SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 52	PAGE 1
ENGINEERING AND COMPLIANCE DIVISION	APPLICATION NO. 450894 (Master File)	DATE 3-11-2011
ENGINEERING ANALYSIS / EVALUATION	PROCESSED BY: Ken Coats	REVIEWED BY:

REVISED DETERMINATION OF COMPLIANCE
WALNUT CREEK ENERGY, LLC

COMPANY NAME AND ADDRESS
Walnut Creek Energy, LLC
% Edison Mission Energy
3 MacArthur Place
Santa Ana, CA 92707
Contact: Ms. Jenifer Morris Lee
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
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
GAS TURBINE, UNIT NO. 1, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, INTERCOOLED, 891.7 MMBTU/HR AT 30 DEGREES F WITH WATER INJECTION, WITH A/N 450894 GENERATOR, 100.1 net MW (104 gross MW)	D1	C3	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO:** 4.0 PPMV NATURAL GAS (4) [Rule 1703(a)(2)–PSD-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK]; **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.73 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT; Rule 1703(a)(2)-PSD-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**: 0.06 LB/MMBTU (8) [40 CFR60 Subpart KKKK]; **SOX:** 0.67 LB/MMCF NATURAL GAS (1) [Rule 2011]; **SO2**: (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, C1.4, D12.1, D12.7, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, E193.3 I296.1, I296.3 K40.1, K67.1

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
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, INTERCOOLED, 891.7 MMBTU/HR AT 30 DEGREES F WITH WATER INJECTION, WITH A/N 450895 GENERATOR, 100.1 net MW (104 gross MW)	D7	C9	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO:** 4.0 PPMV NATURAL GAS (4) [Rule 1703(a)(2)–PSD-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK]; **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.73 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT; Rule 1703(a)(2)-PSD-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**: 0.06 LB/MMBTU (8) [40 CFR60 Subpart KKKK]; **SOX:** 0.67 LB/MMCF (1) NATURAL GAS [Rule 2011] **SO2**: (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, C1.4, D12.1, D12.7, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, E193.3 I296.1, I296.3 K40.1, K67.1

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 2, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450900	C9	D7 C10			
SELECTIVE CATALYTIC REDUCTION NO. 2, 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: 450900	C10	S12 C9		**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. 2, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450895	S12	C10			
GAS TURBINE, UNIT NO. 3, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, INTERCOOLED, 891.7 MMBTU/HR AT 30 DEGREES F WITH WATER INJECTION, WITH A/N 450896 GENERATOR, 100.1 net MW (104 gross MW)	D13	C15	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO:** 4.0 PPMV NATURAL GAS (4) [Rule 1703(a)(2)–PSD-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK]; **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.73 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT; Rule 1703(a)(2)-PSD-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**: 0.06 LB/MMBTU (8) [40 CFR60 Subpart KKKK]; **SOX:** 0.67 LB/MMCF (1) NATURAL GAS [Rule 2011] **SO2**: (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, C1.4, D12.1, D12.7, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, E193.3 I296.1, I296.3 K40.1, K67.1

Equipment Description (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 3, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450901	C15	D13 C16			
SELECTIVE CATALYTIC REDUCTION NO. 3, 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: 450901	C16	S18 C15		**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. 3, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450896	S18	C16			
GAS TURBINE, UNIT NO. 4, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, INTERCOOLED, 891.7 MMBTU/HR AT 30 DEGREES F, WITH WATER INJECTION, WITH A/N 450897 GENERATOR, 100.1 net MW (104 gross MW)	D19	C21	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO:** 4.0 PPMV NATURAL GAS (4) [Rule 1703(a)(2)–PSD-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK]; **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.73 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT; Rule 1703(a)(2)-PSD-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**: 0.06 LB/MMBTU (8) [40 CFR60 Subpart KKKK]; **SOX:** 0.67 LB/MMCF (1) NATURAL GAS [Rule 2011] **SO2**: (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, 195.3, A327.1, C1.1, C1.4, D12.1, D12.7, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, E193.3 I296.1, I296.3 K40.1, K67.1

Equipment Description (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 4, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450904	C21	D19 C22			
SELECTIVE CATALYTIC REDUCTION NO. 4, 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: 450904	C22	S24 C21		**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. 4, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450897	S24	C22			
GAS TURBINE, UNIT NO. 5, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, INTERCOOLED, 891.7 MMBTU/HR AT 30 DEGREES F WITH WATER INJECTION, WITH A/N 450898 GENERATOR, 100.1 net MW (104 gross MW)	D25	C27	NOX: MAJOR SOURCE SOX: PROCESS UNIT	**CO:** 4.0 PPMV NATURAL GAS (4) [Rule 1703(a)(2)–PSD-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK]; **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.73 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT; Rule 1703(a)(2)-PSD-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**: 0.06 LB/MMBTU (8) [40 CFR60 Subpart KKKK]; **SOX:** 0.67 LB/MMCF (1) NATURAL GAS [Rule 2011] **SO2**: (9) Acid Rain Provisions	A63.1, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, C1.4, D12.1, D12.7, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, E193.3 I296.1, I296.3 K40.1, K67.1

Equipment Description (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
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			
System 2: EMERGENCY FIRE PUMP					
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE, DIESEL FUEL, LEAN BURN, CLARKE, MODEL JU6H-UFAD58, 183 BHP WITH AFTERCOOLER, TURBOCHARGER, A/N: 450908	D34		NOX: PROCESS UNIT SOX: PROCESS UNIT	**NOX+NMHC:** 2.80 GM/BHP-HR DIESEL RULE 2005; Rule 1703(a)(2)-PSD-BACT]; **NOX:** 469 LB/1000 GAL DIESEL (1) [RULE 2012] **CO:** 0.90 GM/BHP-HR DIESEL (4) [Rule 1703(a)(2)-PSD-BACT] **PM10:** 0.10 GM/BHP-HR DIESEL (4) [Rule 1303-BACT] **SOX:** 0.0041 GM/BHP-HR DIESEL (4) [RULE 2005-BACT; RULE 1703(a)(2)-PSD-BACT]; **SOX:** 0.103 LB/1000 GAL DIESEL (1) [Rule 2011]	C1.3, B61.1, D12.5, D12.6, E193.1, E193.2, I296.2, K67.2
Process 2: INORGANIC CHEMICAL STORAGE					
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

Section D of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE SPECIFIC RULES					
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

Walnut Creek Energy, LLC (WCE), a Delaware limited liability company, is proposing to develop, own, and operate the proposed natural gas fired peaker project known as Walnut Creek Energy Park (WCEP). WCE will be a wholly-owned subsidiary of Edison Mission Walnut Creek, Inc. (EMWC), which will be a wholly-owned or majority-owned subsidiary of Edison Mission Energy (EME). Edison Mission Walnut Creek, Inc. will also wholly-own Edison Mission Huntington Beach, LLC (EMHB), a limited liability corporation which will, after obtaining the appropriate regulatory approvals from FERC, CAISO, and if required, CPUC, finalize the purchase of AES Huntington Beach electric utility boilers and steam turbine generators Units 3 and 4 from AES Huntington Beach, LLC (AQMD ID No. 115389) located at 21730 Newland Street Huntington Beach, CA 92646. Edison Mission Huntington Beach will then retire its Huntington Beach Units 3 and 4 prior to start up of the WCEP.

WCE is proposing to construct a new power plant which will consist of five (5) combustion-turbine-generators (CTGs) for a total rated peak gross generating capacity of 520 MW at 30°F (or a maximum rated net generation capacity of 500.5 MW at the proposed location). The gas turbines will be General Electric LMS100 units. Each turbine will drive a generator rated at 104 MW at 30°F. The project is expected to have an annual capacity factor of approximately 14 to 40 percent, but in extreme conditions up to 46 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, with 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, CO, and a small portion of VOC emissions. One 16,000 gallon ammonia (NH_3) 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 183 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 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 with the exception of federal permitting requirements for New Source Review program for Prevention of Significant Deterioration and the federal operating permit program known as Title V program, which incorporates the Permit to Construct, assigned to AQMD under applicable law and delegation agreement.

The CEC coordinates its review of the facility with the other agencies that will be issuing permits to ensure that the CEC certification incorporates conditions of certification that would be required by various other agencies. Since the WCEP will be rated at greater than 50 megawatts, it is subject to the CEC's 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, WCE submitted Title V 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

All of the applications were submitted to the AQMD on November 30, 2005, except for the application for the NH_3 storage tank, which was submitted on December 7, 2005. AQMD deemed the applications complete on December 13, 2005. In addition to being a federal major source (due to having a potential to emit NOx in an amount greater than 10 tons per year), WCEP will have the potential to generate electricity greater than 25 MW. As a result, WCEP will be subject to the federal Acid Rain requirements as well as federal Title V permitting requirements. Based on a request from WCE to opt into RECLAIM, WCEP will also be included in both the NOx and SOx RECLAIM programs.

The Preliminary Determination of Compliance (PDOC) for the WCEP was issued on October 31, 2006. At the time of issuance of the PDOC, WCE had proposed to offset the WCEP emissions through the use of Emission Reduction Credits (ERCs), RECLAIM Trading Credits and by accessing Priority Reserve Credits pursuant to AQMD Rule 1309.1, as amended on September 8, 2006, or a combination of these offset strategies. The Public Notice was published in the newspaper of general circulation in the county where this facility is located. 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 CEC, EPA, ARB, Federal Land manager, State Land Manager, SCAG, and the City Manager of the City of Industry, along with a copy to the applicant on November 15, 2006. 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 WCE 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. 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. The comments and responses for the notice published in November 2006 are summarized in Appendix H. The FDOC was issued by AQMD on February 16, 2007.

Since the issuance of the FDOC, EPA has published in the Federal Register their final decision to approve AQMD's request to re-designate South Coast Air Basin from Non-Attainment to Attainment for Carbon Monoxide National Ambient Air Quality Standard. EPA has published their proposed decision in the Federal Register on February 24, 2007 and the comment period closed on March 16, 2007 with no comments received by EPA. Therefore, EPA has granted the State's request to re-designate South Coast as attainment for CO effective June 11, 2007. As a result of this re-designation, and pursuant to Rule 1303(b) there will be no offset required for emission increases of Carbon Monoxide for permits issued on or after June 11, 2007. In addition, on August 3, 2007, the AQMD Governing Board amended Rule 1309.1 to replace the September 8, 2006 amendments to include several new requirements for power plants. Furthermore, on August 15, 2007, EPA and AQMD signed a Partial PSD Delegation Agreement, which is intended to delegate the authority and responsibility to AQMD for issuance of initial PSD permits and PSD permit modifications. (The PSD requirements for WCEP are shown in greater detail in the Regulation XVII PSD Analysis below).

Since the requirements of Rule 1309.1 as amended on August 3, 2007 had changed significantly since WCEP originally requested access to the Priority Reserve pursuant to the September 8, 2006 amendments to Rule 1309.1, it was determined by AQMD that a new 30-day Public Notice period pursuant to Rule 212(g) and Rule 3006(a) as well as a 45-day EPA review period were required to address the new requirements in the August 3, 2007 version of Rule 1309.1, prior to finalizing the issuance of the AQMD permits to construct. A draft Amendment to the Determinations of Compliance was prepared on January 11, 2008. The Public Notice was published in the newspaper of general circulation in the county where this facility is located. The Public Notice, engineering analysis and draft permit were submitted to the CEC, EPA, ARB, Federal Land Manager, State Land Manager, SCAG, and the manager of the City of Industry, along with a copy to the applicant on January 11, 2008. The applicant distributed copies of the Public Notice to each address within a ¼ mile radius of the project on January 15, 2008, and provided proof of such distribution in a February 14, 2008 letter from WCE to AQMD 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. The Public notice period ended on February 20, 2008, with no comments received from the public. However, comments were received from the EPA and WCE. The comments and responses for the notice published in January 2008 are summarized in Appendix I. An amended FDOC was issued by AQMD on February 22, 2008 in which WCE was informed that they must comply with the additional requirements of Rule 1309.1 prior to AQMD releasing Priority Reserve Credits and issuance of the Title V Permit. CEC then issued a license to WCEP on February 27, 2008.

On May 16, 2008 the USEPA released its final NSR rule for PM2.5 and published it in the Federal Register. The effective date of the Final NSR Rule for PM2.5 was July 15, 2008. The Final Rule specifies that for areas which are non-attainment for PM2.5 NAAQS, the state and local agencies must adopt and submit non-attainment NSR rules to implement the PM2.5 requirements for EPA's approval into the State Implementation Plan no later than July 11, 2011. Since this project is located in the South Coast Air Basin that is designated as non-attainment for PM2.5 and the AQMD has not yet adopted PM2.5 NSR rules, the requirements of NSR for PM2.5 must be implemented through Appendix S. Thus, as of July 15, 2008 all AQMD permit applications for facilities with PM2.5 emissions must be evaluated for compliance with PM2.5 requirements that are included in Appendix S. In a letter dated July 29, 2008, AQMD informed WCE that as of July 15, 2008, all AQMD permit applications for facilities with PM2.5 emissions must be evaluated for compliance with PM2.5 requirements that are included in Appendix S to Part 51 of Title 40 of the Code of Federal Regulations. In addition to the issue of PM2.5 requirements, AQMD informed WCE in a letter dated February 26, 2009 that AQMD Rule 1309.1-Priority Reserve, as amended on August 3, 2007 had been invalidated by court order in July and November 2008, and that in the absence of amended Rule 1309.1, WCE was required to provide emission offsets in the form of Emission Reduction Credits (ERCs) in order to demonstrate that WCEP will comply with the emission offset requirements of AQMD Rule 1303(b).

In a letter dated March 3, 2011, WCE informed AQMD of their intent to pursue a new offset strategy and requested AQMD to issue a revision to the FDOC for WCEP. To comply with the offset requirements for WCEP, Edison Mission Huntington Beach, LLC, an affiliate of WCE under common ownership of Edison Mission Walnut Creek, Inc., which will be a wholly-owned or majority-owned subsidiary of EME, will be formed to purchase two electric utility steam boilers and their associated steam turbine generators (STGs) from AES Huntington Beach, LLC (AESHB) and will permanently retire these units in accordance with the requirements of AQMD Rule 1304(a)(2) to qualify for a partial offset exemption on a net megawatt to net megawatt basis. Any emissions not fully offset by the provisions of Rule 1304(a)(2) will be offset with ERCs. However, only Non-RECLAIM pollutants may qualify for the Rule 1304(a)(2) provision, which includes PM10, CO, and VOC. WCEP has requested to opt into and will be included in the RECLAIM program for both NOx and SOx and therefore will purchase sufficient RECLAIM Trading Credits (RTCs) to comply with the offset requirements of Rule 2005. The two boilers and steam turbines to be purchased by EMHB are AESHB's Units 3 and 4 (ID D98 & D104), which are currently in operation at AESHB's Huntington Beach facility (Facility ID # 115389). The two units (HB 3 and 4) will be leased back to AESHB who will remain as the operator until the required permanent shutdown.

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. Although EME through EMWC and EMHB will own Huntington Beach Units 3 and 4, since the sale is not yet finalized, the compliance record for Units 3 and 4 under EME's, the parent company of EMWC and EMHB, ownership does not exist yet.

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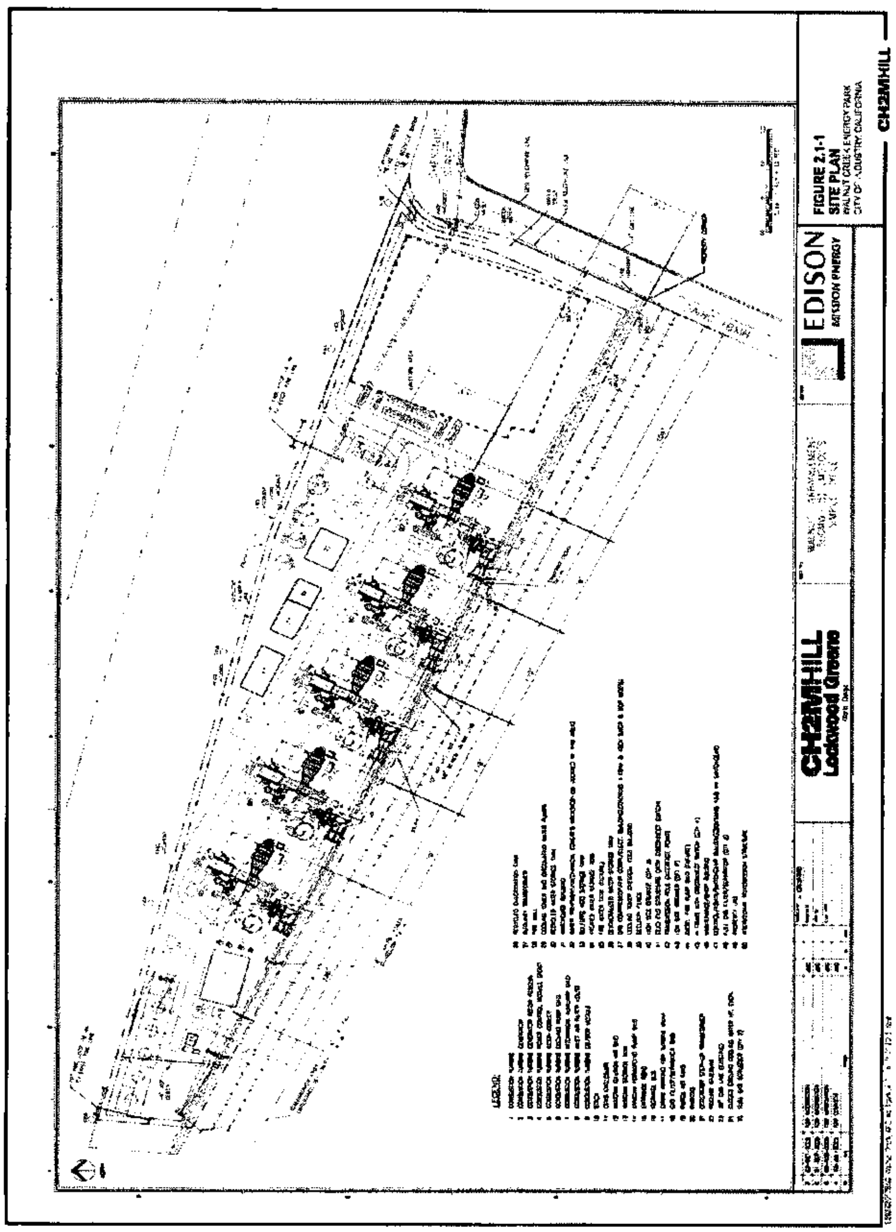
ENGINEERING AND COMPLIANCE DIVISION	APPLICATION NO. 450894 (Master File)	DATE 3-11-2011
ENGINEERING ANALYSIS / EVALUATION	PROCESSED BY: Ken Coats	REVIEWED BY:

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 was previously entirely covered with a large warehouse building and asphalt paving, which have been removed, and the parcel is now vacant. Walnut Creek Energy, LLC has leased the site from the Development Agency. WCEP will be located in an area zoned for industrial uses. 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.



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 site plan shown on the previous page 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. Residential areas are located in the City of La Puente to the north, beyond the intermodal terminal and in unincorporated areas of the Los Angeles County community of Hacienda Heights to the south.

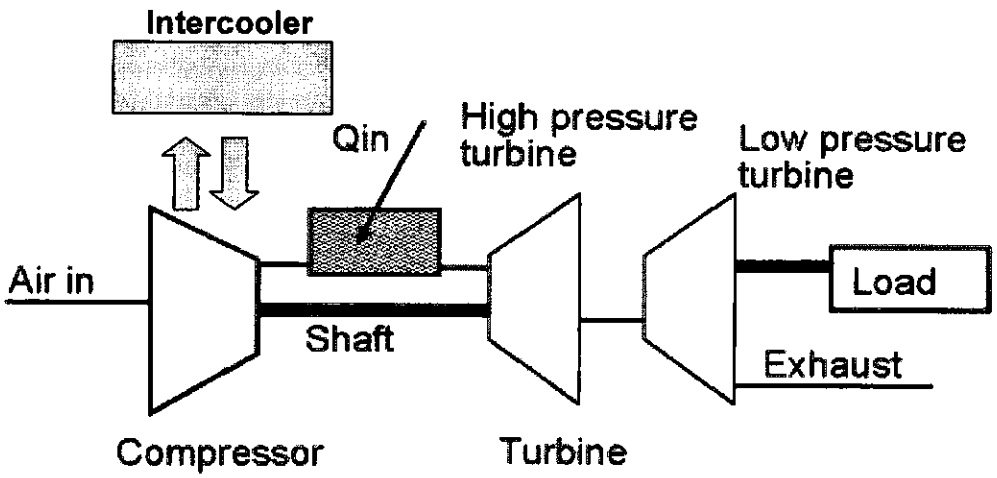
PROCESS DESCRIPTION

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.

LMS100 Gas Turbine with Intercooler



The following table lists the technical specifications for the General Electric LMS100 CTG.

Table 2 – Combustion Turbine Generator Specifications[1]

Parameter	Specifications
Manufacturer	General Electric
Model	LMS100PA[2]
Fuel Type	PUC[3] Quality Natural Gas
Natural Gas Heating Value	1,050 BTU/scf
Gas Turbine Heat Input (HHV)	891.7 MMBTU/hr at 30 °F and 60% relative humidity
Fuel Consumption	0.861 MMSCF/hr[4]
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

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 4,000

[1] Values in this table are on a per-turbine basis

[2] 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.

[3] PUC is the acronym for the California Public Utilities Commission

[4] 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.

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 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 de-mineralized water for water injection directly into the CTGs. The de-mineralized water will be produced by reverse osmosis (RO) and an ion exchange system and will be stored in a 100,000 gallon de-mineralized water storage tank. The use of de-mineralized water injection will reduce the 1-hour average NOx concentration to 25 ppmv on a dry basis at 15% O_2 prior to entry to the selective catalytic reduction (SCR) units. 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_2. CO emissions will be limited to 4.0 ppmv, 1-hour average, dry basis, at 15% O_2. ROG emissions will be limited to 2.0 ppmv, dry basis at 15% O_2. SOx and PM_{10} emissions will be minimized 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

Table 3 below shows the specifications for the SCR to be used for the simple cycle CTGs.

Table 3 – 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^3
Guaranteed Life	Earliest of 20,000 hrs from first gas-in or 51 months from contracted delivery.
Space Velocity	23,580 hr^{-1}
Ammonia Injection Rate	190 lb/hr
NOx removal efficiency	>90%
NOx at stack outlet	2.5 ppmv at 15% O_2
Exhaust Temperature	715-817 °F

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_2) and water, resulting in NOx concentrations in the exhaust gas at no greater than 2.5 ppmvd at 15% O_2 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 4.0 ppmvd at 15% O_2, 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 4 below shows the specifications for the CO Oxidation Catalyst to be used for the simple cycle CTGs.

Table 4 – 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^{-1}
Volume	200 ft^3
CO removal efficiency	90%
CO at stack outlet	4.0 ppmvd at 15% O_2
Exhaust gas velocity	24 ft/s

Aqueous Ammonia Storage Tank

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.

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[5] 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_2. The table below shows the warranted emissions for NOx, CO, VOC and NH_3 slip.

Table 5 - Warranted Emissions for APC System

Pollutant	Warranted Emissions
Outlet NOx emissions	2.5 ppmv at 15% O_2, dry basis
Outlet CO emissions	4.0 ppmv at 15% O_2, dry basis
Outlet VOC emissions	2.0 ppmv at 15% O_2, dry basis
Ammonia Slip	5.0 ppmv at 15% O_2, 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_{10} 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_{10}. The rate of PM_{10} 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 the Table 6 below.

Table 6 - 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%

[5] 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_2. Therefore, uncontrolled VOC emissions are assumed to be 4.0 ppmvd at 15% O_2, dry basis.

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 7 - 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
Fan Exit Height (ft AGL)	39.09

Emergency Fire Pump Engine

The fire pump engine will be a diesel fueled Clarke unit, model no. JU6H-UFA58. It has a power rating of 183 bhp at 1,760 rpm. The specifications are listed in the table below.

Table 8 - Emergency Fire Pump Specifications

Emergency Fire Pump Parameters	Specifications
Manufacturer	Clarke
Model No. / Tier No.	JU6H-UFAD58 / EPA Tier III
Power output	183 bhp at 1,760 rpm
Fuel Consumption	16.0 gal/hr
Exhaust temperature	744°F
Exhaust flow	2,066 ACFM
Stack height	40 ft
Stack diameter	5 in

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_{10} 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_2, dry basis
MW = Molecular weight, lb/lb-mol
SMV = Specific molar volume at 68°F = 385.3 dscf/lb-mol
F_d = 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 (OC 100)
2. PM_{10} emissions are based on 0.0067 lb/MMBTU (Manufacturer warranty)
3. SO_2 to SO_3 conversion in APC equipment is accounted for in the PM_{10} AP-42 emission factor
4. SOx emissions are based on 0.25 grains/100 scf (4 ppmv equivalent)

5. 30-Day Averages are based on 432 hours/month of operation, inclusive of start-up and shutdown
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 9 - Operating Scenarios

Operating Scenario	Ambient Temp °F	H_2O 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

Details 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 10 - Worst Case Operating Scenario

Parameter	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	891.7	878.7	830.7	831.9	832.1
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 (891.7 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 11 - 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_2, CO emissions to 4.0 ppmv at 15% O_2, and VOC to 2.0 ppmvd at 15% O_2. 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_2O injection into the CTGs and NH_3 injection into the SCR reactor have ceased operation

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 12 - 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_{10} (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/mmscf)	641	581	370	95	53	9	
CO (lb/mmscf)	387	352	355	299	14	14	
VOC (lb/mmscf)	14	12	6	6	6	2	
PM_{10} (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_{10} 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 480 start-ups and 480 shutdowns hours per year, with up to 2 start ups per day, with the balance of 3,040 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 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 8th minute of start-up and 25 ppmvd at 15% O_2 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 4 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 49 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. In addition to the gas turbines, the emission calculations for the emergency fire pump and cooling tower are included in Appendices D and E.

Commissioning Year Emissions
Below are 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 and the PM_{10} emissions from the 5-cell cooling tower.

Table 13-Mass Emission Rates, lb/hr (Ref: Appendix A Tables 1-6, multiplied by 5 turbines)

Equipment	Emissions, lb/hr					
5 Gas Turbines	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	41.05	40.00	11.40	2.85	30.00	30.35
Start up	52.10	93.65	14.05	2.85	30.00	N/A
Shutdown	55.00	123.65	15.00	2.85	30.00	N/A
Commissioning	365.05	363.00	14.05	2.85	30.00	N/A
Emergency Fire Pump	1.09	0.36	0.04	0.0017	0.04	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	0.444	N/A
TOTALS	**514.29**	**620.66**	**54.54**	**11.4**	**120.48**	**30.35**

Table 14-Commissioning Year Mass Emission Rates, lb/month (Ref: Appendices B, D, and E)

Equipment	Emissions, lb/month					
5 Gas Turbines	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	13,833.85	13,480.00	3,841.80	960.45	10,110.00	10,227.95
Start up	2,084.00	3,746.00	562.00	114.00	1,200.00	N/A
Shutdown	2,200.00	4,946.00	600.00	114.00	1,200.00	N/A
Commissioning	5,340.75	5,445.00	210.75	42.75	450.00	N/A
Emergency Fire Pump	18.14	1.51	0.17	0.03	0.17	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	147.98	N/A
TOTALS lb/month (30-Day Ave lb/day)	**23,476.74 (782.56)**	**27,618.51 (920.62)**	**5,214.72 (173.82)**	**1,231.23 (41.04)**	**13,108.15 (436.94)**	**10,227.95 (340.93)**

Table 15-Commissioning Year Mass Emission Rates, lb/year (Ref: Appendices C, D, and E)

Equipment	Emissions, lb/year					
5 Gas Turbines	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	119,291.30	116,240.00	33,128.40	8,282.10	87,180.00	88,197.10
Start up	25,008.00	44,952.00	6,744.00	1,368.00	14,400.00	N/A
Shutdown	26,400.00	59,352.00	7,200.00	1,368.00	14,400.00	N/A
Commissioning	47,710.70	48,642.00	1,882.70	381.90	4,020.00	N/A
Emergency Fire Pump	217.67	18.14	2.02	0.33	2.02	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	1,775.78	N/A
TOTALS	**218,627.37 109.31 tpy**	**269,204.14 134.60 tpy**	**48,957.12 24.48 tpy**	**11,400.33 5.70 tpy**	**121,777.80 60.89 tpy**	**88,197.10**

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 and the PM_{10} emissions from the 5-cell cooling tower.

Table 16-Mass Emission Rates, lb/hr (Ref: Appendix A Tables 1-6, multiplied by 5 turbines)

Equipment	Emissions, lb/hr					
5 Gas Turbines	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	41.05	40.00	11.40	2.85	30.00	30.35
Start up	52.10	93.65	14.05	2.85	30.00	N/A
Shutdown	55.00	123.65	15.00	2.85	30.00	N/A
Emergency Fire Pump	1.09	0.36	0.04	0.0017	0.04	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	0.444	N/A
TOTALS	**149.24**	**257.66**	**40.49**	**8.55**	**90.48**	**30.35**

Table 17-Non-Commissioning Year Mass Emission Rates, lb/month (Ref: Appendices B, D, and E)

Equipment	Emissions, lb/month					
5 Gas Turbines	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	14,449.60	14,080.00	4,012.80	1,003.20	10,560.00	10,683.20
Start up	2,084.00	3,746.00	562.00	114.00	1,200.00	N/A
Shutdown	2,200.00	4,946.00	600.00	114.00	1,200.00	N/A
Emergency Fire Pump	18.14	1.51	0.17	0.03	0.17	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	147.98	N/A
TOTALS lb/month (30-Day Ave lb/day)	**18,751.74 (625.06)**	**22,773.51 (759.12)**	**5,174.97 (172.50)**	**1,231.23 (41.04)**	**13,108.15 (436.94)**	**10,683.20 (356.11)**

Table 18-Non-Commissioning Year Mass Emission Rates, lb/year (Ref: Appendix C, D, and E)

Equipment	Emissions, lb/hr					
5 Gas Turbines	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	124,792.00	121,600.00	34,656.00	8,664.00	91,200.00	92,264.00
Start up	25,008.00	44,952.00	6,744.00	1,368.00	14,400.00	N/A
Shutdown	26,400.00	59,352.00	7,200.00	1,368.00	14,400.00	N/A
Emergency Fire Pump	217.67	18.14	2.02	0.33	2.02	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	1,775.78	N/A
TOTALS	**176,417.67 88.21 tpy**	**225,922.14 112.96 tpy**	**48,602.02 24.30 tpy**	**11,400.33 5.70 tpy**	**121,777.80 60.89 tpy**	**92,264.00**

30-Day Averages

The 30 Day Average emissions are calculated to determine the offset requirements. The emergency fire pump engine is exempt from offset requirements pursuant to Rule 1304(a)(4). The cooling tower is not required to obtain a written permit from the AQMD pursuant to Rule 219(d)(3)and therefore is not subject to the emission offset requirement of Regulation XIII. The 30-day average emissions are calculated in Appendix B for both a commissioning and non-commissioning year based on the worst case operating scenario, and are presented in Tables 19 below. The worst case operating scenario was defined as OC100 in Table 10 above. The values below are the cumulative 30 day averages for five gas turbines.

Table 19 - Cumulative 30-Day Averages for 5 Gas Turbines, lb/day

	30 Day Average, lb/day				
	NOx	CO	VOC	SOx	PM_{10}
Commissioning Year	781.95	920.57	173.82	41.04	432.00
Non-Commissioning Year	624.45	759.07	172.49	41.04	432.00

The 30 day average for NOx and CO are higher during a commissioning year because the SCR and CO catalyst units are usually not in full operation during the tuning and testing phase of the turbines while the units are in the commissioning period. Although VOC is usually unaffected during commissioning, it is slightly higher during the commissioning period. SOx and PM10 are not affected by commissioning because the SCR and CO catalysts do not control SOx or PM10 emissions. Therefore, the SOx and PM10 emissions remain unchanged for both commissioning and non-commissioning years.

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, 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 for WCEP 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. In addition, WCEP is proposing a new and significantly different offset strategy than was previously proposed. The new offset strategy involves the purchase and the permanent retirement of two electric utility steam boilers currently owned and operated by AESHB, in accordance with AQMD Rule 1304(a)(2). Therefore, a new public notice will be required followed by a 30-day public comment period.

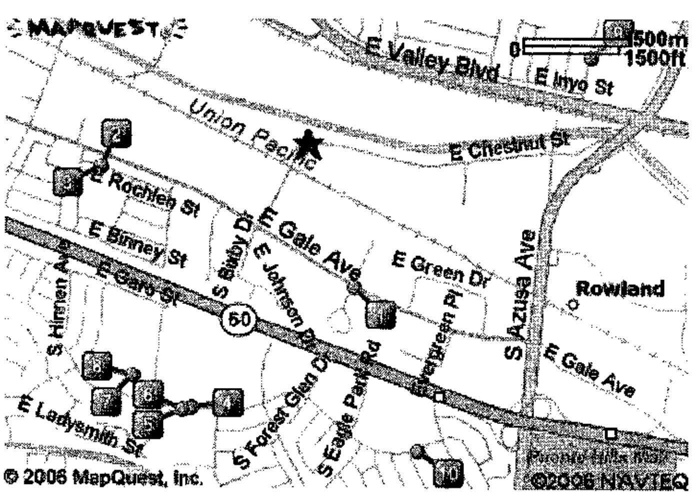
FACILITY / EQUIPMENT AND SCHOOL LOCATIONS

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)

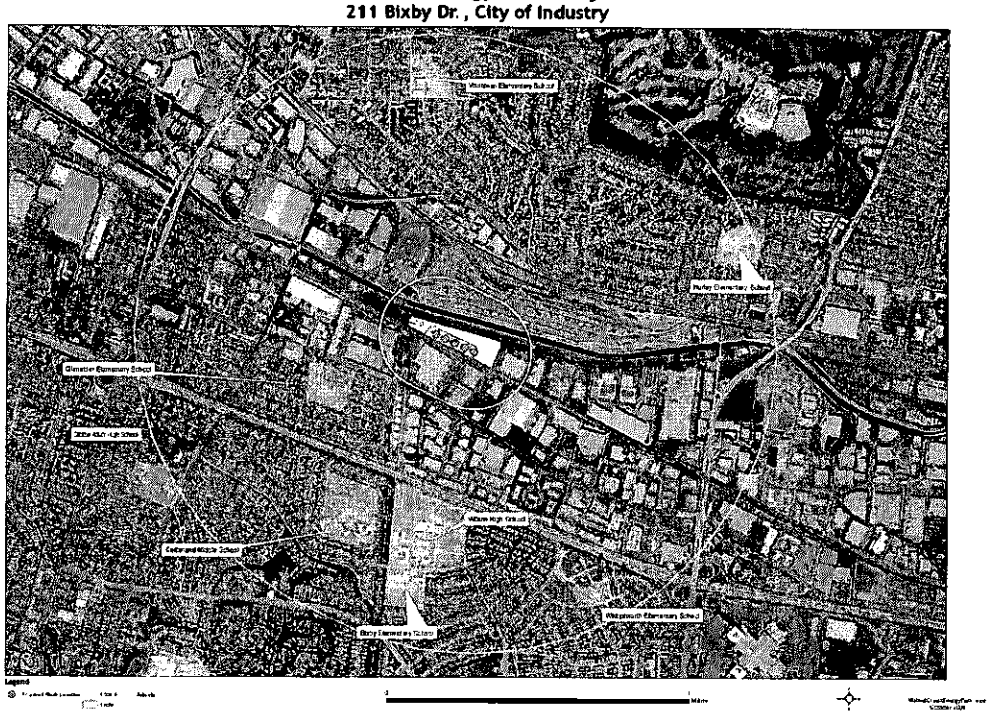
Name of School	Address	Mapquest Distance Miles (feet)	GPS Distance (feet)
1. Premier Language Center	1200 John Reed Ct, City of Industry	0.41 (2,165)	2,586
2. Glenelder Elementary School	16234 Folger St, Hacienda Heights	0.60 (3,168)	2,997
3. Hacienda La Puente Unified	16234 Folger St Hacienda Heights	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.



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



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_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the CTGs will meet the BACT limit of 4.0 ppmvd @ 15% O_2, 1-hr average, and the turbine will be conditioned as such. For SO_2, equipment which is included in SOx RECLAIM, Rule 431.1 the equipment is exempt from the SO_2 limit in Rule 407. The applicant will be required to comply with SOx RECLAIM and thus the SO_2 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_2, 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%

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

RULE 431.1-Sulfur Content of Gaseous Fuels
Although WCEP will use pipeline quality natural gas which will comply with the 16 ppmv sulfur limit, calculated as H2S, specified in this rule, they are not subject to the rule requirements since they are included in SOx RECLAIM. WCEP has provided a gas analysis which demonstrates the natural gas has a sulfur content of less than 0.25 gr/100 scf, which is equivalent to a sulfur concentration of 4 ppmv. It is also much less than the 1 gr/100 scf limit typical of pipeline quality natural gas.

RULE 474-Fuel Burning Equipment-Oxides of Nitrogen
Superseded by NOx 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_{10} mass emission limit of 11 lb/hr or a PM_{10} concentration limit of 0.01 grains/dscf. Compliance is demonstrated if either the mass emission limit or the concentration limit is met. The PM10 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. Therefore each of the following NSR rules will apply. Each piece of equipment at WCEP is evaluated for compliance with the rules in Table 20 below.

Table 20 - Applicable NSR Rules for WCEP

Applicable NSR Rules for Non-RECLAIM Pollutants (CO, VOC, SOx, PM_{10})	Applicable NSR Rules for RECLAIM Pollutants (NOx)
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 1304(a)(2)- Electrical Utility Steam Boiler Replacement	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). At the time of the initial permit evaluation for this project in 2007, BACT for simple cycle gas turbines is shown in Table 21 below:

Table 21 - BACT Requirements for Simple Cycle Gas Turbines (2007)

NOx	CO	VOC	PM_{10}/SOx	NH_3
2.5 ppmvd, at 15% O_2, 1-hour rolling average	4.0 ppmvd, at 15% O_2, 1-hour rolling average	2.0 ppmvd, at 15% O_2, 1-hour rolling average	Pipeline quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2, 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 21 were 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 22 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. Please also note that WCEP has proposed to comply with a lower CO limit of 4.0 ppmvd as indicated in the table below.

Table 22 - Proposed BACT for WCEP CTGs

NOx	CO	VOC	PM_{10}/SOx	NH_3
2.5 ppmvd, @ 15% O_2, 1-hour average	4.0 ppmvd, @ 15% O_2, 1-hour average	2.0 ppmvd, @ 15% O_2, 1-hour average	PUC quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd @ 15% O_2, 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 satisfy the current BACT requirements for NOx and will meet current BACT requirements for all remaining criteria pollutants including NH_3. 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 engine is required to employ BACT because the maximum daily emissions from this source are expected to exceed 1 lb/day. Table 23 below shows the EPA Tier 3 emission standards for an off-road compression-ignition engine rated at 183 bhp. These limits are also LAER achieved in practice and therefore required at a minimum for major sources:

Table 23 - EPA Tier 3 Certification Levels Required for Compression Ignition Engines

BHP	NMHC+NOx (gm/BHP-hr)	CO (gm/BHP-hr)	PM_{10} (gm/BHP-hr)
≥175 <300	3.0	2.6	0.15

Since WCEP is a major source, BACT requires the use of a particulate trap or compliance with the Tier 3 emission limit to control PM10 emissions. BACT for SOx emissions is the use of diesel fuel with a sulfur content of no greater than 0.0015% by weight. Table 24 shows the BACT analysis for the proposed emergency fire pump engine:

Table 24 – BACT Analysis for the Emergency Fire Pump Engine

Pollutant	EPA Tier 3 Standard	Proposed BACT	Comply (Yes/No)
NOx+NMHC	3.0 gm/BHP-hr	2.8 gm/BHP-hr	Yes
CO	2.6 gm/BHP-hr	0.90 gm/BHP-hr	Yes
PM10	0.15 gm/BHP-hr	0.10 gm/BHP-hr or particulate trap	Yes (Will meet emission limit in lieu of particulate trap)
SOx	Purchase and use of diesel fuel with a sulfur content of no greater than 0.0015% S by weight.		Yes

The emergency fire pump engine will meet the current Tier 3 emission limits as shown in Table 24 above, and will use diesel fuel with a sulfur content not to exceed 0.0015% by weight. Therefore, the emergency fire pump is expected to comply with BACT.

RULE 1303(a)-BACT – Cooling Tower

Rule 219(d)(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(d)(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.

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

In the original application, air dispersion modeling was conducted 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 submitted modeling results for both a commissioning and non-commissioning year which considered building downwash effects through the use of the EPA Building 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_2, CO, and SO_2. 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	338 $\mu g/m^3$	1 pphm	20 $\mu g/m^3$
	Annual	5.3 pphm	56 $\mu g/m^3$	0.05 pphm	1 $\mu g/m^3$
Carbon Monoxide	1-hour	20 ppm	23 $\mu g/m^3$	1 pphm	1.1 $\mu g/m^3$
	8-hour	9.0 ppm	10 $\mu g/m^3$	0.45 pphm	0.50 $\mu g/m^3$

Suspended Particulate	24-hour		50 $\mu g/m^3$		2.5 $\mu g/m^3$
Matter <10μm (PM_{10})	AGM[6]		30 $\mu g/m^3$		1 $\mu g/m^3$
Sulfate	24-hour		25 $\mu g/m^3$		1 $\mu g/m^3$

Rule 1303(b)(1) requires 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 submitted the following modeled maximum project impacts for each individual turbine at WCEP. Therefore, the numbers in Table 25 below are on a permit unit basis. Each individual turbine plus the background concentration is less than the most stringent standard.

Table 25 - 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 ($\mu g/m^3$)	Most Stringent Standard ($\mu g/m^3$)	Comply (Yes/No)
NO_2	1-hour	5.46	5.45	5.46	5.46	5.46	297	338	Yes
	Annual	0.02867	0.02867	0.02867	0.02869	0.02866	49.44	56	Yes
SO_2	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

Since PM_{10} is a non-attainment pollutant, it is required to comply with the 24-hour and annual PM_{10} significance levels in Table 26 below. This table shows the 24-hour and the annual significance levels for turbines 1 through 5.

Table 26 - Significance Modeling for WCEP for Non-Attainment Pollutants, ($\mu g/m^3$)

Equipment	24-hour PM_{10} 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). The modeling was based on a worst case scenario of all five CTGs operating 4,838 hours/year inclusive of start-ups, and also included the impacts from the uncontrolled emergency fire pump engine. 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_2, CO, PM_{10}, and SO_2. The applicant modeled the

[6] AGM is the acronym for Annual Geometric Mean

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.

WCEP proposes to increase the number of start-ups on an annual basis from the original proposal of 432 start-ups/year to 480 start-ups/year (the number of daily and monthly start-ups will not increase). In addition, WCEP proposes to increase the annual operation from 3,468 hours/year to 4,000 hours/year. The requested annual increase in start-ups from 432 to 480 is not expected to result in exceedances of the NO2 1-hour standard. Also the previous modeling was based on 4,838 hours of operation which exceeds the permitted annual operational limit of 4,000 hours. Therefore, the proposed changes are not expected to cause an increase in the hourly or annual ambient air quality standards.

The original modeling analysis performed in 2006 demonstrated compliance with the most stringent ambient NO2 air quality standards of 470 ug/m3 for one hour average and 100 ug/m3 for annual average at that time. These standards were subsequently reduced to 338 ug/m3 for one hour average and 56 ug/m3 for one hour average (state standards). As a result, WCEP recently performed another modeling analysis using AERMOD and demonstrated that the proposed project complies with the lower ambient air quality standards. This modeling analysis was reviewed and accepted by AQMD modeling staff.

RULE 1303(b)(2) and Rule 2005(b)(2)-Offsets

Walnut Creek Energy, LLC is a new facility with an emission increase. Therefore, offsets will be required for non-attainment pollutants. Offsets for CO will not be required because CO is in attainment in the South Coast Air Basin. WCEP will be included in RECLAIM program for NOx and SOx, and therefore will comply with the offset requirements by the purchase of NOx and SOx RTCs, respectively. To comply with the offset requirements for non-RECLAIM pollutants (PM10 and VOC), Edison Mission Huntington Beach, LLC (EMHB), an affiliate of WCE under common ownership of EME, will be created to purchase two electric utility steam boilers and their associated steam turbine generators (STGs) from AES Huntington Beach, LLC (AESHB) and will permanently retire these units in accordance with the requirements of AQMD Rule 1304(a)(2) to qualify for a partial offset exemption on a net megawatt to net megawatt basis. Any emissions not fully offset by the provisions of Rule 1304(a)(2) will be offset with ERCs.

Rule 1303(b)(2)

Rule 1304(a)(2) - Electric Utility Steam Boiler Replacement states that if the electric utility boilers are replaced by the combined cycle gas turbines, intercooled, or other advanced gas turbines the project will be exempt from emission offsets unless there is a basin-wide electricity generation capacity increase on a per-utility basis. If there is an increase in basin-wide capacity, only the increased capacity must be offset. The GE LMS100 gas turbine is an intercooled gas turbine and is also considered as an advanced gas turbine. Replacing the utility boiler generator with an intercooled/advanced gas turbine is allowed by Rule 1304(a)(2) and qualifies for the exemption.

The language of this exemption allows for offset and modeling exemptions on a MW to MW basis. The purpose is to facilitate the removal of older and less efficient boiler/steam turbine technology with cleaner gas turbine technology at the utilities. As previously stated the five new turbines will replace the existing boiler generators no. 3 and no. 4. The combined power generating capacity of the five new turbine generators is 500.5 MW while the combined power generating capacity of the existing two boiler generators is 450 MW. Thus there is a total increase of 50.5 MW. According to the provisions of this rule, WCE must provide offset for the emissions increases related to the 50.5 MW capacity increase.

Walnut Creek Energy, LLC Net Electrical Output = 500.5 MW
AES Huntington Gross Electrical Output = 450 MW
% Capacity Increase = [(500.5-450)/500.5] = 0.1009 = 10.09%

Table 27 – Required Offsets

	VOC	PM10
30-Day Average (lb/day)	173.82	432.00
Mulitplier (0.1009)	17.54	43.59
Offset Factor (1.2)	21.05	52.31
Offsets Required (lb/day)	21	52
Offsets Required per turbine(lb/day)	4,4,4,4,5	10,10,10,11,11

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

Fuel Use Calculation

The facility's maximum monthly and annual fuel usage (caps) for the simultaneous operation of the 5 CTGs will be 1,834 mmscf and 16,985 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 432 hours/month and 4,000 hours/year of operation. These values were selected by WCEP.

The monthly and annual fuel caps for the emergency fire pump are 64 gallons and 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:
Five CTGs = (891.7 MMBTU/hr)(1 scf/1,050 BTU)(432 hr/month)(5 CTGs) = **1,834 MMscf/month**
Single CTG = (891.7 MMBTU/hr)(1 scf/1,050 BTU)(432 hr/month) = **367 MMscf/month**
ICE = (16.0 gal/hr)*4.0 hr/month = **64 gal/month**

Annually:
Five CTGs = (891.7 MMBTU/hr)(1 scf/1,050 BTU)(4,000 hr/month)(5 CTGs) = **16,985 MMscf/year**
Single CTG = (891.7 MMBTU/hr)(1 scf/1,050 BTU)(4,000 hr/year) = **3,397 MMscf/year**
ICEFuel= (16.0 gal/hr)*200 hr/year = **3,200 gal/year**

Rule 2005(b)(2)

WCEP is required to demonstrate that it holds sufficient NOx and SOx RTCs to offset the annual emission increase for the first year of operation using a 1-to-1 offset ratio prior to start the of operation. Furthermore, Rule 2005(b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). Since this facility is located in Zone 2a, RTCs may only be obtained from either Zone 1 or Zone 2a.

As calculated in Appendix F, the total NOx RTC required for the 1st year of operation, which includes the commissioning period, is 218,628 pounds. After the 1st year, the project will require 176,418 pounds of NOx RTC per year. It is lower than the 1st year requirement since the emissions from the commissioning are not included. The total SOx RTC required for this project is 11,400 pounds for each year of the operation.

WCEP will supply the required NOx and SOx RTCs from the open market or through transfer of credits from other RECLAIM facilities prior to the start of operation. Compliance with the offset requirement of Rule 2005(b)(2) for RECLAIM pollutants 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), facilities which provide ERCs to offset their emission increases and are 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.

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. WCE 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, the parent company of WCE, 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 dated March 10, 2011 to the AQMD 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 will be addressed. Compliance is expected.

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 in Table 28 as follows:

Table 28 – 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	≤ 1.0
Chronic Hazard Index	≤ 1.0
Cancer Burden	≤ 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 29 below is a summary of the modeled health risk assessment results. The cancer burden is not calculated because the MICR is less than 1×10^{-6} for both residential and commercial receptors.

Table 29 – Rule 1401 Modeled Results

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

Table 29 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 1×10^{-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_{10} emissions up to 0.15 gm/bhp-hr, and a maximum of 100 hours per year for PM_{10} 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 Rule1470 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.

Rule 2005(g)(1) – Statewide Compliance
EME, the parent company of WCE, 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 March 10, 2011 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. WCE 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 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
AQMD will issue a new public notice for the WCEP, and therefore this project 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.

REGULATION XVII – Prevention of Significant Deterioration
The AQMD and the EPA have entered into an agreement on July 25, 2007 the AQMD is re-delegated a partial PSD authority. AQMD is authorized to issue new and modified PSD permits in accordance with AQMD's Regulation XVII.

The SCAB is in attainment for NO_2, SO_2, and CO emissions. Therefore this regulation applies to NO_2, SO_2, and CO emissions. BACT applies to all projects that have emission increases. BACT requirements for NO_2, CO, and SO_2 are evaluated in this section.

- NO_2 – The requirement is NOx emissions of 2.5 ppmv or less measured at 15% O_2, 1-hour average, dry basis. Use of the SCR for control of NOx emissions will achieve this limit and is considered BACT for simple cycle gas turbines.
- SO_2 – The requirement is to use pipeline quality natural gas. WCEP will use pipeline quality natural gas as fuel for the gas turbines. The requirement is satisfied.
- CO – The most stringent emission limit found on simple cycle gas turbines is 4.0 ppmv based on a 1-hour average, at 15% O_2, dry basis. The same limit is found on the simple cycle gas turbines permitted at the City of Riverside and the City of Anaheim. Therefore, BACT for simple cycle gas turbines is set at 4 ppmv for this project. The gas turbines will comply with this limit.

As indicated earlier, AQMD and EPA signed a new Partial PSD Delegation Agreement on July 25, 2007 which provides the authority to issue PSD permits to new sources, in particular, to AQMD. Based on the evaluation of the maximum potential to emit emissions from this project shown in Table 30 below, AQMD has determined that the project is not subject to PSD. In addition, in May 2010 EPA approved a final PSD and Title V GHG Tailoring Rule, which requires PSD analysis for GHG emissions. However, this rule only applies to new sources constructed on or after July 2011. Therefore, it does not apply to WCEP at this time.

Table 30 – WCEP Potential to Emit

	NOx	CO	SO2
Facility PTE (TPY)	109.31	134.60	5.70
Threshold (TPY)	250	250	250

NOx PTE = (218,627.37 lb/yr) (1 ton/2,000 lb) = 109.31 TPY
CO PTE = (269,204.14 lb/yr)(1 ton/2,000 lb) = 134.60 TPY
SO2 PTE = (11,400 lb/yr)(1 ton/2,000 lb) = 5.70 TPY

INTERIM PERIOD EMISSION FACTORS

RECLAIM requires a NOx and SOx 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 emission rate is assumed, and the remaining period at which controlled rates at BACT are assumed. Since WCEP will be included in NOx and SOx 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 Tables 31 and 32 below.

Table 31 - Emission Factor (Commissioning)

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

Table 32 - Emission Factor (Non-Commissioning)

Pollutants	NOx	CO
Total emissions (lbs)	176,200	225,904
Total Fuel (mmscf)	16,415.8	16,415.8
Emission Factor (lb/mmscf)	10.73	13.76

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The CEC is the lead agency for this project and WCE filed an Application for Certification (05-AFC-2) for the project on December 1, 2005. WCEP will be subject to the CEC's 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 except the AQMD's PSD and Title V permits, incorporating the permit to construct. 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. AQMD is a responsible agency under CEQA and will rely on the CEC unless determined inadequate for AQMD's purposes.

40CFR Part 51 Subpart Z Appendix S – NSR for PM2.5

On May 16, 2008 the USEPA released its final NSR rule for PM2.5 and published it in the Federal Register. The effective date of the Final NSR Rule for PM2.5 is July 15, 2008. The Final Rule specifies that for areas which are non-attainment for PM2.5 NAAQS, the state and local agencies must adopt and submit non-attainment NSR rules to implement the PM2.5 requirements for EPA's approval into the State Implementation Plan no later than July 11, 2011. Since this project is located in the South Coast Air Basin that is designated as non-attainment for PM2.5 and the AQMD has not yet adopted PM2.5 NSR rules, the requirements of NSR for PM2.5 must be implemented through Appendix S. Thus, as of July 15, 2008 all AQMD permit applications for facilities with PM2.5 emissions must be evaluated for compliance with PM2.5 requirements that are included in Appendix S.

Some of the NSR provisions in Appendix S include the major source PM2.5 threshold (100 tons per year) and significant PM2.5 emissions rate (10 tons per year). The requirements of Appendix S will not apply to facilities if the facility emissions, including existing equipment and equipment currently proposed, will result in a potential to emit of less than 100 tons of PM2.5 per year. WCEP has agreed to limit the facility total PM2.5 emissions to 60.89 tons per year (see Table 18 – Non-Commissioning Year Mass Emission Rates) which is less than 100 tons per year. Therefore, the facility and the project will be exempted from the requirements of this rule.

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_X emission limit of 15 ppmv @ 15% O_2 from Table 1 of this subpart. The turbine is required to comply with BACT for NOx which is officially at 3.5 ppmv at 15% O2, dry basis for a simple cycle plant. However, GE has submitted performance warranties which indicate the CTGs will meet a NOx level of 2.5 ppmv at 15% O2 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_2/MMBtu, which is less than 0.06 lb-SO_2/MMBTU (26 ng-SO_2/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_X 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. WCEP 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 NOx 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 WCEP 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 NOx and CO emissions continuously downstream of the control equipment which will satisfy the requirements of this regulation.

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_2 emissions with SO_2 allowances that are similar in concept to RTC's. SO_2 allowances are however, not required in any year when the unit emits less than 1,000 lbs of SO_2. Facilities with insufficient allowances are required to purchase SO_2 credits on the open market. In addition, both NOx and SO_2 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.

OVERALL EVALUATION / RECOMMENDATION(S)
Based on the results of our detailed analysis and evaluation, the AQMD has determined that the proposed project complies with all applicable federal, state and local air quality rules and regulations and, therefore, AQMD intends to issue the Permits to Construct for the new equipment described above subject to EMHB and AES Huntington Beach, LLC completing the final sale of the electric utility boilers 3 and 4 from AES to EMHB prior to issuance of the Permits to Constructs and AQMD will concurrently issue new permits for electric utility boilers 3 and 4 to EMHB with the condition that both boilers 3 and 4 will be shutdown and removed from operation prior to start of operation of the WCEP project. Prior to issuance of the final Permits to Construct for WCEP, AQMD is providing an opportunity for a 30-day public comment period and an Environmental Protection Agency (EPA) review period. AQMD will consider issuance of the final Permits to Construct only after all pertinent public and EPA comments, if any, have been timely received and considered and upon WCE and EMHB complying with the requirements described below:

- In accordance with AQMD Rule 1303(b)(2) and 1304(a)(2), WCE must provide emission offsets for the emission increases associated with the increased generating capacity. WCE will provide Emission Reduction Credits (ERCs) to offset the increases in VOC and PM10 emissions, and EMHB will shutdown electric utility boilers 3 and 4 in Huntington Beach prior to start of operation of the WCEP project to offset the remaining emission increases of VOC and PM10 from the WCEP project.
- EMHB shall complete the process of change of ownership and obtain written permits from AQMD for the electric utility boiler generators Units 3 and 4 at AES Huntington Beach Generating Station prior to issuance of Permits to Construct for WCEP. In addition, EMHB shall demonstrate to the satisfaction of AQMD that EMHB holds sufficient NOx and SOx RTCs for the electric utility boiler generators Units 3 and 4 for the compliance year in which the change of ownership occurs.

FACILITY CONDITIONS

F2.1 The operator shall limit emissions from this facility as follows:

CONTAMINANT	EMISSION LIMIT
PM2.5	Less than 60.89 tons per year
CO	Less than 112.96 tons per year

The operator shall calculate the monthly emissions for PM2.5 using the equation below and the following emission factors: PM2.5: 7.04 lb/mmcf; CO 13.76 lb/mmcf

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

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

The CO emission limit of 112.96 tons per year in this condition shall only apply during non-commissioning years. The total annual CO emissions during the commissioning year shall not exceed 134.6 tons per year.

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 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 - 13.76 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 4 ppmv.

(C) After CO CEMS certification testing - 13.76 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.
[40 CFR 51 Subpart S]

F52.1 This facility is subject to the applicable requirements of the following rules or regulations(s):

In accordance with AQMD Regulations XIII, WCEP shall not start operation of any equipment until both boiler units 3 and 4 currently located at AES Huntington Beach Generating Station have been retired and permits for boiler units 3 and 4 have been surrendered.
[Rule 1303]

PERMIT CONDITIONS

(Gas Turbines) Devices D1,D7,D13,D19,D25

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

CONTAMINANT	EMISSION LIMIT PER TURBINE
PM_{10}	2,592 LBS IN ANY ONE MONTH
VOC	1,035 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: 2.73 lb/mmcf and PM10: 7.04 lb/mmcf

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

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

For the purposes of this condition, the limit(s) shall be based on the emissions from a single turbine. During commissioning, the VOC emissions shall not exceed 1,043 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]

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 480 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 4.0 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 480 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]

A99.4 The 10.37 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]

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 480 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 4.0 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]

C1.1 The operator shall limit the fuel usage to no more than 367 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.

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 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]

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 test results shall be reported with two significant digits.
[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset]

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 Cco Fd[20.9/(20.9% - %O2 d)][(Qg * HHV)/106], where

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

Cco = Average of four consecutive 15 min. ave. CO concentration, ppm

Fd = 8710 dscf/MMBTU natural gas

$\%O_2$ d = Hourly ave. % by vol. O_2 dry, corresponding to Cco

Qg = 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]

I296.1 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient NOx 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 1st compliance year hold a minimum NOx RTCs of 43,900 lbs/yr. This condition shall apply during the 1st 12 months of operation, commencing with the initial operation of the gas turbine.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the 1st compliance year, hold a minimum of 35,458 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 1st compliance year.

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

I296.3 This equipment shall not be operated unless the operator demonstrates to the Executive Officer the facility holds sufficient SOx 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 SOx RTCs of 2,280 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 1st compliance year.

This condition shall apply to each turbine individually
[Rule 2011]

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:

NH3 (ppmv) = [a-b*c/1EE+06]*1EE+06/b

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

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.
The NOx analyzer shall be installed and operated within 90 days of initial start-up.
The operator shall use the above described method or another alternative method approved by the Executive Officer.
The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.
[Rule 1303(a)(1) - BACT, 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.
The ammonia injection rate shall not exceed 190 lb/hr
[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.
The temperature range shall remain between 715 and 817 degrees F

[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.
The pressure differential across the catalyst bed shall not exceed 12 inches of water column
[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]

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 200 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]

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]

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

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 218 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 1st 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.

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.

WALNUT CREEK ENERGY PROJECT
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Appendix A - WALNUT CREEK ENERGY PROJECT
LMS100 PA Hourly Emissions - Normal Operations

Data:

Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Emission Factor (lb/MMBTU) = (ppmvd)*(MW)*(1/SMV)*(20.9/5.9)*(Fd)*(1/1E6)
where,
controlled ppmvd = controlled concentration corrected to 15% O2
MW = molecular weight (lb/lb-mol)
SMV = specific molar volume at 68 degrees Fahrenheit = 385.3 dscf/lb-mol
Fd = dry oxygen F-factor for natural gas = 8,710 dscf/MMBTU at 68 degrees Fahrenheit
Emission Rate Uncontrolled = Emission Factor Uncontrolled (lb/MMBTU) * Heat Input (MMBTU/hr)
Emission Rate Controlled = Emission Factor Controlled (lb/MMBTU) * Heat Input (MMBTU/hr)
Uncontrolled Emissions from the CTG:
NOx = 25 ppm @ 15% O2, CO = 100 ppm @ 15% O2, VOC = 4 ppm, PM10 = 0.0067 lbs/MMBTU; SOx = 0.25 grains/100 scf

Table 1 - CO Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lbs/lb-mole)	Specific Molar Volume (dscf/lb-mole)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	100	4	28	385.3	8,710	0.2242	0.0090	199.93	8.00

Table 2 - NOx Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mole)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	25	2.5	46	385.3	8,710	0.0921	0.0092	82.11	8.21

Appendix A - WALNUT CREEK ENERGY PROJECT
LMS100 PA Hourly Emissions - Normal Operations

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Table 3 - VOC Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mol)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	4	2.0	16	385.3	8,710	0.0051	0.0026	4.57	2.28

Table 4 - PM10 Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Emission Factor[1] (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	0.0067	6.00	6.00

Table 5 - SOx Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Emission Factor[2] (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	0.00064	0.571	0.571

[1] Based on a manufacturer guarantee of 6 lb/hr at 891.7 MMBTU/hr = 0.00673 lb/MMBTU

[2] Based on a maximum sulfur content of 0.25 grains/100 scf fuel:

SOx EF = (0.25 gr/100 scf)(1 scf/1050 BTU)(1 lb/7000 gr)(1E6 BTU/MMBTU)(64 lb SO2/34 lb H2S) = 0.00064 lb/MMBTU

Table 6 - NH3 Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mol)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor (lb/MMBTU)	Emission Rate (lb/hr)
100	891.7	5	17	385.3	8,710	0.0068	6.07

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Appendix A - WALNUT CREEK ENERGY PROJECT
LMS100 PA Hourly Emissions - Start-Up / Shutdown Operations

Data:
Start-up emission factors in the table below were provided in the application by GE
Assumptions
Start-up / shutdown events will not significantly afftect SOx and PM10 emissions. Emission rates are assumed to be equal to normal operations

Table 7- Start-Up Emissions

Pollutant	Start-Up Emission Factor (lb/event)[1]	Normal Operations (lb/hr)[2]	Normal Operations (lb/hr)[3]	Start-Up Emissions (lbs/hr)
CO	15.4	8.00	3.33	18.73
NOx	7.0	8.21	3.42	10.42
VOC	2.1	2.28	0.71	2.81
PM10	N/A	N/A	N/A	6.00
SOx	N/A	N/A	N/A	0.57

[1] A start-up event is defined as the first 35 minutes of start-up, per GE specs

[2] Controlled emission rates (lb/hr)

[3]The emission rates in this column are prorated for the remaining 25 minutes of start-up by multiplying by by 25/60

Table 8 - Shutdown Emissions

Pollutant	Shutdown Emission Factor (lb/event)[4]	Normal Operations (lb/hr)[5]	Normal Operations (lb/hr)[6]	Shutdown Emissions (lb/hr)
CO	18.2	8.00	6.53	24.73
NOx	4.3	8.21	6.70	11.00
VOC	1.6	2.28	1.40	3.00
PM10	N/A	6.00	N/A	6.00
SOx	N/A	0.57	N/A	0.57

[4]Emission rates in this column occur during the first 11 minutes of shutdown, per GE specs

[5]Emission rates in this column are assumed to occur for one full hour

[6]Emission rates in this column are pro-rated for the remaining 49 minutes of shutdown by multiplying by 49/60

Appendix B - WALNUT CREEK ENERGY PROJECT
Monthly Emissions - Commissioning Year

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Table 9 - Single Turbine

Operating Condition 100	Hours per Month	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/month)	NOX (lbs/month)	VOC (lbs/month)	PM10 (lbs/month)	SOx (lbs/month)
Single Turbine Start-Up	40	18.73	10.42	2.81	6.00	0.57	749.20	416.80	112.40	240.00	22.80
Single Turbine Commissioning[1]	15	72.60	71.21	2.81	6.00	0.57	1,089.00	1,068.15	42.15	90.00	8.55
Single Turbine Normal Ops	337	8.00	8.21	2.28	6.00	0.57	2,696.00	2,766.77	768.36	2,022.00	192.09
Single Turbine Shutdown	40	24.73	11.00	3.00	6.00	0.57	989.20	440.00	120.00	240.00	22.80
Totals	**432**						**5,523.40**	**4,691.72**	**1,042.91**	**2,592.00**	**246.24**

Table 10 - Five Turbines

Operating Condition 100	Hours per Month	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/month)	NOX (lbs/month)	VOC (lbs/month)	PM10 (lbs/month)	SOx (lbs/month)
5 Turbine Start-Up	40	93.65	52.10	14.05	30.00	2.85	3,746.00	2,084.00	562.00	1,200.00	114.00
5 Turbine Commissioning[1]	15	363.00	356.05	14.05	30.00	2.85	5,445.00	5,340.75	210.75	450.00	42.75
5 Turbine Normal Ops	337	40.00	41.05	11.40	30.00	2.85	13,480.00	13,833.85	3,841.80	10,110.00	960.45
5 Turbine Shutdown	40	123.65	55.00	15.00	30.00	2.85	4,946.00	2,200.00	600.00	1,200.00	114.00
Totals	**432**						**27,617.00**	**23,458.60**	**5,214.55**	**12,960.00**	**1,231.20**
						30 Day Average	**920.57**	**781.95**	**173.82**	**432.00**	**41.04**

[1]From Table 12-Proposed Commissioning Schedule in analysis; totals divided by 5 turbines and divided by 134 hours

Appendix B - WALNUT CREEK ENERGY PROJECT
Monthly Emissions - Non-Commissioning Year

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Table 11 - Single Turbine

Operating Condition 100	Hours per Month	CO (lb/hr)	NOx (lb/hr)	VOC (lb/hr)	PM10 (lb/hr)	SOx (lb/hr)	CO (lb/month)	NOX (lb/month)	VOC (lb/month)	PM10 (lb/month)	SOx (lb/month)
Single Turbine Start-Up	40	18.73	10.42	2.81	6.00	0.57	749.20	416.80	112.40	240.00	22.80
Single Turbine Normal Ops	352	8.00	8.21	2.28	6.00	0.57	2,816.00	2,889.92	802.56	2,112.00	200.64
Single Turbine Shutdown	40	24.73	11.00	3.00	6.00	0.57	989.20	440.00	120.00	240.00	22.80
Totals	**432**						**4,554.40**	**3,746.72**	**1,034.96**	**2,592.00**	**246.24**

Table 12 - Five Turbines

Operating Condition 100	Hours per Month	CO (lb/hr)	NOx (lb/hr)	VOC (lb/hr)	PM10 (lb/hr)	SOx (lb/hr)	CO (lb/month)	NOX (lb/month)	VOC (lb/month)	PM10 (lb/month)	SOx (lb/month)
5 Turbine Start-Up	40	93.65	52.10	14.05	30.00	2.85	3,746.00	2,084.00	562.00	1,200.00	114.00
5 Turbine Normal Ops	352	40.00	41.05	11.40	30.00	2.85	14,080.00	14,449.60	4,012.80	10,560.00	1,003.20
5 Turbine Shutdown	40	123.65	55.00	15.00	30.00	2.85	4,946.00	2,200.00	600.00	1,200.00	114.00
Totals	**432**						**22,772.00**	**18,733.60**	**5,174.80**	**12,960.00**	**1,231.20**
						30 Day Average	759.07	624.45	172.49	432.00	41.04

Appendix C - WALNUT CREEK ENERGY PROJECT
Annual Emissions - Commissioning Year

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Table 13 - Single Turbine

Operating Condition 100	Hours per Year	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/year)	NOX (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)
Single Turbine Start-Up	480	18.73	10.42	2.81	6.00	0.57	8,990.40	5,001.60	1,348.80	2,880.00	273.60
Single Turbine Commissioning[1]	134	72.60	71.21	2.81	6.00	0.57	9,728.40	9,542.14	376.54	804.00	76.38
Single Turbine Normal Ops	2,906	8.00	8.21	2.28	6.00	0.57	23,248.00	23,858.26	6,625.68	17,436.00	1,656.42
Single Turbine Shutdown	480	24.73	11.00	3.00	6.00	0.57	11,870.40	5,280.00	1,440.00	2,880.00	273.60
Totals	**4,000**						**53,837.20**	**43,682.00**	**9,791.02**	**24,000.00**	**2,280.00**

Table 14 - Five Turbines

Operating Condition 100	Hours per Year	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/year)	NOX (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)
5 Turbine Start-Up	480	93.65	52.10	14.05	30.00	2.85	44,952.00	25,008.00	6,744.00	14,400.00	1,368.00
5 Turbine Commissioning[1]	134	363.00	356.05	14.05	30.00	2.85	48,642.00	47,710.70	1,882.70	4,020.00	381.90
5 Turbine Normal Ops	2,906	40.00	41.05	11.40	30.00	2.85	116,240.00	119,291.30	33,128.40	87,180.00	8,282.10
5 Turbine Shutdown	480	123.65	55.00	15.00	30.00	2.85	59,352.00	26,400.00	7,200.00	14,400.00	1,368.00
Totals	**4,000**						**269,186.00**	**218,410.00**	**48,955.10**	**120,000.00**	**11,400.00**

[1]From Table 12-Proposed Commissioning Schedule in analysis; totals divided by 5 turbines

Appendix C - WALNUT CREEK ENERGY PROJECT
Annual Emissions - Non-Commissioning Year

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Table 15 - Single Turbine

Operating Condition 100	Hours per Year	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/year)	NOX (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)
Single Turbine Start-Up	480	18.73	10.42	2.81	6.00	0.57	8,990.40	5,001.60	1,348.80	2,880.00	273.60
Single Turbine Normal Ops	3040	8.00	8.21	2.28	6.00	0.57	24,320.00	24,958.40	6,931.20	18,240.00	1,732.80
Single Turbine Shutdown	480	24.73	11.00	3.00	6.00	0.57	11,870.40	5,280.00	1,440.00	2,880.00	273.60
Totals	4,000						**45,180.80**	**35,240.00**	**9,720.00**	**24,000.00**	**2,280.00**

Table 16 - Five Turbines

Operating Condition 100	Hours per Year	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/year)	NOX (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)
5 Turbine Start-Up	480	93.65	52.10	14.05	30.00	2.85	44,952.00	25,008.00	6,744.00	14,400.00	1,368.00
5 Turbine Normal Ops	3040	40.00	41.05	11.40	30.00	2.85	121,600.00	124,792.00	34,656.00	91,200.00	8,664.00
5 Turbine Shutdown	480	123.65	55.00	15.00	30.00	2.85	59,352.00	26,400.00	7,200.00	14,400.00	1,368.00
Unit 1 Totals	4,000						**225,904.00**	**176,200.00**	**48,600.00**	**120,000.00**	**11,400.00**

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Appendix D - WALNUT CREEK ENERGY PROJECT
Emergency Fire Pump Emissions

Data:
Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Manufacturer: Clarke
Model No.: JU6H-UFAD58
Type of Fuel: No. 2 Diesel w/ 15 ppm sulfur compounds by weight
Rated Power: 183 bhp at 1760 rpm
Engine Design: Lean Burn
EPA Tier III engine

Assumptions:
Steady speed, steady load operations

Table 17 - Emergency Fire Pump Emissions

Pollutant	Emission Factor[1] (gm/BHP-hr)	Maximum Rated Power (BHP)	Conversion Factor (gm/lb)	Emission Rate (lb/hr)	Annual Emission Rate[2] (lb/year)	Monthly Emission Rate[3] (lb/month)	30 Day Average[4] (lb/day)
NOx	2.70	183	454	1.09	217.67	18.14	1
CO	0.90	183	454	0.36	18.14	1.51	0
VOC	0.10	183	454	0.04	2.02	0.17	0
PM10	0.10	183	454	0.04	2.02	0.17	0
SOx	0.0041	183	454	0.0017	0.33	0.03	0

[1] Provided by the engine manufacturer (Clarke)
[2] Emission rate (lb/hr) multiplied by 200 for NOx & SOx and 50 for remaining pollutants
[3] Emission rate (lb/year) divided by 12
[4] Emission rate (lb/month) divided by 30

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Appendix E - WALNUT CREEK ENERGY PROJECT
Cooling Tower Emissions

Data:
Manufacturer: Marley
No. of cells: 5
Drift Loss: 0.0005%
Maximum TDS in Circulating Water: 5,000 mg/l
Circulating Water Rate: 35,500 gpm
Fan Exit Height : 39.09 ft AGL
Exhaust Fan Diameter: 22 ft
PM10 Emissions (lb/hr) = (Maximum TDS)*[(3.785*60)/(454*1000)]*(Circulating Water Rate)*(Drift Loss)
Water Source: Reclaimed/Recycled Water
Tower Dimensions: Deck Height: 27.09 ft AGL; Deck Length: 210.7 ft; Deck Width: 36.67 ft

Assumptions:
Cooling tower emissions based on 4,000 hr/yr operation
100% of TDS in solution is converted to PM10 at a drift loss of 0.0005%

Table 18 - Cooling Tower PM10 Emissions

Pollutant	Maximum TDS in circulating water (mg/l)	Circulating Water Rate (gpm)	Drift Loss (percent)	PM10 Emissions (lb/hr)	PM10 Emissions (lb/year)	PM10 Emissions[11] (lb/month)	30 Day Average[12] (lb/day)
PM10	5,000	35,500	0.00050	0.4439	1,775.78	147.98	5

[11] PM10 emissions (lb/year) divided by 12
[12] PM10 emissions (lb/month) divided by 30

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Appendix F - WALNUT CREEK ENERGY PROJECT
SOx RTC Calculations

Data:
Operating Schedule:
Annual Operations = 4,000 hours/year

Table 19 - SOx RTC Calculations

Operating Condition 100	Hours per Year	SOx (lb/hr)	SOx (lb/year) per device	SOx (lb/year) cumulative
CTGs				
Startup	0	0.00	0.00	0.00
Shutdown	0	0.00	0.00	0.00
Normal Operation	4,000	0.57	2,280.00	11,400.00
Commissioning	0	0.00	0.00	0.00
CTG Totals	4,000		2,280.00	11,400.00
Emergency Fire Pump	50	0.0017	0.09	0.09
Total SOx Emissions (lb/year)			2,280.09	11,400.09
Offset Ratio			1.00	1.00
SOx RTCs required (lb/year)			**2,280.09**	**11,400.09**

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Appendix F - WALNUT CREEK ENERGY PROJECT
First Year NOx RTC Calculations

Data:
Operating Schedule (1st Year):
Startups = 480 hours/year
Shutdowns = 480 hours/year
Normal Operations = 2,906 hours/year
Commissioning Period =134 hours

Table 19 - 1st Year RTC Calculations

Operating Condition 100	Hours per Year	NOx (lb/hr)	NOx (lb/year) per device	NOx (lb/year) cumulative
CTGs				
Startup	480	10.42	5,001.60	25,008.00
Shutdown	480	11.00	5,280.00	26,400.00
Normal Operation	2,906	8.21	23,858.26	119,291.30
Commissioning	134	71.21	9,542.14	47,710.70
CTG Totals	4,000		43,682.00	218,410.00
Emergency Fire Pump	200	1.09	217.60	217.60
Total 1st Year Emissions (lb/year)			43,899.60	218,627.60
Offset Ratio			1.00	1.00
1st year RTCs required (lb/year)			**43,899.60**	**218,627.60**

Appendix F - WALNUT CREEK ENERGY PROJECT
Subsequent Year NOx RTC Calculations

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Data:
Operating Schedule (1st Year):
Startups = 480 hours/year
Shutdowns = 480 hours/year
Normal Operations = 3,040 hours/year

Table 20 - Subsequent Year RTC Calculations

Operating Condition 100	Hours per Year	NOx (lb/hr)	NOx (lb/year) per device	NOx (lb/year) cumulative
CTGs				
Startup	480	10.42	5,001.60	25,008.00
Shutdown	480	11.00	5,280.00	26,400.00
Normal Operation	3,040	8.21	24,958.40	124,792.00
Commissioning	0	0.00	0.00	0.00
CTG Totals	4,000		35,240.00	176,200.00
Emergency Fire Pump	200	1.09	217.60	217.60
Subsequent Year Emissions (lb/year)			35,457.60	176,417.60
Offset Ratio			1.00	1.00
Subsequent year RTCs required (lb/year)			**35,457.60**	**176,417.60**

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Appendix G - WALNUT CREEK ENERGY PROJECT
Emission Factors[1]

Total Annual Hours of Operation = 4,000 hours
Total Hours of Commissioning = 134 hours
Total Hours During Non-Commissioning = 3,866 hours

Table 21 - Fuel Consumption During the Commissioning Period

Commissioning Schedule	Hours per Phase	Heat Input (MMBTU/hr)	Fuel Heating Value (BTU/scf)	Fuel Consumption (MMscf/hr)	Fuel Consumption per Phase (MMscf)	Cumulative Fuel Cons. during Comm. (MMscf)
Phase 1	20	750	1,050	0.7143	14.2857	14.2857
Phase 2	14	900	1,050	0.8571	12.0000	26.2857
Phase 3	24	2500	1,050	2.3810	57.1429	83.4286
Phase 4	12	4,503	1,050	4.2886	51.4629	134.8914
Phase 5	24	3,500	1,050	3.3333	80.0000	214.8914
Phase 6	40	4,503	1,050	4.2886	171.5429	386.4343

Table 22 - Commissioning Period Emission Factor

Commissioning Schedule	Fuel Consumption per Phase (MMscf)	NOx Emissions per Phase (lb)	CO Emissions per Phase (lb)	NOx EF lb/mmscf	CO EF lb/mmscf
Phase 1	14.2857	9,100	5,500		
Phase 2	12.0000	6,930	4,200		
Phase 3	57.1429	21,000	20,160		
Phase 4	51.4629	4,860	15,300		
Phase 5	80.0000	4,200	1,080		
Phase 6	171.5429	1,620	2,400		
TOTALS	386.4343	47,710	48,640	**123.46**	**125.87**

[1] The heat input values, fuel consumptions, and emissions during each phase of commissioning are for all five CTGs

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Appendix G - WALNUT CREEK ENERGY PROJECT
Emission Factors[2]

Annual fuel consumption (AFC) during non-commissioning is calculated as follows:
AFC = (5 CTGs)(891.7 MMBTU/hr)(1 scf/1,050 BTU)(4,000 hr/yr) = 16,985 MMscf/yr

Table 23 - Emissions During the Non-Commissioning Period

Total NOx Emissions (lb/yr)	Total CO Emissions (lb/yr)	Total SOx Emissions (lb/yr)	AFC (MMscf/yr)	NOx EF lb/mmscf	CO EF lb/mmscf
176,200	225,904	11,400	16,415.8	10.7336	13.7614

[2] The total NOx, CO and SOx emissions as well as the AFC are for all 5 CTGs

Table 24 - Emission Factor Determination for Condition A63.1

PM10 EF lb/MMBTU	SOx EF gr/100 scf	VOC EF lb/MMBTU	Grains/lb	Heat Content BTU/scf	PM10 lb/mmscf	SOx lb/mmscf	VOC lb/mmscf
0.0067	0.250	0.0026	7,000	1,050	7.04	0.67	2.73

APPENDIX H

COMMENTS AND RESPONSES FOR THE PUBLIC NOTICE PUBLISHED IN NOVEMBER 2006

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.

COMMENT	AQMD RESPONSE
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 intial 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.	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 itnitial turbine start-up is not necessary. After in-house discussions, EME elected to withdraw this comment.

COMMENT	AQMD RESPONSE
The 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: PM10 = 2,776 lb/month; CO = 6,484 lb/month; VOC = 1,168 lb/month; SOx = 287 lb/month. 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.	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: PM10 = 2,778 lb/month CO = 6,532 lb/month VOC = 1,106 lb/month SOx = 281 lb/month 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.
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	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.
CO CEMS data should be used prior to CEMS certification test rather than relying on emission factors and fuel use.	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.

COMMENT	AQMD RESPONSE
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.	Condition A63.2 has been removed from the facility permit. However, if the modeling had been based on annual emissions < 12 times the max monthly limits, then condition A63.2 would have remained in the permit.
WCEP proposes to remove the 1-hour start-up time limit, because the intial 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 continuosly monitored by the NOx CEMS.	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
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 condtion A99.3	Emissions are required to be monitored and reported during all phases of operation, including start-up, shut down, commissioning (1st 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.

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.

COMMENT	AQMD RESPONSE
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.	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.
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.	It appears that the efficiencies sited 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 & CO emissions are determined by the reduction efficiency of the SCR system.
Were the potential air quality benefits of the LMS100 STIG configuration factored into AQMD's evaluation of the WCEP permit?	The WCEP CTGs are equipped with water injection and configured to include an SCR/CO catalyst to further reduce the NOx & 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.

COMMENT	AQMD RESPONSE
Rule 1303(b)(2) seems to require offsets for the ammonia emissions even though BACT is met. Please comment.	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) an 1303(b)(2) imply that NH3 is not a non-attainment pollutant and as such offsets for NH3 are not required.
Hydrogen Ventures, Inc, requests AQMD to comment on why NH3 emissions are not factored into determination of PM2.5 emissions from the proposed project	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.
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.	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.

APPENDIX I

COMMENTS AND RESPONSES FOR THE PUBLIC NOTICE PUBLISHED IN JANUARY 2008

Comment No. 1 from EPA
EPA notes that throughout the proposed permit "Rule 1703" is listed as the basis for numerous permit conditions. However, as stated on page 15 of the engineering analysis, total facility emissions of attainment pollutants are less than 250 tpy, therefore the provisions of PSD, as specified in Rule 1703 are not applicable. Accordingly, please remove all references to Rule 1703 as the basis for any condition in the permit.

AQMD Response
AQMD agrees with EPA in that the applicable major stationary source PSD thresholds for simple cycle power plants is 250 tons per year (tpy) for any attainment pollutant regulated by the federal Clean Air Act. However, Rule 1703(a)(2) requires that each permit unit be constructed using Best Available Control Technology (BACT) for each attainment air contaminant where there is a net emission increase. Since carbon monoxide (CO), nitrogen dioxide (NO_2), and sulfur dioxide (SO_2) are attainment air contaminants with increased emissions, Rule 1703(a)(2) applies to this facility. Therefore, the appropriate permit conditions will be revised from the previously tagged "Rule 1703" to state "Rule 1703(a)(2) PSD-BACT".

Comment No. 2 from EPA
Conditions D12.3 and D12.4 establish temperature and differential pressure ranges for the catalyst. EPA notes that no provisions are made to account for operation during the startup period, during which the catalyst may not be able to comply with the required ranges. If the emission units can not comply during the startup period, the permit should be revised to specify what the temperature and pressure requirements are during the start up period.

AQMD Response:
AQMD agrees with EPA regarding the need for maximum temperature and pressure limits and will revise conditions D12.3 and D12.4 to include a maximum temperature and pressure limit which cannot be exceeded during the start-up period.

Comment No. 3 from EPA
Condition C1.4 states that "the operator shall limit the *operating time* to no more than 4,000 hours in any one year. For the purpose of this condition, *operating time* shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new twelve month period beginning on the first day of each calendar month." (Emphasize added) Please revise the second sentence to read that "one year" rather than "operating time" shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new twelve month period beginning on the first day of each calendar month.

AQMD Response:
AQMD agrees with EPA and will revise the second sentence to read "one year".

Comment No. 4 from EPA
While Condition C1.4 limits the annual hours of operation for the turbines, and Condition D12.7 requires the installation of a non-resettable elapsed time meter, EPA could not locate any requirement to monitor and record the hours of operation in Section K of the permit. Please add a condition requiring at least monthly monitoring and recordkeeping of the elapsed time meter readings.

AQMD Response:
AQMD agrees with EPA and will revise condition D12.7 to require at least monthly monitoring and recordkeeping of the elapsed time meter readings.

Comment No. 5 from EPA
EPA notes that for several of the conditions related to source testing, found in Subsection D of Section H of the permit (e.g. see Condition D29.3), the required test method is listed as "Approved District Method." Since specific SIP approved test methods are available for each of these tests, the Title V permit must list the specific test methods required to be used. The District may add a condition stating that an alternative test method may be allowed, but only upon both District and EPA concurrence. In a similar manner, many of these same conditions specify that the required Averaging Time is "District-approved averaging time." Again each specific test method has a corresponding required averaging time. Please revise all Conditions in Subsection D to provide specific test method and averaging time requirements.

AQMD Response:
AQMD concurs with EPA and will make the following revisions to the appropriate source testing conditions: The required averaging time for PM will be revised from "District approved averaging time" to read "4 hours". The required test method for PM will be revised from "Approved District Method" to read "Method 5". The required test method for SOx will be revised from "Approved District Method" to read AQMD Method 307-91." The required test method for VOC will be revised from "Approved District Method" to read "AQMD Method 25.3".

Comment No. 6 from EME
EME has indicated to AQMD that their interpretation of the language in Rule 1309.1 is that an in-District electrical generating facility located in Zone 2 shall demonstrate compliance with each of the subsections in subparagraph (iii) of the rule with no references to a limitation on total megawatts (MW) of electricity generated. Thus EME does not need proposed condition E193.4 which limits the total electrical generating capacity to 500 MW or less

AQMD Response:
Upon review of the rule language in Rule 1309.1, the AQMD concurs with this interpretation. Therefore, condition E193.4, will be removed from the amended Determination of Compliance issued on January 11, 2008. Please note that condition E193.4 corresponds to AQ -19 in the CEC AFC document and should be removed accordingly.