGs.

Table 4 - Selective Catalytic Reduction

Catalyst Properties	Specifications
Manufacturer	Haldor-Topsoe
Catalyst Description	Ti V honeycomb single layer structure
Catalyst Model No.	DNX 920
Catalyst Volume	850 ft <sup>3</sup>
Guaranteed Life	Earliest of 20,000 hrs from first gas-in or 51 months from contracted delivery.
Space Velocity	23,580 hr <sup>-1</sup>
Ammonia Injection Rate	190 lb/hr
NOx removal efficiency	>90%
NOx at stack outlet	2.5 ppmv at 15% O <sub>2</sub>
Exhaust Temperature	740-800°F

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 15
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

The SCR catalyst will use ammonia injection in the presence of the catalyst to reduce NOx. Diluted ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NOx to elemental nitrogen (N<sub>2</sub>) and water, resulting in NOx concentrations in the exhaust gas at no greater than 2.5 ppmvd at 15% O<sub>2</sub> on a 1-hour average.

### **CO Oxidation Catalyst**

The CO oxidation catalyst will be installed within the catalyst housing which will reduce CO in the exhaust gas to no greater than 6 ppmvd at 15% O<sub>2</sub>, on a 1-hour average. The exhaust from each catalyst housing will be discharged from individual 90-foot tall, 13.5 foot diameter exhaust stacks. Each CTG will have its own individual stack.

WCEP has indicated that the CO catalyst manufacturer is to be Englehard. The following table lists the specifications for the CO catalyst. The operating temperature window is between 500°F and 1,250°F.

Table 5 - CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	Englehard
Model	Camet
Catalyst Type	Pt on Al single layer metal monolith
Catalyst Life	20,000 hours or 5 years
Space Velocity	125,000 hr <sup>-1</sup>
Volume	200 ft <sup>3</sup>
CO removal efficiency	90%
CO at stack outlet	6.0 ppmvd at 15% O <sub>2</sub>
Exhaust gas velocity	24 ft/s

### **Aqueous Ammonia Storage Tank (A/N 451185)**

The ammonia will be transported to the site in aqueous form and will have a maximum concentration of 19% by weight. The ammonia will be stored in a specially designated tank with a capacity of 16,000 U.S. gallons with a maximum design pressure of 25 psig, and will be constructed to ASME Section VIII specifications. A vapor return line will be used during receiving operations to control filling losses.

### **Heated Ammonia Vaporization Skid**

The ammonia vaporization skids will be used to vaporize the 19% aqueous ammonia so that it can be transferred to the ammonia injection grids. The ammonia vaporization equipment will be shop-assembled and skid mounted for easy field installation. During cold start-up of the turbine, it will take some time (~10 minutes) before the ammonia injection chamber is hot enough to heat the ammonia for injection. Therefore, each ammonia injection chamber is equipped with an electric pre-heater unit which can be initiated prior to the cold start-ups to ensure that the ammonia is adequately heated prior to injection. The ammonia vaporization skids are typically configured with two dilution air fans (one operating and one spare) and two pre-heater elements (one operating and one spare) housed in a common heater box. In addition, the aqueous ammonia is typically atomized in the ammonia injection chamber and is then fed to the ammonia distribution header.

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 16
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

### **Ammonia Distribution Header**

A carbon steel ammonia distribution header will be used to receive the hot ammonia/air mixture from the ammonia vaporization skid and deliver it evenly to the ammonia injection grid piping. Typically, the injection grid supply piping is equipped with manual butterfly valves and flow instrumentation used for adequate balancing of ammonia flow.

### **Performance Warranties**

Performance warranties for the CO/oxidation and SCR catalysts have been included with the application package and are part of the engineering file. According to the performance warranty<sup>5</sup> for the CO/oxidation catalyst, it will be able to achieve approximately 90% CO reduction from inlet levels of CO. The SCR catalyst will be able to achieve approximately 90% reduction efficiency from inlet levels of NOx and the maximum ammonia slip is warranted to not exceed 5.0 ppmvd at 15% O<sub>2</sub>. The table below shows the warranted emissions for NOx, CO, VOC and NH<sub>3</sub> slip.

Table 6 - Warranted Emissions for APC System

Pollutant	Warranted Emissions
Outlet NOx emissions	2.5 ppmv at 15% O <sub>2</sub> , dry basis
Outlet CO emissions	6.0 ppmv at 15% O <sub>2</sub> , dry basis
Outlet VOC emissions	2.0 ppmv at 15% O <sub>2</sub> , dry basis
Ammonia Slip	5.0 ppmv at 15% O <sub>2</sub> , dry basis

### **Cooling Tower System**

A 5-cell cooling tower will be included in the proposed design to provide for the gas turbine auxiliary cooling requirements. Two 50% capacity circulating water pumps will provide water to cool three closed-cooling water heat exchangers. The circulating water rate will be 35,500 gallons per minute (GPM). The heat exchangers are each rated at 33% capacity. The closed-cooling water heat exchangers will provide high-quality cooling water to a GE provided pump skid for each CTG. The pump skid will then provide cooling water to the CT compressor intercooler and to the lubrication system. Drift is water entrained by and carried with the air as unevaporated fine droplets. PM<sub>10</sub> matter is released from a cooling tower through drift. Any solids that are dissolved in the cooling water will be carried out of the tower with the water droplets that are entrained in the air. The water droplet will ultimately evaporate and leave the dissolved solid as PM<sub>10</sub>. The rate of PM<sub>10</sub> that is discharged to the atmosphere depends significantly on the drift factor for the cooling tower. The drift factor is the percentage of coolant that leaves through drift with respect to the total flow rate of coolant through the tower. Typical drift rates based on the age of the cooling tower are shown in Table 7 below.

<sup>5</sup> The performance warranty does not explicitly state an expected conversion efficiency for VOC. However, based on experience with similar turbines, it is expected that at least a 50% reduction efficiency for VOC can result such that VOC emissions at the catalyst outlet can be expected to meet 2.0 ppmvd @ 15% O<sub>2</sub>. Therefore, uncontrolled VOC emissions are assumed to be 4.0 ppmvd at 15% O<sub>2</sub>, dry basis.



<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 17
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**Table 7 - Typical Drift Rates Based on the Age of the Cooling Tower**

Year of Construction	Drift Rate as a Percentage of Circulating Water Flow Rate
1970s	0.01%
Early 1980's	0.008%
Mid 1980's	0.005%
1990's	0.002%
2000	0.001%
Current Technology	0.0005%

In keeping with current technology, maximum drift loss will be limited to 0.0005% of the circulating water flow. The following table lists the specifications for the cooling tower.

**Table 8 - Cooling Tower Specifications**

Cooling Tower Parameters	Specifications
Manufacturer	Marley
Number of Cells	5
Exhaust Fan Diameter (ft)	22
Exhaust Flow per Cell (ACFM)	860,100
Circulating Water Rate (GPM)	35,500
Circulating Water Rate (MMLb/hr)	17.74
Fan Exit Height (ft AGL)	39.09

**Emergency Fire Pump Engine (A/N 450908)**

The fire pump engine will be a diesel fueled Clarke unit, model no. JW6H-UF50. It has a power rating of 340 bhp at 2,100 rpm. The specifications are listed in the table below.

**Table 9 - Emergency Fire Pump Specifications**

Emergency Fire Pump Parameters	Specifications
Manufacturer	Clarke
Power output	340 bhp at 2,100 rpm
Fuel Consumption	16.0 gal/hr
Exhaust temperature	744°F
Exhaust flow	2,066 ACFM
Stack height	40 ft
Stack diameter	5 in

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 18
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**CRITERIA POLLUTANT EMISSIONS**

The total emissions from the power plant will include the summation of all five CTGs, the emergency fire pump engine, and the PM<sub>10</sub> emissions from the cooling tower. The emissions from the gas turbines are based on the following formula and assumptions:

$$EF(\text{lb/MMBTU}) = \text{ppmvd} \times \text{MW} \times \left( \frac{1}{\text{SMV}} \right) \left( \frac{20.9}{5.9} \right) \times F_d$$

where,

- ppmvd = Uncontrolled (or controlled) concentration at 15% O<sub>2</sub>, dry basis
- MW = Molecular weight, lb/lb-mol
- SMV = Specific molar volume at 68°F = 385.3 dscf/lb-mol
- F<sub>d</sub> = Dry oxygen f-factor for natural gas at 68°F = 8,710 dscf/MMBTU

**Assumptions:**

1. Emissions are based on the worst case operating scenario
2. PM<sub>10</sub> emissions are based on 0.0067 lb/MMBTU
3. SO<sub>2</sub> to SO<sub>3</sub> conversion in APC equipment is accounted for in the PM<sub>10</sub> AP-42 emission factor
4. SO<sub>x</sub> emissions are based on 0.25 grains/100 scf
5. 30-Day Averages are based on 463 hours/month of operation
6. Emissions are based on total fuel consumption rather than total hours of operation

The applicant has identified fifteen possible operating scenarios. The fifteen scenarios are listed as operating conditions (OC) 100 through 114 in Section 5 of the applicant's submittal and are summarized in the table below:

**Table 10 - Operating Scenarios**

	Ambient Temp °F	H <sub>2</sub> O Injection, lb/hr	Relative Humidity (%)	Intercooler (on/off)	Compressor Inlet Temp °F
OC100	30	35,385 (100%)	60	On	30
OC101	30	24,795 (70%)	60	On	30
OC102	30	15,760 (45%)	60	On	30
OC103	59	32,449 (92%)	60	On	53
OC104	59	22,235 (63%)	60	On	53
OC105	59	13,945 (39%)	60	On	53
OC106	84	28,325 (80%)	53	On	73
OC107	84	18,872 (53%)	53	On	73
OC108	84	11,031 (31%)	53	On	73
OC109	90	28,389 (80%)	37	On	73
OC110	90	18,917 (53%)	37	On	73
OC111	90	11,074 (31%)	37	On	73
OC112	110	28,408 (80%)	10	On	74
OC113	110	18,932 (54%)	10	On	74
OC114	110	11,527 (33%)	10	On	74

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 19
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

### Detail of Operating Conditions

Analysis of the applicant's operating scenarios reveals that GE ran the tests while varying the water injection rate, and compressor inlet temperature. Ambient temperature was allowed to vary from a minimum of 30°F to a maximum of 110°F. Note from the table above that for each ambient temperature, the load was varied between maximum (100%), average (75%), and minimum (50%) loads. The top five cases where fuel flow to the CTGs is the greatest (and therefore yielding the highest emissions) are shown in the table below.

Table 11 - Worst Case Operating Scenario

	Top 5 Operating Conditions				
	100	103	106	109	112
Ambient Temperature, °F	30	59	84	90	110
Ambient Pressure, psia	13.937	13.937	13.937	13.937	13.937
Fuel Consumption, MMBTU/hr	803.3	791.6	748.4	749.5	749.6
Fuel Consumption, lb/hr	38,941	38,373	36,277	36,330	36,337
Exhaust Temperature, °F	761.1	781.6	796.6	796.2	796.1
Load, MW	103.8	101.3	94.2	94.4	94.4
Water Injection (on/off)	On	On	On	On	On
Water Injection, lb/hr	35,385	32,449	28,325	28,389	28,408
Intercooler (on/off)	On	On	On	On	On

Of the top five cases, the worst case scenario occurs during periods of *maximum* fuel consumption (803.3 MMBTU/hr) at full load (103.8 MW), low ambient temperature (30°F), with water injection in full use, and the intercooler in operation, as identified in the table above by operating condition no. 100. Therefore, to address the worst case scenario, the facility's NSR emissions will be based on the parameters listed in operating condition no. 100.

There are essentially four modes of operation for the CTGs. Emissions from the four operating modes are distinctly different and must be calculated independently. The following table gives more detail of the four operating modes.

Table 12 - Operating Modes of the CTGs

Mode	Description
Commissioning	The process of fine-tuning each of the CTGs. Facility follows a systematic approach to optimize performance of each of the CTGs and the associated control equipment. Emissions are expected to be greater during commissioning than during normal operation. This mode affects only the initial year of operation.
Start-up	The applicant has indicated that there will be up to two start-ups per day for each CTG, with each start-up lasting 35 minutes. Start up emissions are higher due to the fact that the control equipment has not reached optimal temperature to begin the chemical reactions needed to convert NOx to elemental nitrogen and water.
Normal Operation	Normal operation occurs after the CTGs and the control equipment are working optimally, at their designated levels, i.e. NOx emissions are controlled to 2.5 ppmvd at 15% O <sub>2</sub> , CO emissions to 6.0 ppmv at 15% O <sub>2</sub> , and VOC to 2.0 ppmvd at 15% O <sub>2</sub> . Emissions may vary due to ambient conditions.
Shutdown	Shutdown occurs at the initiation of the turbine shutdown sequence and ends with the cessation of CTG firing, and will last approximately 11 minutes thereafter. Typically, the shutdown process will emit less than the start-up process but may emit slightly greater than during normal operation because both H <sub>2</sub> O injection into the CTGs and NH <sub>3</sub> injection into the SCR reactor have ceased operation

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 20
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

### Commissioning Period

Gas turbine commissioning consists of zero load, partial load and full load testing performed immediately after construction for the purposes of optimizing turbomachinery, gas turbine combustors, and optimizing and testing of the SCR/CO catalysts. Several parameters such as water injection rate and degree of SCR and CO control may be varied simultaneously during testing at the discretion of the applicant. Emissions during the commissioning year (usually the first year of operation) may be higher than those during a non-commissioning year due to the fact that the combustors may not be optimally tuned and the SCR/CO catalysts may be only partially operational or not operational at all. The applicant has allocated up to 134 hours of commissioning for each of the 5 CTGs and has further stated that all commissioning will be accomplished within the 9 months prior to initial operation. The commissioning schedule will comprise 6 phases in which the CTGs will be operated at zero, minimum, average and maximum loads while varying the water injection rates and the degree of SCR reactor and CO catalyst control. There will be some cases where the 5 CTGs will be run simultaneously during the commissioning period, and some cases where only one unit may be tested at a time. It will be assumed that the commissioning of the units will be simultaneous to address the worst case scenario. The table below shows the applicant's proposed commissioning schedule along with the cumulative emissions for each of the 5 CTGs during the commissioning period.

Table 13 - Proposed Commissioning Schedule

Commissioning Phase	1	2	3	4	5	6	Totals
Water Injection (% operation)	0	0	50%	100%	100%	100%	
SCR Reactor (% operation)	0	0	0	0	50%	100%	
CO Catalyst (% operation)	0	0	0	0	100%	100%	
Hours per phase	20	14	24	12	24	40	134
Average Load (%)	0%	5%	50%	100%	75%	100%	
NOx (lb/hr)	91	99	175	81	35	8.1	
CO (lb/hr)	55	60	168	255	9	12	
VOC (lb/hr)	2	2	3	5	4	2	
PM <sub>10</sub> (lb/hr)	1	1	3	6	5	6	
SOx (lb/hr)	0.051	0.061	0.170	0.306	0.238	0.306	
HHV (MMBTU/hr)	150	180	500	900.5	700	900.5	
NOx (lb/mm scf)	641	581	370	95	53	9	
CO (lb/mm scf)	387	352	355	299	14	14	
VOC (lb/mm scf)	14	12	6	6	6	2	
PM <sub>10</sub> (lb/MMBTU)	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	
SOx (lb/MMBTU)	0.00068	0.00068	0.00068	0.00068	0.00068	0.00068	
Total NOx lbs, (5 units)	9,100	6,930	21,000	4,860	4,200	1,620	47,710
Total CO lbs, (5 units)	5,500	4,200	20,160	15,300	1,080	2,400	48,640
Total VOC lbs, (5 units)	200	140	360	300	480	400	1,880
Total PM <sub>10</sub> lbs, (5 units)	100	70	360	360	600	1,200	2,690
Total SOx lbs, (5 units)	10.2	12.2	34.0	61.2	47.6	61.2	226.4

### Start-up / Shutdown of CTGs

The applicant has stated that there will be 350 start-ups and 350 shutdowns per year, with up to 2 start ups per day, with the balance of 2,768 hours left for commissioning and normal operations. According to the applicant, each start-up event is expected to last 35 minutes. During start-up operations, the turbine is assumed to operate at elevated NOx and CO average concentration rates due to the phased-in

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 21
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

effectiveness of the SCR reactor and CO oxidation catalysts. Start-ups begin with each turbine's initial firing and continue until each unit complies with the permitted emission concentration limits.

NOx levels are in the 50-100 ppmvd range from the first 3-8 minutes of start-up. Water is injected during the 8<sup>th</sup> minute of start-up and 25 ppmvd at 15% O<sub>2</sub> is achieved by minute 10 when the unit reaches full load. NOx emissions are further reduced from 25 ppmvd to 2.5 ppmvd over a 30-60 minute period after the CTG achieves full load. CO emissions are assumed to be in the 100-500 ppmvd range for minutes 3 through 10 of start-up. At full load (minute 10), the CO emissions are approximately 100 ppmvd. CO emissions are further reduced from 100 ppmvd to 6 ppmvd over a 30-60 minute period after the CTG achieves full load. GE has provided start-up estimates for the five CTGs and these numbers are included in Appendix A. Shutdowns begin with the initiation of the turbine shutdown sequence and end with the cessation of turbine firing. According to the applicant, each shutdown will last eleven minutes. Upon initiation of the shutdown process, ammonia and water injection will be discontinued. Normal operating emission rates are assumed to occur during the preceding 48 minutes of the shutdown period. GE has provided shutdown estimates for the five CTGs and these numbers are included in Appendix A.

### **Normal Operations**

The emissions during normal operations are assumed to be fully controlled to Best Available Control Technology (BACT) levels, and exclude emissions due to commissioning, start up and shutdown periods, which are not subject to BACT levels. Hourly, monthly, and annual emissions as well as the 30-day averages are calculated and shown in Appendices A through C. The emission calculations for the emergency fire pump and cooling tower are contained in Appendices D and E.

### **Emissions During A Commissioning Year**

The tables below show the cumulative emissions during a commissioning year from all 5 gas turbines which includes commissioning, start-up, shutdown and normal operation, as well as the emissions from the emergency fire pump which is assumed to operate for the designated maximum of 199 hours per year, and the PM<sub>10</sub> emissions from the 5-cell cooling tower.

#### **Mass Emission Rates, lb/hr (Commissioning Year)**

LMS100PA CTG	Emissions, lb/hr					
	NOx	CO	VOC	SO <sub>2</sub>	PM <sub>10</sub>	NH <sub>3</sub>
Normal Operations	41.05	60.00	8.55	3.03	30.00	30.35
Start up	51.20	102.00	14.05	3.03	30.00	N/A
Shutdown	55.00	140.00	15.00	3.03	30.00	N/A
Commissioning	356.04	362.99	14.02	1.69	20.07	N/A
Emergency Fire Pump	10.54	<del>0.202</del> 0.337	0.112	0.0041	<del>0.059</del> 0.067	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	0.443	N/A
<b>TOTALS</b>	<b>514.73</b>	<b>665.1933</b>	<b>51.73</b>	<b>10.78</b>	<b>110.578</b>	<b>30.35</b>

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 22
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**Mass Emission Rates, lb/month (Commissioning Year)**

LMS100PA CTG	Emissions, lb/month					
	NOx	CO	VOC	SO <sub>2</sub>	PM <sub>10</sub>	NH <sub>3</sub>
Normal Operations	15,105.00	22,080.00	<del>3,146.40</del> 4,195.00	1115.00	11,040.00	11,168.80
Start up	2,084.00	4,080.00	562.00	120.00	1,200.00	N/A
Shutdown	2,200.00	5,600.00	600.00	120.00	1,200.00	N/A
Commissioning	5,340.00	5,445.00	210.75	25.50	300.00	N/A
Emergency Fire Pump	174.79	<del>3.35</del> 5.59	1.86	0.07	1.12	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	128.30	N/A
<b>TOTALS</b>	<b>24,903.79</b>	<b><del>37,208.35</del> 37,210.59</b>	<b><del>4,521.01</del> 5,568.00</b>	<b>1,383.07</b>	<b>13,869.42</b>	<b>11,168.80</b>

**Mass Emission Rates, lb/year (Commissioning Year)**

LMS100PA CTG	Emissions, lb/year					
	NOx	CO	VOC	SO <sub>2</sub>	PM <sub>10</sub>	NH <sub>3</sub>
Normal Operations	108,125.00	158,040.00	22,520.00	7,980.00	79,020.00	79,939.42
Start up	18,235.00	35,700.00	4,920.00	1,060.00	10,500.00	N/A
Shutdown	19,250.00	49,000.00	5,250.00	1,060.00	10,500.00	N/A
Commissioning	47,710.00	48,640.00	1,880.00	228.00	2,690.00	N/A
Emergency Fire Pump	2,097.46	<del>40.24</del> 67.06	22.35	0.82	13.41	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	1,539.60	N/A
<b>TOTALS</b>	<b>195,417.46</b>	<b><del>291,420.24</del> 291,447.06</b>	<b>34,592.35</b>	<b>10,327.82</b>	<b>104,263.01</b>	<b>79,939.42</b>

**Emissions During A Non-Commissioning Year**

The tables below show the cumulative emissions during a non-commissioning year from all 5 gas turbines which includes, start-up, shutdown and normal operation, as well as the emissions from the emergency fire pump which is assumed to operate for the designated maximum of 199 hours per year, and the PM<sub>10</sub> emissions from the 5-cell cooling tower.

**Mass Emission Rates, lb/hr (Non-Commissioning Year)**

LMS100PA CTG	Emissions, lb/hr					
	NOx	CO	VOC	SO <sub>2</sub>	PM <sub>10</sub>	NH <sub>3</sub>
Normal Operations	41.05	60.00	8.55	3.03	30.00	30.35
Start up	51.20	102.00	14.05	3.03	30.00	N/A
Shutdown	55.00	140.00	15.00	3.03	30.00	N/A
Emergency Fire Pump	10.54	<del>0.202</del> 0.337	0.112	0.0041	0.067	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	0.443	N/A
<b>TOTALS</b>	<b>158.69</b>	<b>302.2034</b>	<b>37.71</b>	<b>9.09</b>	<b>90.51</b>	<b>30.35</b>

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 23
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**Mass Emission Rates, lb/month (Non-Commissioning Year)**

LMS100PA CTG	Emissions, lb/month					
	NOx	CO	VOC	SO <sub>2</sub>	PM <sub>10</sub>	NH <sub>3</sub>
Normal Operations	15,720.00	22,980.00	<del>3,275.00</del> 4,365.00	1,161.49	11,490.00	11,625.29
Start up	2,084.00	4,080.00	562.00	121.20	1,200.00	N/A
Shutdown	2,200.00	5,600.00	600.00	121.20	1,200.00	N/A
Emergency Fire Pump	174.79	<del>3.35</del> 5.59	1.86	0.07	1.12	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	128.30	N/A
<b>TOTALS</b>	<b>20,178.79</b>	<del><b>32,663.35</b></del> <b>32,665.59</b>	<del><b>4,438.86</b></del> <b>5,528.00</b>	<b>1,403.96</b>	<b>14,019.42</b>	<b>11,625.29</b>

**Mass Emission Rates, lb/year (Non-Commissioning Year)**

LMS100PA CTG	Emissions, lb/year					
	NOx	CO	VOC	SO <sub>2</sub>	PM <sub>10</sub>	NH <sub>3</sub>
Normal Operations	113,626.40	166,080.00	23,666.40	8,387.00	83,040.00	83,945.03
Start up	18,235.00	35,700.00	4,920.00	1,060.00	10,500.00	N/A
Shutdown	19,250.00	49,000.00	5,250.00	1,060.00	10,500.00	N/A
Emergency Fire Pump	2,097.46	<del>40.24</del> 67.06	22.35	0.82	13.41	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	1,539.60	N/A
<b>TOTALS</b>	<b>153,208.86</b>	<del><b>250,820.24</b></del> <b>250,847.06</b>	<b>33,858.75</b>	<b>10,507.82</b>	<b>105,593.01</b>	<b>83,945.03</b>

**30-Day Averages**

The 30 Day Average emissions are calculated in Appendix B for both a commissioning and non-commissioning year for the worst case operating scenario. The worst case operating scenario was defined as OC100 in Table 10 above. The values in the tables below are the cumulative 30 day averages for the entire facility (5 CTGs, the emergency fire pump and the cooling tower).

**Cumulative 30-Day Averages, lb/day (Commissioning Year)**

Five LMS100PA CTGs	30 Day Average, lb/day				
	NOx <sup>6</sup>	CO	VOC	SOx	PM <sub>10</sub>
Normal Operations		736	<del>105</del> <u>140</u>	37	368
Start up		136	19	4	40
Shutdown		187	20	4	40
Commissioning		181	7	1	10
One Emergency Fire Pump <sup>7</sup>		0 N/A	0 N/A	0 N/A	0 N/A
One 5-Cell Cooling Tower		N/A	N/A	N/A	(4) <sup>8</sup>
<b>TOTALS</b>		<b>1,240</b>	<del><b>151</b></del> <b>186</b>	<b>46</b>	<b>458</b>

<sup>6</sup> WCEP has elected to enter RECLAIM. As such, RECLAIM Trading Credits (RTC) will be used to satisfy the NOx offsetting requirements of Rule 2005, and therefore the 30-Day Averages for NOx need not be calculated

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 24
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**Cumulative 30-Day Averages, lb/day (Non-Commissioning Year)**

	30 Day Average, lb/day				
	NOx <sup>6</sup>	CO	VOC	SOx	PM <sub>10</sub>
Five LMS100PA CTGs					
Normal Operations		766	<del>109</del> <u>145</u>	37	383
Start up		136	19	4	40
Shutdown		187	20	4	40
One Emergency Fire Pump <sup>7</sup>		∅ N/A	∅ N/A	∅ N/A	∅ N/A
One 5 Cell Cooling Tower		N/A	N/A	N/A	(4) <sup>8</sup>
<b>TOTALS</b>		<b>1,089</b>	<b><del>148</del> 184</b>	<b>45</b>	<b>463</b>

The following is a comparison of the cumulative 30-day averages for the entire facility (5-LMS100 PA gas turbines, 1-emergency fire pump, and 1-cooling tower) for both a commissioning year and a non-commissioning year. The maximum 30-day averages for each pollutant, shown in bold.

	NOx <sup>6</sup>	CO	VOC	SOx	PM <sub>10</sub>
Facility 30 Day Average (Commissioning Year)		<b>1,240</b>	<b>186</b>	<b>46</b>	458
Facility 30 Day Average (Non-Commissioning Year)		1,089	<u>184</u>	45	<b>463</b>

The following table shows the 30-day averages from one individual LMS100PA gas turbine for both a commissioning year and a non-commissioning year. The maximum 30-day averages for each pollutant are shown in bold.

	NOx <sup>6</sup>	CO	VOC	SOx	PM <sub>10</sub>
30 Day Average (Commissioning Year)		<b>248</b>	<b>37</b>	9	92
30 Day Average (Non-Commissioning Year)		218	<u>37</u>	<b>9</b>	<b>93</b>

**PROHIBITORY RULE EVALUATION**

**RULE 212-Standards for Approving Permits**

Rule 212 requires that a person shall not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. Rule 212(c) states that a project requires written notification if there is an emission increase for ANY criteria pollutant in excess of the daily maximums specified in Rule 212(g), if the equipment is located within 1,000 feet of the outer boundary of a school, or if the MICR is equal to or greater than one in a million (1EE-6) during a lifetime (70 years) for facilities with more than one permitted unit,

<sup>7</sup> The emergency fire pump is exempt from offsets (and modeling) under Rule 1304(a)(4)-Emergency Equipment if operated < 200 hr/yr

<sup>8</sup> The cooling tower is exempt from requiring a permit under Rule 219(e)(3) and consequently it is exempt from NSR. Therefore, offsets are not required for the cooling tower.



<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 25
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

source under Regulation XX, or equipment under Regulation XXX, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million (10EE-6) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or, ten in a million (10EE-6) during a lifetime (70 years) for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX. The total facility wide residential MICR is expected to be less than 1EE-6. However, since the emissions of criteria pollutants for the facility exceed the thresholds in Rule 212(g), a public notice is required in accordance with the requirements of Rule 212. A public notice ~~will be was~~ issued on November 15, 2006 ~~prior to issuance of a permit~~ followed by a 30-day public comment period. EME distributed the public notice on December 19, 2006. The engineering analysis and draft permit were on file at the La Puente Public Library for public review. Comments received include four (4) letters from EME, Perrin Manufacturing Company, Hydrogen Ventures, Inc., and SCAG and are discussed in the comments and responses section of the FDOC.

#### **FACILITY / EQUIPMENT AND SCHOOL LOCATIONS**

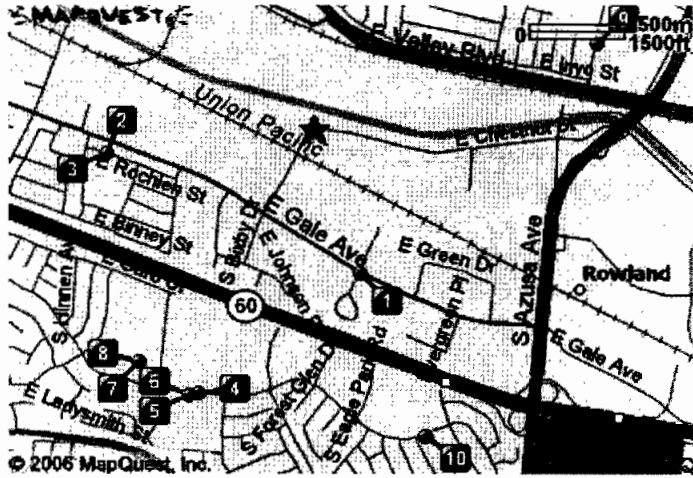
This proposed project is located at 911 Bixby Drive, City of Industry. Schools located nearest to the facility are at least a minimum of 0.41 miles away from the proposed project site as measured by the Mapquest program found at <http://www.google.com>.

As an alternate means of determining the sensitive receptor distance from the proposed site, latitude/longitude coordinates were collected at the proposed site as well as the closest sensitive receptors using a digital camera equipped with a GPS receiver. The receptor coordinates were then converted to distances, measured in feet, from the proposed site. The following table shows the distance from WCEP to each sensitive receptor as measured by (1) Mapquest and (2) using GPS coordinates (fenceline-to-fenceline)

Name of School	Address	Mapquest Distance Miles (feet)	GPS Distance (feet)
1. Premier Language Center	1200 John Reed Ct, City of Industry	0.41 (2,165)	2,586
2. Glenelder Elementary School	16234 Folger St, Hacienda Heights	0.60 (3,168)	2,997
3. Hacienda La Puente Unified	16234 Folger St Hacienda Heights	0.60 (3,168)	2,997
4. Wilson High School	16455 Wedgeworth Dr Hacienda Heights	0.80 (4,224)	2,897
5. Bixby Elementary School	16446 Wedgeworth Dr Hacienda Heights	0.81 (4,277)	Not Measured
6. Hacienda La Puente Unified	16446 Wedgeworth Dr Hacienda Heights	0.81 (4,277)	Not Measured
7. Cedarlane Middle School	16333 Cedarlane Dr Hacienda Heights	0.82 (4,330)	3,277
8. Hacienda La Puente Unified	16333 Cedarlane Dr Hacienda Heights	0.82 (4,330)	3,277
9. Hurley Elementary School	535 Dora Guzman Ave La Puente	0.85 (4,480)	Not Measured
10. Wedgeworth Elementary School	16949 Wedgeworth Dr Hacienda Heights	0.90 (4,752)	3,796

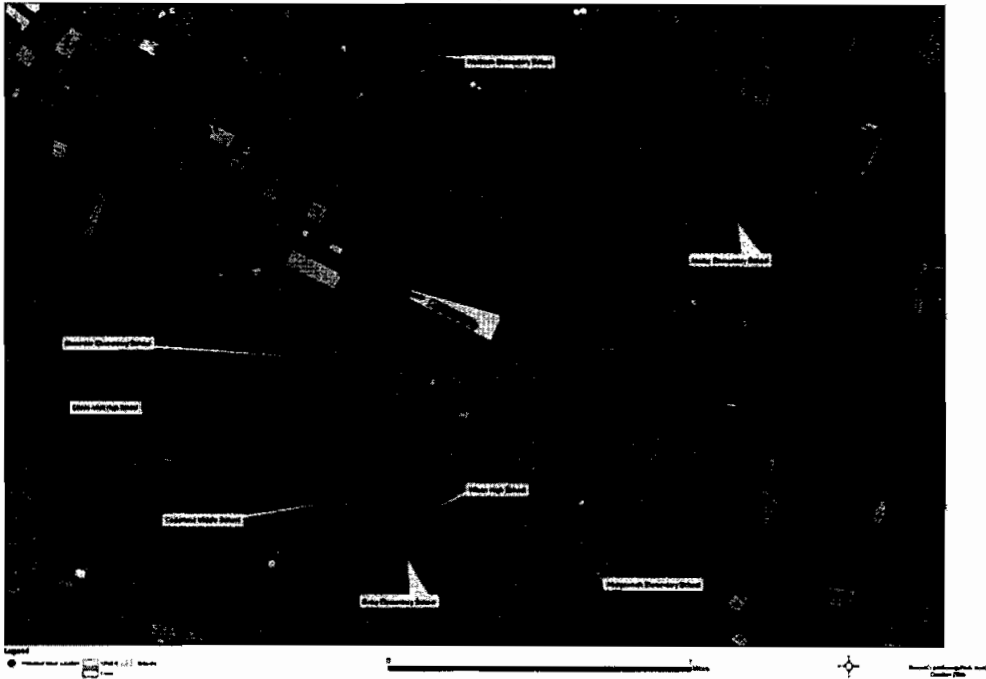
Each of the sensitive receptors are located at distances greater than 1,000 feet from the proposed WCEP site, as verified by both Mapquest and GPS coordinates. The map below is a graphical representation of the surrounding vicinity of the proposed WCEP site, which includes the locations of the sensitive receptors depicted in purple. The proposed project site is therefore not located within 1,000 feet of the outer boundary of a school.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 26
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>



Below is an aerial shot of the surrounding vicinity of the proposed Walnut Creek Energy Project. The inner circle depicts the area within 1,000 feet from the proposed site. The larger circle represents an area within 1 mile of the proposed site.

**Walnut Creek Energy Park Project**  
211 Bixby Dr., City of Industry



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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 27
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**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. It is unlikely, with the use of the SCR /CO catalyst configuration that there will be visible emissions. However, in the unlikely event that visible emissions do occur, anything greater than 20 percent opacity is not expected to last for greater than 3 minutes. During normal operation, no visible emissions are expected. Therefore, based on the above and on experience with other CTGs, compliance with this rule is expected.

**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 new turbine is not expected to create a public nuisance based on experience with identical CTGs. Therefore, compliance with Rule 402 is expected.

**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 CTGs is expected to comply with this rule.

**RULE 407-Liquid and Gaseous Air Contaminants**

This rule limits CO emissions to 2,000 ppmvd and SO<sub>2</sub> emissions to 500 ppmvd, averaged over 15 minutes. For CO, the CTGs will meet the BACT limit of 6.0 ppmvd @ 15% O<sub>2</sub>, 1-hr average, and the turbine will be conditioned as such. For SO<sub>2</sub>, equipment which complies with Rule 431.1 is exempt from the SO<sub>2</sub> limit in Rule 407. The applicant will be required to comply with Rule 431.1 and thus the SO<sub>2</sub> limit in Rule 407 will not apply.

**RULE 409-Combustion Contaminants**

This rule restricts the discharge of contaminants from the combustion of fuel to 0.1 grain per cubic foot of gas, calculated to 12% CO<sub>2</sub>, averaged over 15 minutes. The equipment is expected to meet this limit based on the calculations shown below:

Estimated exhaust gas        364,419 DSCFM = 21.87 mmscf/hr  
Maximum PM10 Emissions    6 lb/hr  
Estimated CO2 in exhaust    3%

$$\text{Grain Loading} = \frac{(6 \text{ lb/hr}) (7000 \text{ gr/lb})}{21.87 \text{ EE6 scf/hr}} \times \frac{12}{3} = 0.00768 \text{ gr/dscf} \ll 0.1 \text{ gr/dscf}$$

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SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT  ENGINEERING AND COMPLIANCE DIVISION  ENGINEERING ANALYSIS / EVALUATION	PAGES 64	PAGE 28
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**RULE 431.1-Sulfur Content of Gaseous Fuels**

WCEP will use pipeline quality natural gas which will comply with the 16 ppmv sulfur limit, calculated as H<sub>2</sub>S, specified in this rule. WCEP has provided a gas analysis which demonstrates the natural gas has a sulfur content of less than 0.25 gr/100scf, which is equivalent to a sulfur concentration of about 4 ppmv. It is also much less than the 1 gr/100scf limit typical of pipeline quality natural gas. Compliance is expected.

**RULE 474-Fuel Burning Equipment-Oxides of Nitrogen**

Superseded by NO<sub>x</sub> RECLAIM.

**RULE 475-Electric Power Generating Equipment**

This rule applies to power generating equipment rated greater than 10 MW installed after May 7, 1976. Requirements specify that the equipment must comply with a PM<sub>10</sub> mass emission limit of 11 lb/hr or a PM<sub>10</sub> concentration limit of 0.01 grains/dscf. Compliance is demonstrated if either the mass emission limit or the concentration limit is met. The PM<sub>10</sub> mass emissions from the WCEP turbines is estimated to be 6 lb/hr. The estimated grain loading is less than 0.01 grain/dscf (see calculations under Rule 409 analysis). Therefore, compliance is expected. Compliance will be verified through performance tests.

**NEW SOURCE REVIEW (NSR) ANALYSIS**

The following section describes the NSR analysis for WCEP. The facility can comply with NSR either by qualifying for various exemptions from or by demonstrating compliance with the following rules. Since WCEP is a new facility, there are no exemptions from any portions of NSR. Therefore each of the following NSR rules will apply. Each piece of equipment at WCEP is evaluated for compliance with the rules in the table below.

Table 14 - Applicable NSR Rules for WCEP

Applicable NSR Rules for Non-RECLAIM Pollutants (CO, VOC, SO <sub>x</sub> , PM <sub>10</sub> )	Applicable NSR Rules for RECLAIM Pollutants (NO <sub>x</sub> )
Rule 1303(a)-BACT	Rule 2005(b)(1)(A)-BACT
Rule 1303(b)(1)-Modeling	Rule 2005(b)(1)(B)-Modeling
Rule 1303(b)(2)-Offsets	Rule 2005(b)(2)-Offsets
Rule 1303(b)(3)-Sensitive Zone Requirements	Rule 2005(e)-Trading Zone Restrictions
Rule 1303(b)(4)-Facilitywide Compliance	Rule 2005(g)-Additional Requirements
Rule 1303(b)(5)-Major Polluting Facilities	Rule 2005(h)-Public Notice
Rule 1309.1 - Priority Reserve	Rule 2005(i)-Rule 1401 Compliance
	Rule 2005(j)-Compliance with Fed/State NSR

**RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – LMS100 CTGs**

These rules state that the Executive Officer shall deny the Permit to Construct for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia unless the applicant can demonstrate that BACT is employed for the new source. WCEP is a new source with a potential for an increase in emissions and therefore, BACT is required. Each of the LMS100 CTGs proposed for construction by WCEP will be operated on a simple cycle (no steam turbine, HRSG, or secondary electrical generator is associated with simple cycle configurations). As of the date of this evaluation, BACT for simple cycle gas turbines is shown in Table 15 below:

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 29
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**Table 15 - BACT Requirements for Simple Cycle Gas Turbines**

NOx	CO	VOC	PM <sub>10</sub> /SOx	NH <sub>3</sub>
3.5 ppmvd, at 15% O <sub>2</sub> , 3-hour rolling average	6.0 ppmvd, at 15% O <sub>2</sub> , 3-hour rolling average	2.0 ppmvd, at 15% O <sub>2</sub> , 3-hour rolling average	Pipeline quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O <sub>2</sub> , 1-hour rolling average

This information was based on a search of the BACT Clearinghouse database and the latest information available is that for a permit issued to El Colton, in January 2003. This unit is an LM6000 Sprint PC model operating on a simple cycle similar to the five CTGs being proposed by WCEP. The unit was permitted at the above emission levels and has been in operation continuously for over one year. Therefore, emission levels in Table 15 are now officially considered BACT for a simple cycle CTG. The applicant has provided a performance warranty which accompanied the initial application package which indicates that each LMS100 operating on a simple cycle can comply with, and for NOx, even exceed the above BACT requirements. The warranty was provided by GE and is included in the engineering file. The applicant is proposing the BACT levels for this project shown in Table 16 below. However, based on a Facility Permit issued to the City of Riverside (A/N 426694) in April 2005 and another Facility Permit issued to Wellhead Power Colton (A/N 439100) in May 2005, each for a simple cycle LM6000 PC Sprint CTG, the averaging times for NOx, CO, and VOC in those permits were reduced from a 3-hour rolling average to a more restrictive 1-hour rolling average. AQMD now considers the more restrictive 1-hour averaging times to be Achieved in Practice and WCEP will therefore be required to comply with the 1-hour averages for NOx, CO, and VOC.

**Table 16 - Proposed BACT for WCEP CTGs**

NOx	CO	VOC	PM <sub>10</sub> /SOx	NH <sub>3</sub>
2.5 ppmvd, @ 15% O <sub>2</sub> , @ <u>1</u> -hour average	6.0 ppmvd, @ 15% O <sub>2</sub> , @ <u>1</u> -hour average	2.0 ppmvd, @ 15% O <sub>2</sub> , @ <u>1</u> -hour average	PUC quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd @ 15% O <sub>2</sub> , 1-hour average

A NOx CEMS will be used to verify compliance with the NOx BACT limit and a CO CEMS will be used to verify compliance with the CO BACT limit. The proposed control levels in the table above will exceed the current BACT requirements for NOx and will meet current BACT requirements for all remaining criteria pollutants including NH<sub>3</sub>. BACT is satisfied for each of the CTGs.

***RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – Emergency Fire Pump***

The emergency fire pump is required to employ BACT because the maximum daily emissions from this source are expected to exceed 1 lb/day. As a starting point, the BACT Guidelines found in Part D – Non Major Polluting Facilities specify the following for emergency internal combustion engines:

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 30
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

### EPA Tier II Certification Levels Required for Compression Ignition Engines

Rating/size	Deemed Complete After	NMHC+NOx (gm/BHP-hr)	CO (gm/BHP-hr)	PM <sub>10</sub> (gm/BHP-hr)
50≤BHP<100	6/30/2004	5.6	3.7	0.30
100≤BHP<175	6/30/2003	4.9	3.7	0.22
175≤BHP<300	6/30/2003	4.9	2.6	0.15
<b>300≤BHP&lt;600</b>	<b>6/6/2003</b>	<b>4.8</b>	<b>2.6</b>	<b>0.15</b>
600≤BHP<750	6/6/2003	4.8	2.6	0.15
≥750	6/30/2006	4.8	2.6	0.15

The engine falls into the EPA Tier II BACT category highlighted in bold above. However, since WCEP will be Major Polluting Facility as defined in AQMDs BACT Guidelines, BACT for Major Sources applies. Four compression ignition emergency fire pump engines were permitted between 12/13/2000 and 12/9/2003, and the permits were issued to LA County (A/N 418342), East LA College (A/N 417691), Ultramar (A/N 395874), and Pharmavite (A/N 372822). Each of these engines drives an emergency fire pump rated between 110 bhp and 300 bhp. A closer search of AQMD's BACT Clearinghouse for each of these engines reveals no significant advancements in BACT determinations for this category of engine. As for PM<sub>10</sub>, diesel fired engines are currently employing particulate traps to control PM<sub>10</sub> emissions. As such, EME will be required to evaluate the technological feasibility of using a particulate trap on the emergency fire pump. In the event that it is not technologically feasible to install a particulate trap to control PM<sub>10</sub> emissions, the Tier II BACT levels will apply to the emergency fire pump, unless it can be demonstrated, according to AQMD BACT Guidelines, that there are currently no UL listed fire pumps which can meet Tier III emission standards. In that case, Tier II limits will apply.

EME has submitted a letter dated December 11, 2006 from Clarke, the engine manufacturer, which indicates the installation of after-treatment devices such as particulate traps will compromise reliability and performance and most importantly, safe operation of the fire pump, and that its installation would most likely void the fire pump's UL certification. Therefore, EME proceeded to investigate the possibility of purchasing an engine which will comply with the Tier III emission standards. Currently, according to EME, in a letter dated December 18, 2006 from Clarke, fire pumps which are UL certified that can meet Tier III standards are currently not being provided or sold and are still in development. Therefore, the Tier II standards apply to this fire pump. BACT for SOx emissions for compression ignition emergency fire pumps is diesel fuel with a sulfur content no greater than 0.0015% by weight. A BACT summary for the emergency fire pump is shown below.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 31
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**Proposed BACT for Emergency Fire Pump (A/N 45094308)**

Pollutant	EPA Tier II Levels	Proposed BACT	Comply (Yes/No)
NOx+NMHC	4.8 gm/BHP-hr	4.65 gm/BHP-hr	Yes
CO	2.6 gm/BHP-hr	0.45 gm/BHP-hr	Yes
PM <sub>10</sub>	0.15 gm/BHP-hr	0.09 gm/BHP-hr or particulate trap	<del>Yes</del> Under evaluation for feasibility of particulate trap (Will meet emission limit in lieu of particulate trap).
SOx	On or after June 1, 2004 the user may only purchase diesel fuel with a sulfur content no greater than 0.0015% by weight (Rule 431.2)		Yes

The manufacturer has indicated that this engine can comply with the Tier II emission levels specified above, and the user will only purchase diesel fuel with a sulfur content of no greater than 0.0015% by weight. The emergency fire pump is expected to comply with BACT.

***RULE 1303(a)-BACT – Cooling Tower***

Rule 219(e)(3) provides an exemption for water cooling towers and water cooling ponds not used for evaporative cooling of process water or not used for evaporative cooling of water from barometric jets or from barometric condensers and in which no chromium compounds are contained. The 5-cell cooling tower being proposed at WCEP will meet the requirements of Rule 219(e)(3) and is therefore exempt from NSR. BACT therefore does not apply.

***RULE 1303(a)-BACT – Ammonia Storage Tank***

A pressure relief valve that will be set at no less than 25 psig will control ammonia emissions from the storage tank. In addition, a vapor return line will be used to control ammonia emissions during storage tank filling operations. Based on the above, compliance with BACT requirements is expected.

Based on the above BACT analysis for the entire project, the 5 CTGs and the emergency fire pump will comply with the current BACT requirements found in Regulation XIII (for the non-RECLAIM pollutants) and in Regulation XX (for the RECLAIM pollutants). BACT for all equipment is satisfied.

***RULE 1303(b)(1) and Rule 2005(b)(1)(B) – Modeling:***

The applicant has conducted air dispersion modeling using the EPA Industrial Source Complex Short Term ISCST3 air dispersion model, Version 3. The Tier 4 Health Risk Assessment was conducted in accordance with guidelines set forth by the California Office of Environmental Health Hazard Assessment (OEHHA) and the California Air Resources Board (CARB). The OEHHA/CARB computer program (HARP) was used to determine the health risk assessment. The air dispersion model was run at a single normalized emission rate of 1.0 gram/sec. The applicant has submitted modeling results for both a commissioning and non-commissioning year which considered building downwash effects through the use of the EPA Building

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 32
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

Profile Input Program, a program which is compatible with the ISCST3 model. Effects of terrain slope, aspect ratio, plume height, wind speed, wind direction and temperature were also accounted for in the analysis. The data was collected at the AQMD's Walnut monitoring station. The analysis further accounted for flat, simple, intermediate, and complex terrain. Terrain features were taken from 1-second U.S. Geological Survey (USGS) data taken from its Digital Elevation Model (DEM). The DEM data provides terrain elevations with 1-meter vertical resolution and 10-meters horizontal resolution based on a UTM coordinate system. The EPA SCREEN3 model was used to estimate potential impacts due to fumigation. Potential fumigation impacts were estimated for NO<sub>2</sub>, CO, and SO<sub>2</sub>. Table A-2 shown below is found in Rule 1303 and lists the most stringent ambient air quality standards and allowable change in concentration for each air contaminant. The appropriate averaging times are also listed.

Table A-2  
Most Stringent Ambient Air Quality Standard and  
Allowable Change in Concentration  
For Each Air Contaminant/Averaging Time Combination

Air Contaminant	Averaging Time	Most Stringent Air Quality Standard		Significant Change in Air Quality Concentration	
Nitrogen Dioxide	1-hour	25 pphm	500 µg/m <sup>3</sup>	1 pphm	20 µg/m <sup>3</sup>
	Annual	5.3 pphm	100 µg/m <sup>3</sup>	0.05 pphm	1 µg/m <sup>3</sup>
Carbon Monoxide	1-hour	20 ppm	23 µg/m <sup>3</sup>	1 pphm	1.1 µg/m <sup>3</sup>
	8-hour	9.0 ppm	10 µg/m <sup>3</sup>	0.45 pphm	0.50 µg/m <sup>3</sup>
Suspended Particulate Matter <10µm (PM <sub>10</sub> )	24-hour		50 µg/m <sup>3</sup>		2.5 µg/m <sup>3</sup>
	AGM <sup>9</sup>		30 µg/m <sup>3</sup>		1 µg/m <sup>3</sup>
Sulfate	24-hour		25 µg/m <sup>3</sup>		1 µg/m <sup>3</sup>

The applicant is required under Rule 1303(b)(1) to demonstrate compliance with one of the following requirements:

- (a) The most stringent air quality standard shown in Table A-2 above, or
- (b) The significant change in air quality concentration standards shown in Table A-2 above, if the most stringent air quality standards are exceeded

The applicant has submitted the following modeled maximum project impacts for each individual turbine at WCEP. Therefore, the numbers in the table below are on a permit unit basis ~~cumulative for the entire facility~~. Each individual turbine plus the background concentration is less than the most stringent standard.

Maximum Project Impacts for WCEP for Attainment Pollutants

	Average	CTG No.1	CTG No.2	CTG No.3	CTG No.4	CTG No.5	Bkgrnd (µg/m <sup>3</sup> )	Most Stringent Standard (µg/m <sup>3</sup> )	Comply (Yes/No)
		<u>          </u>	<u>          </u>	<u>          </u>	<u>          </u>	<u>          </u>			
NOx	1-hour	5.46	5.45	5.46	5.46	5.46	297	470	Yes
	Annual	0.1604	0.1604	0.1602	0.1610	0.1603	67.9	100	Yes
SO <sub>2</sub>	1-hour	0.541	0.541	0.541	0.541	0.541	52.4	650	Yes
	3-hour	0.518	0.518	0.518	0.518	0.518	52.4	1,300	Yes
	24-hour	0.171	0.170	0.172	0.172	0.171	23.5	109	Yes
	Annual	0.0122	0.0119	0.0116	0.0109	0.0103	8	80	Yes
CO	1-hour	8.69	8.69	8.71	8.73	8.69	12,571	23,000	Yes
	8-hour	8.06	8.06	8.14	8.18	8.059	4,989	10,000	Yes

<sup>9</sup> AGM is the acronym for Annual Geometric Mean

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SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT  ENGINEERING AND COMPLIANCE DIVISION  ENGINEERING ANALYSIS / EVALUATION	PAGES 64	PAGE 33
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

As can be seen from the table above, on a cumulative basis, both the 24-hour and AGM air quality standards for PM<sub>10</sub> will be exceeded. Therefore, the applicant will be required to show compliance with the significant change in air quality standards for PM<sub>10</sub>. The applicant has submitted PM<sub>10</sub> concentrations from each individual piece of equipment (shown in the table below) and has listed the concentrations separately so as to indicate that on an individual basis, each turbine on its own can demonstrate compliance with the Rule 1303 significance thresholds shown in Table A-2 above, for both the 24-hour and the AGM averaging periods. Since PM<sub>10</sub> is a non-attainment pollutant, it is required to comply with the 24-hour and annual PM<sub>10</sub> significance levels in the table below. This table shows the 24-hour and the annual significance levels for turbines 1 through 5.

Significance Modeling for SVEP WCEP for Non-Attainment Pollutants, ( $\mu\text{g}/\text{m}^3$ )

Equipment	24-hour PM <sub>10</sub> Concentration	24 hour PM10 Significance Level	Annual PM10 Concentration	Annual PM10 Significance Level	Comply (Yes/No)
Turbine No. 1	1.435	2.5	0.119	1	Yes
Turbine No. 2	1.441	2.5	0.116	1	Yes
Turbine No. 3	1.649	2.5	0.113	1	Yes
Turbine No. 4	1.601	2.5	0.107	1	Yes
Turbine No. 5	1.349	2.5	0.101	1	Yes
Fire Pump	0.014	2.5	0.001	1	Yes

AQMD modeling staff reviewed the applicant's analyses for both air quality modeling and health risk assessment (HRA). Modeling staff provided their comments in a memorandum from Ms. Jill Whynot to Mr. Mike Mills dated August 30, 2006. A copy of this memorandum is contained in the engineering file. Staff's review of the modeling and HRA analyses concluded that the applicant used EPA ISCST3 model version 02035 along with the appropriate model options in the analysis for NO<sub>2</sub>, CO, PM<sub>10</sub>, and SO<sub>2</sub>. The applicant modeled both the cumulative and individual permit unit impacts for the project. The memorandum states that the ISCST3 modeling as performed by the applicant conforms to the District's dispersion modeling requirements. No significant deficiencies in methodology were noted.

***RULE 1303(b)(2) and Rule 2005(b)(2)-Offsets – LMS100 PA CTGs:***

Since WCEP is a new facility with an emissions increase, offsets will be required for all criteria pollutants. WCEP will be included in NO<sub>x</sub> RECLAIM and as such, NO<sub>x</sub> increases will be offset with RTCs at a 1.0 to 1 ratio. Non-RECLAIM criteria pollutants (CO, VOC, SO<sub>x</sub>, and PM<sub>10</sub>) will be offset by either the purchase of Emission Reduction Credits (ERCs) and/or Priority Reserve Credits (PRCs), if eligible, based on the version of Rule 1309.1 in effect at the time of issuance of a Permit to Construct, at a 1.2 to 1 ratio. The facility may elect to offset emission increases using either purchased ERCs or PRCs or any combination thereof as allowed by AQMD Rules and Regulations. The required RTCs for NO<sub>x</sub> for the first and second years of operation are shown below. The values include start-ups, commissioning (first year only), normal operation, and shutdowns. (The total emissions for the second year excludes commissioning).

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 34
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**REQUIRED NOx RTCs**

Operating Condition 100	Hours per Year	NOx (lb/hr)	NOx (lb/year) per device	NOx (lb/year) cumulative
<b>CTGs</b>				
Startup	350	<del>12.00</del> 10.42	<del>4,200.00</del> 3,647.00	<del>21,000.00</del> 18,235.00
Shutdown	350	<del>10.92</del> 11.00	<del>3,822.00</del> 3,850.00	<del>19,110.00</del> 19,250.00
Normal Operation	2,634	8.21	21,625.14	108,125.70
Commissioning	134	71.21	9,542.14	47,710.70
<b>CTG Totals</b>	<b>3,468</b>		<del>39,189.28</del> 38,664.28	<del>195,946.00</del> 193,321.40
Emergency Fire Pump	199	10.54	2,097.46	2,097.46
Total 1st Year Emissions (lb/year)			<del>41,286.74</del> 40,761.74	<del>198,043.86</del> 195,418.86
Offset Ratio			1.00	1.00
1st year RTCs (lb/year)			<del>41,287.00</del> 40,761.74	<del>198,044.00</del> 195,418.86
2nd year RTCs (lb/year)			<del>31,745.00</del> 32,319.74	<del>150,333.00</del> 153,208.86

Table 17 shows the facility-wide 30-day averages for CO, VOC, PM<sub>10</sub> and SO<sub>x</sub> for informational purposes only. Offsets are based upon 30-day averages from individual permit units. As mentioned above, WCEP may elect to use both ERCs and PRCs to provide the required offsets, as shown below, however, PRCs are only available for CO, PM<sub>10</sub>, and SO<sub>x</sub>, as depicted in the table below. The amounts in Table 18 are required to fully offset the facility increases and satisfy the requirements of Rule 1303(b)(2): Note maximum 30-day average for PM<sub>10</sub> excludes the emissions from the cooling tower per Rule 219(e)(3).

**Table 17 – 30-Day Averages for the Entire Facility, (lb/day)**

	NOx	CO	VOC	SOx	PM <sub>10</sub>
Maximum 30 Day Average		1,240	<del>151</del> 186	46	463

**Table 18 - Required Offsets for Non-RECLAIM Pollutants (per-turbine basis, lb/day)**

	NOx	CO	VOC	SOx	PM <sub>10</sub>
Maximum 30 Day Average		248	37	9	93
ERC Offset Ratio		1.2	1.2	1.2	1.2
PRC Offset Ratio		1.2	N/A	1.2	1.2
Required Offsets if ERCs are chosen		<b>298</b>	<b>44</b>	<b>11</b>	<b>112</b>
Required Offsets if PRCs are chosen		<b>298</b>	<b>N/A</b>	<b>11</b>	<b>112</b>

NOTE: Changes to the PDOC issued October 31, 2006 are denoted by underlined additions and ~~strikethrough~~ deletions

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 35
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

The facility's maximum monthly and annual fuel usage (caps) for the simultaneous operation of the 5 CTGs will be 1,966 mmscf and 14,725 mmscf, respectively, based on operating condition 100. The annual fuel cap will be the basis for the facility's PTE. The monthly and annual fuel caps will correspond to 463 hours/month and 3,468 hours/year of operation. These values were selected by WCEP.

The monthly and annual fuel caps for the emergency fire pump are 264 gallons and 3,184 3,200 gallons, respectively. The calculations are shown below and a monthly fuel cap will be included on the Facility Permit as a permit condition.

Monthly:

CTGFuel= (803.3 MMBTU/hr)\*1.11\*(1 scf/1,050 BTU) (463 hr/month) (5 CTGs) = 1,966 MMscf/month  
ICEFuel= (16.0 gal/hr)\*16.5 hr/month = 264 gal/month

Annually:

CTGFuel= (803.3 MMBTU/hr)\*1.11\*(1 scf/1,050 BTU) (3,468 hr/year) (5 CTGs) = 14,725 MMscf/year  
ICEFuel= (16.0 gal/hr)\*199.99 hr/year = ~~3,184~~ 3,200 gal/year

Table 19 below shows the total amount of ERC's that EME has purchased as of ~~October 26, 2006~~ February 7, 2007. The table consists of one ERC certificate for VOC as shown. (~~certificate no. AQ003679~~) purchased on October 23, 2006 from Electrofilm Manufacturing Company in the amount of 8 lb/day. Shaded areas in the table indicate that no ERC's for that pollutant have been acquired by EME as of ~~October 26, 2006~~ February 7, 2007.

Table 19 – Total Amount of Emission Reduction Credits currently held by EME, Walnut Creek Energy, LLC

Pollutant	ERC Certificate No.	Date of Purchase	Origin <del>Name of Seller</del>	Seller	Amount of ERC (lb/day)
VOC	AQ003679	10/23/2006	Electrofilm Manufacturing	Electrofilm Manufacturing	8
VOC	AQ002683	11/8/2006	Magnatek, Inc	Magnatek, Inc	1
VOC	AQ006303	11/13/2006	Scope Products	Greg K Environmental Fund	100
VOC	AQ004209	11/13/2006	Plastic Dress Up Co	Dart Container Corp	117
CO					
PM10					
SOx					

WCEP has indicated that the required amounts of offsets will be provided prior to issuance of the Facility Permit. Compliance with offset requirements of Rules 1303(b)(2) and 2005(b)(2) is expected.

***RULES 1303(b)(3)-Sensitive Zone Requirements and 2005(e)-Trading Zone Restrictions:***

Both rules state that credits must be obtained from the appropriate trading zone. In the case of Rule 1303(b)(3), unless credits are obtained from the Priority Reserve, facilities located in the South Coast Air Basin are subject to the Sensitive Zone requirements specified in Health & Safety Code Section 40410.5. WCEP is located in Zone 2a and is therefore eligible to obtain its ERCs from either Zone 1 or Zone 2a. Similarly in the case of Rule 2005(e), WCEP, because of its location may obtain RTCs from either Zone 1 or Zone 2, at its choosing. Compliance is expected with both rules.

NOTE: Changes to the PDOC issued October 31, 2006 are denoted by underlined additions and ~~strikethrough~~ deletions

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT  ENGINEERING AND COMPLIANCE DIVISION  ENGINEERING ANALYSIS / EVALUATION	PAGES 64	PAGE 36
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**RULE 1303(b)(4)-Facility Compliance:**

The new facility will comply with all applicable Rules and Regulations of the AQMD.

**RULE 1303(b)(5)-Major Polluting Facilities:**

**Rule 1303(b)(5)(A) – Alternative Analysis**

The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the WCEP and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. EME has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility.

**Rule 1303(b)(5)(B) – Statewide Compliance**

EME has certified in the 400-A form that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. In addition, EME has submitted an email to the AQMD dated October 19, 2006 stating that “any and all facilities that EME owns or operates in the State of California (including the proposed WCEP) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Therefore, compliance is expected.

**Rule 1303(b)(5)(C) – Protection of Visibility**

Modeling is required if the source is within a Federal Class I area and the NOx and PM10 emissions exceed 40 TPY and 15TYP respectively. Since the nearest Federal Class I area is located over 28 miles from the proposed WCEP site, modeling from plume visibility is not required, however, the applicant has provided modeling impact data for the Federal Class I areas as part of the AFC process. Compliance is expected.

**Rule 1303(b)(5)(D) – Compliance through CEQA**

The California Energy Commission’s (CEC) certification process is essentially equivalent to CEQA. Since the applicant is required to receive a certification from the CEC, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected.

**RULE 1309.1-Priority Reserve:**

This rule requires an electrical generating facility (EGF) to comply with the requirements in R-1309(c): As part of the recent amendments to Rule 1309.1-Priority Reserve, (September 8, 2006), the AQMD Executive Officer committed to hold a public meeting for each project prior to accessing the Priority Reserve. AQMD held a public meeting to inform the public about the specifics of the proposed project. The meeting was held on October 17, 2006. Topics discussed included facility emissions, local impacts on schools, and surrounding area. The requirements and compliance status are summarized in Table 20 below:

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 37
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

Table 20 - Rule 1309.1 Requirements and Compliance Determination

REQUIREMENTS	COMPLIANCE (Yes/No)
<b>Rule 1309.1(c) (1)</b> - Permit condition requiring facility to comply with BARCT for pollutants received from Priority Reserve for all existing sources prior to operation of any new sources	<b>(YES)</b> Since there are no existing sources at this facility, BARCT is not applicable and the new equipment will be constructed using BACT for simple cycle power plants. These emission limits the lowest levels achieved in practice under federal LAER. Compliance is expected
<b>Rule 1309.1(c) (2)</b> - The applicant must pay a mitigation fee pursuant to subdivision (g)	<b>(YES)</b> The applicant will pay this fee for each pollutant upon securing PRCs.
<b>Rule 1309.1(c) (3)</b> - Conducts due diligence effort approved by the Executive Officer to secure ERCs for requested Priority Reserve pollutants	<b>(CONTINUOUS PENDING)</b> The applicant has submitted written correspondence to AQMD (see letter in file dated September 27, 2006 from Latham & Watkins to Mr. Mohsen Nazemi) which indicates the applicant is in the process of attempting to secure ERCs for the requested Priority Reserve pollutants. AQMD has received a letter dated September 27, 2006 which provided information regarding the progress in securing offsets for WCEP. <u>EME secured additional VOC ERCs on October 23, November 8, and November 13, 2006 for a total of 226 lb/day. No additional ERCs have been purchased as of February 7, 2007.</u> EME will continue to provide progress reports the ERCs are secured.
<b>Rule 1309.1(c) (4)</b> - Applicant has the new source fully and legally operational at rated capacity within 3 years following AQMD permit to Construct issuance or CEC certification, whichever is later	<b>(YES)</b> The applicant is scheduled to have the new facility fully operational at its rated capacity by July 2008.
<b>Rule 1309.1(c) (5)</b> - Applicant must enter into a long-term contract with the State of California to sell at least 50% of the portion of power which it has generated using PRCs	<b>(YES)</b> The applicant is a power generator and is engaged in the sale of generated power to end users. Most of the power will be supplied to the state's electrical grid. However, at this time, it is the AQMD's understanding that the State of California is not offering long term contracts for the acquisition of power.
<b>Rule 1309.1(c) (6)</b> - Applicant for an in-Basin EGF must purchase PRCs at an offset ratio of 1.2 -to-1.0	<b>(YES)</b> The applicant has proposed to purchase both ERCs and PRC at an offset ration of 1.2-to-1.0.
<b>Rule 1309.1(c) (7)</b> - Applicant for a Downwind Air Basin EGF shall obtain credits at an offset ratio as determined by the downwind air district	<b>(NOT APPLICABLE)</b> This facility is located within the South Coast Air Basin (SCAB) and the applicable offset ratio for PRCs in the SCAB is 1.2-to-1.0.
<b>Rule 1309.1(c) (8)</b> - Applicant for Permit to Construct must agree to a permit condition which requires new sources to be fully and legally operational at rated capacity within 3 years. An applicant that is a municipality must have an additional year if the EGF contains a renewable energy component with a rated capacity of at least 50 MW of renewable energy.	<b>(YES)</b> The applicant is scheduled to have the new facility fully operational at its rated capacity by July 2008.
<b>BASED ON THE INFORMATION IN THIS TABLE, WCEP CAN COMPLY WITH THE APPLICABLE REQUIREMENTS OF RULE 1309.1</b>	

NOTE: Changes to the PDOC issued October 31, 2006 are denoted by underlined additions and ~~strikethrough~~ deletions

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT  ENGINEERING AND COMPLIANCE DIVISION  ENGINEERING ANALYSIS / EVALUATION	PAGES 64	PAGE 38
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**Proposed Amendments to Rule 1309.1 – Priority Reserve**

To provide the public residing in more polluted areas with added protection and incentivizing the siting of new power plants in less polluted areas, in adopting the amendments to Rule 1309.1, the AQMD Governing Board directed staff to develop additional requirements for power plants proposing to locate in the more polluted areas within the District. In response to the Governing Board's directive, staff has developed several proposed options for the Governing Board's consideration. The proposed amendments include options that set additional criteria, including higher mitigation fees, for those power plants proposing to locate in more polluted areas and are seeking access to Priority Reserve and for some options, amendments that would prohibit power plants locating in the most polluted areas from accessing the Priority Reserve. Each of the proposed amendment options subdivide the Basin into three zones (Zone 1, Zone 2, and Zone 3) based on the average PM<sub>2.5</sub> concentrations observed for years 2003 through 2005. These zones correspond to health-based exposure levels and are used as a criteria for both eligibility to access the Priority Reserve and the mitigation pricing of Priority Reserve credits. Zone 1 indicates includes those areas of less than 18 µg/m<sup>3</sup>. Zone 2 includes those areas with concentrations between 18 µg/m<sup>3</sup> and 20 µg/m<sup>3</sup>, and Zone 3 includes those areas with a concentration of greater than 20 µg/m<sup>3</sup>. Outlined below is a basic summary of the requirements of options A through F and the individual impact each option may have on WCEP. The Governing Board has set a hearing to consider adoption of one of these rule options at its regular meeting scheduled for March 2, 2007.

PROPOSED ADDITIONAL RULE 1309.1 REQUIREMENTS FOR NEW POWER PLANTS PROPOSING ACCESS TO AQMD PRIORITY RESERVE (PR)	
Rule Amendment Option	Impact of Option on Walnut Creek Energy Project
<u>Option A:</u> Power plants in Zone 1,2, and 3 can purchase PM10, SOx and CO credits from PR, except that in addition, power plants located in Zones 2 & 3 must also demonstrate MICR from power plant <1EE-6, HIA and HIC from power plant <0.5, and CB from power plant ≤ than 0.1	WCEP is located in Zone 2. Therefore, since the MICR, HIA, HIC for this project are all less than the amounts in Option 1, WCEP can access PR. Because of its proposed location in Zone 2, WCEP will pay higher mitigation fees as follows: PM10: \$75,626; SOx:\$22,625; and CO:\$18,000. MICR = 6.23EE-7 HIA = 0.0635 HIC = 0.0124 Cancer Burden (CB) = 0.000337
<u>Option B:</u> Is Option A plus "cancer risk area" (CRA). CRA is the area in the basin experiencing the top 5% of cancer risk from airborne toxics. Projects in the CRA subject to same requirements as those in Zone 3. Mitigation fees are double those of Zone 1.	WCEP is located in Zone 2, and is not located in a Cancer Risk Area (CRA). Therefore, Option B does not change the requirements of Option A.
<u>Option C:</u> Is Option A except that power plants in Zone 3 are not authorized to access the PR and must obtain their offset credits on the open market.	WCEP is in Zone 2. Therefore Option C does not change the requirements of Option A.
<u>Option D:</u> Is Option B except that power plants in Zone 3 or a CRA are not authorized to access the PR and must obtain their offset credits on the open market.	WCEP is in Zone 2. Therefore Option D does not change the requirements of Option B.

NOTE: Changes to the PDOC issued October 31, 2006 are denoted by underlined additions and ~~strikethrough~~ deletions

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 39
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

<b>PROPOSED ADDITIONAL RULE 1309.1 REQUIREMENTS FOR NEW POWER PLANTS          PROPOSING ACCESS TO AQMD PRIORITY RESERVE (PR)</b>	
Rule Amendment Option	Impact of Option on Walnut Creek Energy Project
<u>Option E:</u> Is Option C except that it will allow municipal power plants located in Zone 3 that receive 30% or more of their power, by December 31, 2012, from renewable sources to purchase credits from the PR subject to meeting all other provisions of Option C.	WCEP is in Zone 2 and is not a municipal power plant. Therefore Option E does not change the requirements of Option C.
<u>Option F:</u> Is Option C except that it will allow a peaking unit with a rating of not more than 100 MW located in Zone 3 to purchase credits from the PR subject to meeting all other provisions of the rule option including subclauses (b)(5)(A)(ii)(I), (b)(5)(A)(ii)(II), and (b)(5)(A)(ii)(III) and paying twice the mitigation fee of subparagraph (g)(1)(B).	WCEP is in Zone 2 and is not a peaking plant as defined in this rule option (<2,000 hrs/yr of operation time). Therefore Option F does not change the requirements of Option C.

Therefore, based on the table above, only Option A applies to WCEP. The net impact of this option is that although WCEP will continue to have access to the PR, the facility will pay mitigation fees that are 50% more than those for projects located in Zone 1. None of the other options as proposed will impose additional requirements to WCEP.

**Rule 1401 – New Source Review of Toxic Air Contaminants:**

This rule specifies limits for maximum individual cancer risk (MICR), acute hazard index (HIA), chronic hazard index (HIC) and cancer burden (CB) from new permit units, relocations, or modifications to existing permits which emit toxic air contaminants. Rule 1401 requirements are summarized as follows:

Table 21 – Rule 1401 Requirements

Parameters and Specifications	Rule 1401 Requirements
MICR, without T-BACT	$\leq 1 \times 10^{-6}$
MICR, with T-BACT	$\leq 1 \times 10^{-5}$
Acute Hazard Index	$\leq 1.0$
Chronic Hazard Index	$\leq 1.0$
Cancer Burden	$\leq 0.5$

The applicant performed a Tier 4 health risk assessment using the Hot Spots Analysis and Reporting Program (HARP, version 1.2a). The analysis included an estimate of the MICR for the nearest residential and commercial receptors, the acute and chronic hazard indices for the entire facility. PRA modeling staff reviewed the applicant's methodology and procedures used, and re-ran the HARP model and verified the health risk and hazard indices which were presented by the applicant. PRA staff concluded that each of the health risk values for MICR, HIA and HIC were appropriately estimated (see memorandum in file, dated August 30, 2006 from Ms. Jill Whynot to Mr. Mike Mills). Table 22 below is a summary of the modeled health risk assessment results. The cancer burden is not calculated because the MICR is less than  $1 \times 10^{-6}$  for both residential and commercial receptors.

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	PAGES 64	PAGE 40
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

Table 22 – Rule 1401 Modeled Results

Risk Parameter	Residential	Commercial	Rule 1401 Requirements	Compliance (Yes/No)
MICR	$6.23 \times 10^{-7}$	$1.06 \times 10^{-9}$	$\leq 1 \times 10^{-6}$	Yes
HIA	0.0635	0.000879	$\leq 1.0$	Yes
HIC	0.0124	0.0000156	$\leq 1.0$	Yes
Receptor UTM's	413480E / 3764940N	413123E / 3763141N		

Table 22 shows that WCEP will comply with the applicable requirements of Rule 1401. The cancer burden is not computed because the highest MICR (in this case, the residential MICR) is less than  $1 \times 10^{-6}$ .

***RULE 1470-Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines:***

Rule 1470 imposes the following requirements on compression ignition engines:

Paragraph (c)(1) requires the use of CARB Diesel fuel. The use of No. 2 diesel fuel will satisfy this requirement. Paragraph (c)(2)(A) imposes operating requirements for engines located within 500 feet from a school. Since the engine is located greater than 500 feet to the nearest school, the requirements of this section are not applicable.

Paragraph (c)(2)(B) allows operation of this device during an impending rotating electric power outage only if:

1. The permit specifically allows this operation
2. The utility company has actually ordered the outage
3. The engine is in a specific location covered by the outage.
4. The engine is operated no more than 30 minutes prior to the outage, and
5. The engine operation is terminated immediately after the outage.

AQMD will require a condition to limit the maintenance and testing to less than 50 hours per year. This engine is expected to meet these requirements.

Paragraph (c)(2)(C) limits hours for maintenance and testing to 50 hours per year for PM<sub>10</sub> emissions up to 0.15 gm/bhp-hr, and a maximum of 100 hours per year for PM<sub>10</sub> emissions up to 0.01 gm/bhp-hr. Therefore, the engine will comply with paragraph (c)(2)(C). Also, part (iv) of paragraph (c)(2)(C) requires that the engine meet the standards for off road engines in Title 13, CCR section 2423. This engine will comply with the requirements for off road engines. Therefore, compliance with Rule 1470 is expected.

***Rule 2005(g) – Additional Requirements***

As with Rule 1303(b)(5) for the Non-RECLAIM pollutants, WCEP has addressed the alternative analysis, statewide compliance, protection of visibility, and CEQA compliance requirements of this rule for NOx. These requirements are essentially the same as those found in Rule 1303(b)(5), subparts A through D for non-RECLAIM pollutants, and are summarized below.



SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT  ENGINEERING AND COMPLIANCE DIVISION  ENGINEERING ANALYSIS / EVALUATION	PAGES 64	PAGE 41
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**Rule 2005(g)(1) – Statewide Compliance**

EME has certified in the 400-A form that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. In addition, EME has submitted an email to the AQMD dated October 19, 2006 stating that “any and all facilities that EME owns or operates in the State of California (including the proposed WCEP) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Therefore, compliance is expected.

**Rule 2005(g)(2) – Alternative Analysis**

The applicant is required to conduct an analysis of alternative sites, sizes, production processes, environmental control techniques for the WCEP and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. EME has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility.

**Rule 2005(g)(3) – Compliance through CEQA**

The California Energy Commission’s (CEC) certification process is essentially equivalent to CEQA. Since the applicant is required to receive a certification from the CEC, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected

**Rule 2005(g)(4) – Protection of Visibility**

Modeling is required if the source is within a Class I area and the NOx emissions exceed 40 TPY. Since the nearest Class I area is located over 28 miles from the proposed WCEP site, modeling from plume visibility is not required, however, the applicant has provided modeling impact data for the Class I areas as part of the AFC process. Compliance is expected

***Rule 2005(h) – Public Notice***

WCEP will comply with the requirements for Public Notice found in Rule 212. Therefore compliance with Rule 2005(h) is demonstrated.

***Rule 2005(i) – Rule 1401 Compliance.***

WCEP will comply with Rule 1401 as demonstrated in the Tier 4 analysis and subsequently reviewed and found to be satisfactory by AQMD modeling staff. Compliance is expected.

***Rule 2005(j) – Compliance with State and Federal NSR.***

WCEP will comply with the provisions of this rule by having demonstrated compliance with AQMD NSR Regulations XIII and Rule 2005-NSR for RECLAIM.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 42
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**REGULATION XVII – Prevention of Significant Deterioration**

The District Governing Board in its action on February 7, 2003, authorized the Executive Officer, upon withdrawal of the EPA PSD delegation, not to request any further delegation and to allow the EPA to terminate the AQMD's PSD delegation agreement and for EPA to become the permitting agency for PSD sources in the AQMD.

The Board determined that Regulation XVII is inactive upon EPA's withdrawal of delegation and shall remain inactive unless and until the EPA provides the AQMD with new delegation of authority to act either in full or on a Facility/Permit-Specific basis. The delegation was rescinded on March 3, 2003 by EPA.

The District Governing Board in its April 1, 2005 meeting reaffirmed its previous action on February 7, 2003 to relinquish PSD analysis back to federal government and render Regulation XVII inactive unless the District receives new delegation in part or in full from the EPA.

Based on the Governing Board's actions, this rule is ineffective and no analysis is required for any pollutant subject to federal PSD requirement. The AQMD has sent the applicant a notification to contact the EPA directly for applicability of PSD to the proposed project. AQMD sent a letter to the applicant on December 8, 2005 and instructed to contact EPA directly regarding implementation of PSD.

**INTERIM PERIOD EMISSION FACTORS**

RECLAIM requires a NOx emission factor to be used for reporting emissions during the interim reporting period. The interim period is defined as a period, typically 12 months in duration, when the CEMS has not been certified. During this period, the emissions cannot be accurately quantified, monitored, or verified. The emissions during this period are assumed to be at uncontrolled levels. The interim reporting period can be broken down into the two parts which includes the commissioning period in which an uncontrolled<sup>10</sup> emission rate is assumed, and the remaining period at which controlled rates at BACT are assumed. Since WCEP will be included in NOx RECLAIM, an interim period emission factor will be determined. Although not a RECLAIM pollutant, a CO emission factor will also be calculated so that the applicant may use it to report emissions during the interim period when the CEMS is not yet certified for CO. In the event CEMS data is not available, NOx, CO, and SOx emissions during the interim period will be calculated using monthly fuel usage and the emission factors derived below. There will be two interim period emission factors calculated for NOx and two interim period emission factors calculated for CO. The first factor will be for use during commissioning stage when the CTGs are assumed to be operating at uncontrolled levels and the second factor will be for use after commissioning is complete and the CTGs are assumed to operate at BACT levels. SOx is not affected by the presumed absence of emission controls which occurs during commissioning because the SCR and CO catalyst modules control only NOx and CO emissions and to a lesser degree, VOC. Consequently, SOx emissions are assumed to be equal both during and after commissioning and therefore, only one SOx emission factor for the 12 month interim period will be computed. The specific calculations are shown in Appendix G and the results are shown in the tables below.

<sup>10</sup> The emission factor for the commissioning period is an average for the entire 134 hour period. During this period, the turbines may be uncontrolled, partially controlled, or 100% controlled.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 43
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

Commissioning Period

Pollutants	NOx	CO
Total emissions (lbs)	47,710	48,640
Total Fuel (mmscf)	386.43	386.43
Emission Factor (lb/mmscf)	<b>123.46</b>	<b>125.87</b>

Remaining Period (Non-Commissioning)

Pollutants	NOx	CO
Total emissions (lbs)	<del>153,736</del> 145,610	<del>261,280</del> 242,740
Total Fuel (mmscf)	14,156.7	14,156.7
Emission Factor (lb/mmscf)	<del>10.86</del> <b>10.29</b>	<del>18.46</del> <b>17.15</b>

**CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)**

The CEC is the lead agency for this project and EME filed an Application for Certification (05-AFC-2) for the project on December 1, 2005. WCEP will be subject to the CEC's 12-month energy facility licensing process which will address public issues and concerns involving zoning, biological resources, water resources, air quality, transmission, public health and safety, and their resolution. The CEC's 12-month licensing process is a certified regulatory program under CEQA and includes several opportunities for public participation. The CEC's license/certification subsumes all requirements of state, local, or regional agencies otherwise required before a new plant is constructed. The CEC coordinates its review of the facility with the federal, state, and local agencies that will be issuing permits to ensure that its certification incorporates the conditions that would be required by these various agencies. The AFC process is the functional equivalent of a traditional CEQA review and will address and resolve issues related to CEQA.

**NSPS for Stationary Gas Turbines – 40CFR Part 60 Subpart GG**

40CFR60 Subpart GG has been superseded by 40CFR60 Subpart KKKK.

Subpart GG applies to the subject turbines because the heat input is greater than 10.14 MMBTU/hour (10.7 gigajoules per hour). (The actual rating is  $891.67 \times 10^6$  BTU/hr \* 1,055 joules/BTU = 940.71 gigajoules/hr). The applicable standards are determined as follows:

For NOx,

$$\text{STD} = 0.0075(14.4/Y) + F$$

where:

Maximum heat input = 891.67 MMBTU/hr

Maximum net output = 104 MW

STD = allowable NOx emissions in percent volume at 15% O<sub>2</sub>, dry basis

Y = manufacturer's rating in KJ/watt-hr

F = 0 for fuel with nitrogen content < 0.015 % weight

0.04 \* %N for 0.015 < %N < 0.1

Therefore,  $Y = 891.67 \text{ MMBTU/hr} / 104 \text{ MW} * 1,055 \text{ joules/BTU} * \text{kJ}/1000\text{j} = 9.045 \text{ KJ/watt-hr}$

For natural gas, nitrogen < 0.015%w, therefore, F=0

$$\text{STD} = 0.0075(14.4/9.045) + 0 = 119 \text{ ppmv NOx}$$

Since the proposed limit of 2.5 ppmv << 119 ppmv, compliance is expected.

For SOx, the limit is a straight 150 ppmv

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SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT  ENGINEERING AND COMPLIANCE DIVISION  ENGINEERING ANALYSIS / EVALUATION	PAGES 64	PAGE 44
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**40CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines**

Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input greater than 10 MMBTU/hr (10.7 gigajoules per hour), based on higher heating value, which commenced construction, modification or reconstruction after February 18, 2005.

§60.4320(a) The turbine is natural gas-fired and has a heat input > 850 MMBTU/hr, therefore, it is subject to a NO<sub>x</sub> emission limit of 15 ppmv @ 15% O<sub>2</sub> from Table 1 of this subpart. The turbine is required to comply with BACT for NO<sub>x</sub> which is officially at 3.5 ppmv at 15% O<sub>2</sub>, dry basis for a simple cycle plant. However, GE has submitted performance warranties which indicate the CTGs will meet a NO<sub>x</sub> level of 2.5 ppmv at 15% O<sub>2</sub> on a 1-hour average which is more stringent than this subpart. Therefore, compliance with this section is expected.

§60.4330(a)(2) Natural gas fuel burned in the turbine has a sulfur content of 0.0006 lb-SO<sub>2</sub>/MMBtu, which is less than 0.06 lb-SO<sub>2</sub>/MMBTU (26 ng-SO<sub>2</sub>/J) required by this section. Therefore, compliance with the sulfur dioxide limits of this section is expected.

§60.4335 The LMS100PA turbines use water injection to help reduce NO<sub>x</sub> to compliance levels. Monitoring is required and will be accomplished with a CEMS; therefore, compliance with this section is expected with a certified CEMS.

§60.4345 The CEMS is required to be certified according to the Performance Specification 2 (PS 2) in appendix B to this part. SCE will be required to file a CEMS application package with Source Test Engineering to certify the CEMS to meet the requirements of Rule 218 or 40CFR60 appendix B. Therefore, compliance with this section is expected.

§60.4400(a) An initial source test will be required per §60.8. The annual source testing requirement for NO<sub>x</sub> will be satisfied through the annual RATAs performed on the CEMS. Compliance with the source testing requirements is expected.

**40CFR63 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. The largest single HAP emission from the is propylene from the turbine at 1.64 TPY. The total combined HAPs from WCEP is less than 3 TPY which is well below the 25 TPY threshold. Therefore, WCEP is not a major source, and the requirements of this regulation do not apply.

**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. The rule is intended to provide reasonable assurance that the control systems are operating properly to maintain compliance with the emission limits. Since WCEP is a major source, then the CAM regulations apply to this facility. The facility will be using CEMS to monitor, report and record both NO<sub>x</sub> and CO emissions continuously downstream of the control equipment which will satisfy the requirements of this regulation.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT  ENGINEERING AND COMPLIANCE DIVISION  ENGINEERING ANALYSIS / EVALUATION	PAGES 64	PAGE 45
	APPLICATION NO. 450894 (Master File)	DATE 2-14-2007
	PROCESSED BY: Ken Coats	REVIEWED BY:

**40CFR Part 72 – Acid Rain Provisions**

WCEP is subject to the requirements of the federal Acid Rain program because the electricity generated will be rated at greater than 25 MW. This program is similar to RECLAIM in that facilities are required to cover SO<sub>2</sub> emissions with SO<sub>2</sub> allowances that are similar in concept to RTC's. SO<sub>2</sub> allowances are however, not required in any year when the unit emits less than 1,000 lbs of SO<sub>2</sub>. Facilities with insufficient allowances are required to purchase SO<sub>2</sub> credits on the open market. In addition, both NO<sub>x</sub> and SO<sub>2</sub> emissions will be monitored and reported directly to USEPA. Based on the above, compliance with this rule is expected.

**REGULATION XXX – Title V**

WCEP is a Title V facility because the cumulative emissions will exceed the Title V major source thresholds and because it is also subject to the federal acid rain provisions. The initial Title V permit will be processed and the required public notice will be sent along with the Rule 212(g) Public Notice, which is also required for this project. EPA is afforded the opportunity to review and comment on the project within a 45-day review period.

**AQMD RESPONSE TO COMMENTS RECEIVED DURING THE RULE 212 & RULE 3006 30 DAY PUBLIC COMMENT PERIOD**

AQMD staff received several comments during the 30-day Public Notice period, which officially ended January 15, 2006. These comments originated from four (4) companies including EME and AQMD's response are contained in the table below.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 46
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

<u>COMMENT</u>	<u>AQMD RESPONSE</u>
<p><u>WCEP Proposes that the initial source test completion date language be changed to state that the initial source test shall occur within 394 operational hours of initial turbine start up. Rather than 180 calendar days from initial turbine start-up, since a total of 394 hours of commissioning activities must be completed before GE will warrant the guarantees for PM10 and VOC. WCEP would only conduct the commissioning during times when the ISO requests plant operation for power generation.</u></p>	<p><u>Although it is typical for new equipment such as the LMS100 CTG to undergo a commissioning period in which the facility follows a systematic approach to optimize performance of the CTGs and their associated equipment, emissions are expected to be greater during this period than during normal operation due to the fact that the APC equipment may only be partially or non-operational during the testing. This is true for NOx and CO emissions. Even though the manufacturer may not specifically warrant emissions of VOC and PM10 to remain within the specified guarantees during the commissioning period, AQMD's past experience has noted that emissions of VOC, SOx and PM10 are not expected to vary to any significant degree to the commissioning of the CTGs. Therefore, AQMD believes that the request to re-word Condition A63.1 to reflect 394 hours of operational hours in lieu of 180 days from initial turbine start-up is not necessary. After in-house discussions, EME elected to withdraw this comment.</u></p>

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 47
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

COMMENT	AQMD RESPONSE
<p>The <u>monthly emission limits for PM10, CO and VOC are based upon fuel use and emission factors that differ slightly from our application. WCEP requests that the monthly emissions for PM10, CO, and VOC be based upon the hourly guaranteed emissions as identified in the Appendix A and specifically Table 8.1A-12 in the application. The Appendix A emission rates are the maximum worst case emissions that could be emitted during facility operations with temperatures ranging from 30 degrees F to 110 degrees F. Based on the worst case operating scenario, WCEP is requesting to set the mass emission limits as follows:</u></p> <p><u>PM10 = 2,776 lb/month;</u>  <u>CO = 6,484 lb/month;</u>  <u>VOC = 1,168 lb/month;</u>  <u>SOx = 287 lb/month.</u></p> <p><u>It appears that the normal operation VOC emission rate was based on 1.71 lb/hr per turbine when the rate should be 2.36 lb/hr per turbine.</u></p>	<p><u>AQMD policy is to base the facility's potential to emit on the worst case scenario, which is the scenario that results in the highest fuel consumption. AQMD has identified GE's 15 possible operating scenarios which were presented in your application. Analysis of these scenarios reveals that GE ran these tests while varying the load, water injection rates, compressor inlet temperature, and ambient temperature. AQMD agrees with WCEP in that the worst case scenario occurs under the conditions defined by operating scenario no. 100. This scenario results in the lowest ambient temperature and the highest fuel consumption, and therefore, the highest possible emission rates. The calculations presented in the analysis are based on the worst case, which is 871.9 MMBTU/hr, which results in monthly emission rates as follows:</u></p> <p><u>PM10 = 2,778 lb/month</u>  <u>CO = 6,532 lb/month</u>  <u>VOC = 1,106 lb/month</u>  <u>SOx = 281 lb/month</u></p> <p><u>As shown in revised Appendix B. VOC emissions were based on BACT level of 2.0 ppmv at a maximum heat rate of 871.9 MMBTU/hr (from operating scenario no. 100) which results in 2.28 lb/hr, and 1,106 lb/month.</u></p>
<p><u>The proposed emission factor used to determine compliance after the CO catalysts are installed and operational is 18.46 lb CO/mmcf. The correct emission factor should be 14 lb CO/mmcf</u></p>	<p><u>AQMD has reviewed the total CO emissions and corresponding fuel consumption during the non-commissioning period in which the APC equipment is assumed to be fully operational. This yields an emission factor of 17.15 lb CO/mmcf as shown in revised Appendix G, which is used during periods when CEMS data is not available. This was discussed and agreed upon by EME.</u></p>
<p><u>CO CEMS data should be used prior to CEMS certification test rather than relying on emission factors and fuel use.</u></p>	<p><u>AQMD policy is to allow facilities to report emissions via CEMS only after the CEMS has been appropriately RATA tested in accordance with the provisions of Rule 218 (CO) and provisionally certified for RECLAIM (NOx), if the facility is or has elected to enter RECLAIM. Since WCEP has elected to enter RECLAIM, each CEMS will need to be provisionally certified for RECLAIM. Therefore, CO emissions will be based on the stated emission factor for CO until which time the CEMS is RATA tested, and NOx emissions prior to provisional certification will be based on the stated emission factor for NOx.</u></p>

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 48
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

COMMENT	AQMD RESPONSE
<p>Condition A63.2 lists the annual emission limits for PM10, CO, SO2, and VOC. As emissions of these pollutants are already limited to monthly emission limits, and in order to be consistent with other SCAQMD permits, WCEP proposes to remove this condition as it is covered under A63.1 monthly emissions.</p>	<p>Condition A63.2 has been removed from the facility permit. However, if the modeling had been based on annual emissions &lt; 12 times the max monthly limits, then condition A63.2 would have remained in the permit.</p>
<p>WCEP proposes to remove the 1-hour start-up time limit, because the initial commissioning phase may include start-up periods which are longer than 1-hour. The emissions of criteria pollutants expected during commissioning were included in the air quality modeling analysis. Further, WCEP proposes to remove the condition limiting start-ups as compliance with the annual NOx limits will be continuously monitored by the NOx CEMS.</p>	<p>AQMD allows a maximum period of 1-hour for start-up of the CTGs in which during this period, the CTGs are allowed to temporarily operate above BACT levels to allow for the SCR and CO catalysts to reach optimal operating temperature. This optimal temperature is necessary for the catalysts to effectively reduce the NOx and CO emissions to their corresponding BACT levels. In the case of the LMS100 CTG, this engine is capable of a relatively quick start-up, usually much less than 1-hour during non-commissioning. However, the CTGs may require longer start-ups during the commissioning phase. Note that sentence 1 of A99.1 and A99.2 excludes the 2 ppmv limit during all phases of commissioning, and start-ups during commissioning may exceed the 1 hour limit. Therefore, there is no need to modify conditions A99.1 or A99.2</p>
<p>WCEP proposes to change the permit language from "initial turbine commissioning" to "prior to the SCR installation" for the 123.46 lb/mmcf NOx emission factor in condition A99.3</p>	<p>Emissions are required to be monitored and reported during all phases of operation, including start-up, shut down, commissioning (1<sup>st</sup> year only) and normal operation. Normally, this is accomplished via CEMS assuming that the CEMS is both operational and certified, otherwise the emissions are determined based on the appropriate emission factor and the corresponding fuel consumption during the period in question. Condition A99.3 addresses the period which occurs from the beginning phase of turbine commissioning and ending with the final phase of turbine commissioning. This period will account for the times in your proposed commissioning schedule during which the SCR may be fully, partially, or completely non-operational. Therefore, the times periods prior to SCR installation are covered in "initial turbine commissioning " Therefore, it is not necessary to reword this condition.</p>

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 49
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

COMMENT	AQMD RESPONSE
The emission factor should be 9 lb/mmcf NOx rather than the 10.86 lb/mmcf as listed in condition A99.4	AQMD has determined that this factor should be 10.29 lb/ mmcf as shown in revised Appendix G.
WCEP proposes to add language that exempts the unit from the 2.5 ppmv NOx, 6.0 ppmv CO and 2.0 ppmv VOC BACT limits during start-up and shutdown.	AQMD concurs with this request and this exemption is already included in conditions A99.1 (NOx) A99.2 (CO) and A99.5 (VOC).
WCEP proposes that the test method for VOC should be listed as modified TO-12. In addition, the requested test method for PM10 is SCAQMD Method 5.1 with averaging time set for four hours.	AQMD concurs with this comment and these requests are covered in condition D29.1. Also note that "District approved averaging time" is the standard language used for the averaging time for PM10.
The NOx RTCs should be set at 29,880 lb per turbine after commissioning. During the commissioning year, the NOx RTC requirement should be set to 41,204 lb per turbine.	AQMD has reviewed this request and has determined that the correct numbers should be 30,222 lb per turbine after commissioning and 38,664 lb per turbine during the commissioning year as shown in revised Appendix F.
WCEP proposes to be exempt from the 5 ppmv NH3 limit during periods of start-up and shut down. Additionally, WCEP proposes that the NOx analyzer be installed and operated within the 394 hour commissioning period rather than 90 days from initial start-up.	Since WCEP will not be injecting ammonia during start-up or shutdown, there is no need to add an exemption for NH3 emissions during this period. Also, WCEP will not be pursuing their request for additional commissioning time. Therefore, the analyzer will be installed and operating within the traditional 90 days from initial start-up.
WCEP proposes to remove the temperature and pressure monitoring requirements since compliance with the 2.5 NOx limitation will be continually monitored by the CEMS.	The purpose of this condition is to have a method of determining compliance with the 2.5 emission limit and to ensure that if the CEMS is inoperable, then the temperature and pressure monitoring devices will ensure the APC equipment is operating properly.
WCEP proposes to replace the totalizing fuel meter with a record of total fuel purchased since Condition D12.5 will record operational hours.	The totalizing fuel meter has been required in the past as a primary means of determining fuel use for the engine, since it cannot operate for more than 199 hours per year. Measuring fuel consumption is another means of determining the total amount of hours the engine has operated. Mere recordkeeping alone may not be enough to establish definitive compliance. Therefore, the totalizing meter requirement cannot be deleted.

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 50
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

COMMENT	AQMD RESPONSE
<p><u>WCEP requests that the condition C1.3 be reworded to exclude a reference to Rule 1110.2 and to include references to Rules 1303 and 1470. WCEP requests that the condition recognize fire pump operations as emergency and not maintenance.</u></p>	<p><u>The correct condition references for this rule are Rule 1304, Rule 1110.2, and Rule 1470. All of these rules are applicable in the form of providing an exemption for this equipment. Rule 1470 provides for certain emissions limits and requirements pertaining to maintenance and testing. Therefore, Rule 1470 is also a correct reference. The purpose of this condition is to provide for the necessary requirements for this engine to operate during an emergency and therefore, the condition properly recognizes the emergency nature of this equipment.</u></p>
<p><u>Hydrogen Ventures, Inc requested AQMD to comment of the discrepancy between GE's claimed cycle efficiency and those cited by both WCEP and SCAQMD. a) Is this discrepancy real, or merely due to differences in methods of calculation and b) whether these differences are significant in determining conditions for both permit and requirements for emissions credits.</u></p>	<p><u>It appears that the efficiencies cited are representative of the thermal efficiency of the Brayton Cycle (overall plant efficiency) and are not representative of the reduction efficiency of the SCR and CO catalyst. NOx &amp; CO emissions are determined by the reduction efficiency of the SCR system.</u></p>
<p><u>Were the potential air quality benefits of the LMS100 STIG configuration factored into AQMD's evaluation of the WCEP permit?</u></p>	<p><u>The WCEP CTGs are equipped with water injection and configured to include an SCR/CO catalyst to further reduce the NOx &amp; CO emissions by 90%. At this rate, the project will exceed current BACT levels for NOx and CO, satisfying AQMD's NSR requirements. The applicant further looked at including different technologies in conjunction with the present configuration and concluded that the additional technologies were not available or would not further reduce emissions beyond current levels of 2.5 ppmv for NOx or 6 ppmv for CO. Therefore, the additional technologies were eliminated from the design.</u></p>

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 51
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

COMMENT	AQMD RESPONSE
<u>Rule 1303(b) (2) seems to require offsets for the ammonia emissions even though BACT is met. Please comment.</u>	<u>NH3 is not considered to be a non-attainment air contaminant as defined in Regulation XIII. However, Rule 1303(a) (1) requires BACT for non-attainment pollutants, ozone depleting compounds (ODC's) and NH3. The rule language in Rule 1303(a) (1) distinguishes between non-attainment pollutants and NH3 and the language in Rule 1303(b) (2) is silent on NH3. Therefore, the rule language of Rule 1303(a) (1) and 1303(b) (2) imply that NH3 is not a non-attainment pollutant and as such offsets for NH3 are not required.</u>
<u>Hydrogen Ventures, Inc, requests AQMD to comment on why NH3 emissions are not factored into determination of PM2.5 emissions from the proposed project</u>	<u>The engineering analysis for WCEP quantifies PM10 emissions from each CTG and all PM10 emissions are required to be offset in accordance with Rule 1303(b) (2). PM2.5 is essentially a subset of PM10 and is therefore also subject to Regulation XIII. Compliance with PM10 emission limits will be based on AQMD Test Methods which includes both front half and back half. The back half includes condensibles which typically consist of ammonia salts. Therefore, ammonia is considered in PM10 and PM2.5 determinations.</u>
<u>Perrin Manufacturing, Inc. objects to the issuance by the AQMD for a Permit to Operate the site without the benefit of an environmental impact study being performed which will explicitly address the issue of air quality. An environmental impact report is appropriate and needed.</u>	<u>This project is required to undergo a environmental review by and to obtain a license from the California Energy Commission (CEC) due to the fact that it is rated at greater than 50 MW. The CEC's 12-month licensing process is a certified regulatory program under CEQA and includes several opportunities for public participation. The CEC's license/certification subsumes all requirements of state, local, or regional agencies otherwise required before a new plant is constructed. The CEC coordinates its review of the facility with the federal, state, and local agencies that will be issuing permits to ensure that its certification incorporates the conditions that would be required by these various agencies. The AFC process is the functional equivalent of a traditional CEQA review and will address and resolve issues related to CEQA. It is the functional equivalent of an environmental impact report.</u>

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 52
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**OVERALL EVALUATION / RECOMMENDATION(S)**

Issue a Facility Permit to Construct with the following permit conditions.

**PERMIT CONDITIONS**

(LMS100PA CTGs) Devices D1, D7, D13, D19, D25

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

CONTAMINANT	EMISSION LIMIT
PM <sub>10</sub>	<del>2,722</del> 2,778 LBS IN ANY ONE MONTH
CO	<del>6,772</del> 6,532 LBS IN ANY ONE MONTH
SOx	281 LBS IN ANY ONE MONTH
VOC	<del>919</del> 1,106 LBS IN ANY ONE MONTH

The operator shall calculate the monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors: VOC: 2.00 lb/mmcf; PM10: 6.93 lb/mmcf; and SOx: 0.71 lb/mmcf.

Monthly Emissions, lb/month = X (E.F.)

Where X = monthly fuel usage in mmcf/month and E.F. = emission factor indicated above.

Compliance with the CO emission limit shall be verified through valid CEMS data.

The operator shall calculate the emission limit(s) for the purpose of determining compliance with the monthly CO limit in the absence of valid CEMS data by using the above equation and the following emission factor(s):

- (A) During the commissioning period and prior to CO catalyst installation - 125.87 lbs CO/mmcf
- (B) After installation of the CO catalyst but prior to CO CEMS certification testing - ~~18.46~~ 17.15 lb CO/mmcf. The emission rate shall be recalculated in accordance with Condition D82.1 if the approved CEMS certification test resulted in emission concentration higher than 6 ppmv.
- (C) After CO CEMS certification testing - ~~18.46~~ 17.15 lb/CO mmcf. After CO CEMS certification test is approved by the AQMD, the emissions monitored by the CEMS and calculated in accordance with condition 82.1 shall be used to calculate emissions.

For the purposes of this condition, the limit(s) shall be based on the emissions from a single turbine. During commissioning, the CO emissions shall not exceed ~~7,691~~ 7,441 lbs in any one month. During commissioning, the VOC emissions shall not exceed ~~935~~ 1,114 lbs in any one month.

The operator shall provide the AQMD with written notification of the date of initial CO catalyst use within seven (7) days of this event.  
[Rule 1303 - Offsets]

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 53
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

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

CONTAMINANT	EMISSION LIMIT
PM <sub>10</sub>	<del>20,392 LBS IN ANY ONE YEAR</del>
CO	<del>52,256 LBS IN ANY ONE YEAR</del>
SO <sub>x</sub>	<del>2,102 LBS IN ANY ONE YEAR</del>
VOC	<del>7,043 LBS IN ANY ONE YEAR</del>

~~The operator shall calculate the monthly emissions for VOC, PM10 and SO<sub>x</sub> using the equation below and the following emission factors: VOC: 2.00 lb/mmef; PM10: 6.93 lb/mmef; and SO<sub>x</sub>: 0.71 lb/mmef.~~

~~Monthly Emissions, lb/month = X (E.F.)~~

~~Where X = monthly fuel usage in mmef/month and E.F. = emission factor indicated above.~~

~~Compliance with the CO emission limit shall be verified through valid CEMS data.~~

~~The operator shall calculate the emission limit(s) for the purpose of determining compliance with the monthly CO limit in the absence of valid CEMS data by using the above equation and the following emission factor(s):~~

~~(D) During the commissioning period and prior to CO catalyst installation 125.87 lbs CO/mmef~~

~~(E) After installation of the CO catalyst but prior to CO CEMS certification testing 18.46 lb CO/mmef. The emission rate shall be recalculated in accordance with Condition D82.1 if the approved CEMS certification test resulted in emission concentration higher than 6 ppmv.~~

~~(F) After CO CEMS certification testing 18.46 lb/CO mmef. After CO CEMS certification test is approved by the AQMD, the emissions monitored by the CEMS and calculated in accordance with condition 82.1 shall be used to calculate emissions.~~

~~For the purposes of this condition, the limit(s) shall be based on the emissions from a single turbine. During commissioning, the CO emissions shall not exceed 60,376 lbs in any one year. During commissioning, the VOC emissions shall not exceed 7,191 lbs in any one year.~~

~~The operator shall provide the AQMD with written notification of the date of initial CO catalyst use within seven (7) days of this event.~~

~~For the purpose of this condition, the yearly emission limit shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12 month period beginning on the first day of each calendar month.  
{Rule 1303-Offsets}~~

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 54
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

- A99.1 The 2.5 PPM NOx emission limits shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 134 hours. Start-up time shall not exceed 60 minutes for each start-up, excluding start-ups during the commissioning period. Shutdown periods shall not exceed 10 minutes for each shutdown. The turbine shall be limited to a maximum of 350 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.  
[Rule 2005]
- A99.2 The 6.0 PPM CO emission limits shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 134 hours. Start-up time shall not exceed 60 minutes for each start-up, excluding start-ups during the commissioning period. Shutdown periods shall not exceed 10 minutes for each shutdown. The turbine shall be limited to a maximum of 350 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.  
[Rule 1303(a) - BACT, Rule 1303(b)(1) - Modeling, Rule 1303(b)(2) - Offsets]
- A99.3 The 123.46 LBS/MMCF NOx emission limits shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.  
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]
- A99.4 The ~~10.96~~ 10.29 LBS/MMCF NOx emission limits shall only apply during the interim reporting period after initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.  
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]
- A99.5 The 2.0 PPM VOC emission limit shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 134 hours. Start-up time shall not exceed 60 minutes for each start-up, excluding start-ups during the commissioning period. Shutdown periods shall not exceed 10 minutes for each shutdown. The turbine shall be limited to a maximum of 350 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.  
[Rule 1303(a) - BACT, Rule 1303(b)(1) - Modeling, Rule 1303(b)(2) - Offsets]
- A195.1 The 6.0 PPMV CO 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]
- A195.2 The 2.5 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.  
[Rule 2005]
- A193.3 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]

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<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 55
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

C1.1 The operator shall limit the fuel usage to no more than 393 mmcf in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single turbine.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition.

*[Rule 1303(b) (2) - Offset]*

D12.1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the turbine.

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

*[Rule 1303(b) (2) - Offset, Rule 2012]*

D29.1 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	Approved District method	District approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District method	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.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 56
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

The test shall be conducted when this equipment is operating at maximum, average, and minimum loads.

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 2005]*

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
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 BACT concentration limit  
*[Rule 1303(a)(1) - BACT]*



<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 57
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

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
SOX emissions	Approved District method	District approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District method	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 maximum, average, and minimum 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]

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 58
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

D82.1 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis

The CEMS shall be installed and operated no later than 90 days after initial start-up of the turbine, and in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. Within two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

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

The CEMS would 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 =  $K C_{co} F_d [20.9 / (20.9\% - \%O_2 d)] [(Q_g * HHV) / 106]$ , where

$K = 7.267 * 10^{-8}$  (lb/scf)/ppm

$C_{co}$  = Average of four consecutive 15 min. ave. CO concentration, ppm

$F_d$  = 8710 dscf/MMBTU natural gas

$\%O_2 d$  = Hourly ave. % by vol.  $O_2$  dry, corresponding to  $C_{co}$

$Q_g$  = Fuel gas usage during the hour, scf/hr

HHV = Gross high heating value of fuel gas, BTU/scf

[Rule 1303(a)(1) - BACT, Rule 218]

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 start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start up of the turbine.

[Rule 2005; Rule 2012]

E193.1 The operator shall upon completion of 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 05-AFC-2 project.

[CEQA]

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 59
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

I296.1 This equipment shall not be operated unless the operator demonstrates 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 after the first 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 prior to the 1<sup>st</sup> compliance year hold a minimum NOx RTCs of 38,664 lbs/yr. This condition shall apply during the 1<sup>st</sup> 12 months of operation, commencing with the initial operation of the gas turbine.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the 1<sup>st</sup> compliance year, hold a minimum of 30,222 ~~29,122~~ lbs/yr of NOx RTCs for operation of the gas turbine. In accordance with Rule 2005(f), unused RTC's may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1<sup>st</sup> compliance year.

This condition shall apply to each turbine individually.  
 [Rule 2005]

K40.1 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 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 (DACFM).

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, Rule 2005]

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

Natural gas fuel use after CEMS certification  
 Natural gas fuel use during the commissioning period  
 Natural gas fuel use after the commissioning period and prior to CEMS certification

[Rule 2012]

**(SCR/CO Catalyst)**

A195.4 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:

$$\text{NH3 (ppmv)} = [a - b * c / 1\text{EE} + 06] * 1\text{EE} + 06 / b$$

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> <b>64</b>	<b>PAGE</b> <b>60</b>
	<b>APPLICATION NO.</b> <b>450894 (Master File)</b>	<b>DATE</b> <b>2-14-2007</b>
	<b>PROCESSED BY:</b> <b>Ken Coats</b>	<b>REVIEWED BY:</b>

where,

a = NH<sub>3</sub> 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 NO<sub>x</sub> across the SCR (ppmv at 15% O<sub>2</sub>)

The operator shall install and maintain a NO<sub>x</sub> analyzer to measure the SCR inlet NO<sub>x</sub> ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NO<sub>x</sub> 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, Rule 2012]

D12.2 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.

[Rule 1303(a)(1) - BACT, Rule 2005]

D12.3 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.

[Rule 1303(a)(1) - BACT, Rule 2005]

D12.4 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.

[Rule 1303(a)(1) - BACT, Rule 2005]

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 D12.2

Condition Number D12.3

[Rule 1303(a)(1) - BACT]

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 61
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

E179.2 For the purpose of the following condition numbers, continuously record 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: D12.4  
[Rule 1303(a)(1) - BACT]

E193.1 The operator shall upon completion of 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 05-AFC-2 project.  
[CEQA]

**(Ammonia Storage Tank)**

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

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]

E193.1 The operator shall upon completion of 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 05-AFC-2 project.  
[CEQA]

**(Emergency Fire Pump)**

C1.3 The operator shall limit the operating time to no more than 199.99 hours in any one year.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing  
[Rule 1110.2, Rule 1304, Rule 2012]

D12.5 The operator shall install and maintain a(n) non-resettable elapsed meter to accurately indicate the elapsed operating time of the engine.  
[Rule 1304, Rule 1470, Rule 2012]

D12.6 The operator shall install and maintain a(n) non-resettable totalizing fuel meter to accurately indicate the fuel usage of the engine.  
[Rule 1304, Rule 2012]

B61.1 The operator shall only use diesel fuel containing the following specified compounds:

COMPOUND	Range	PPM BY WEIGHT
Sulfur	Less than or equal to	15

[Rule 431.2]

E193.2 The operator shall operate and maintain this equipment according to the following requirements:

NOTE: Changes to the PDOC issued October 31, 2006 are denoted by underlined additions and ~~strikethrough~~ deletions

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 62
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

1. This equipment shall only operate if utility electricity is not available.
2. This equipment shall only be operated for the primary purpose of providing a backup source of power to drive an emergency fire pump.
3. This equipment shall only be operated for maintenance and testing, not to exceed 50 hours in any one year.
4. This equipment shall only be operated under limited circumstances under a Demand Response Program (DRP).
5. An engine operating log shall be kept in writing, listing the date of operation, the elapsed time, in hours, and the reason for operation. The log shall be maintained for a minimum of 5 years and made available to AQMD personnel upon request.

[Rule 1470, Rule 1110.2]

I296.2 This equipment shall not be operated unless the operator demonstrates to the Executive Officer 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 after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall, prior to each compliance year hold a minimum NOx RTCs of ~~1,851~~ 2,097 lbs.

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 1<sup>st</sup> compliance year.

[Rule 2005]

K67.2 The operator shall keep records in a manner approved by the Executive Officer, for the following parameter(s) or item(s):

Date of operation, the elapsed time, in hours, and the reason for operation  
[Rule 1110.2]

**(Section D; Device E32)**

K67.3 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 63
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

<b>SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT</b>  <b>ENGINEERING AND COMPLIANCE DIVISION</b>  <b>ENGINEERING ANALYSIS / EVALUATION</b>	<b>PAGES</b> 64	<b>PAGE</b> 64
	<b>APPLICATION NO.</b> 450894 (Master File)	<b>DATE</b> 2-14-2007
	<b>PROCESSED BY:</b> Ken Coats	<b>REVIEWED BY:</b>

**WALNUT CREEK ENERGY PROJECT**  
**List of Appendices**

1. Appendix A - LMS100PA Hourly Emissions
  - Normal Operations
  - Start-up Emissions
  - Shutdown Emissions
2. Appendix B - LMS100PA Monthly Emissions
  - Commissioning year
  - Non-Commissioning year
  - 30-Day Averages (Commissioning year)
  - 30-Day Averages (Non-commissioning year)
3. Appendix C - LMS100PA Annual Emissions
  - Commissioning year
  - Non-commissioning year
4. Appendix D - Emergency Fire Pump Emissions
5. Appendix E - Cooling Tower Emissions
6. Appendix F - NOx RTC calculations
7. Appendix G - Interim Period Emission Factors