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Preliminary
Determination of Compliance

(Preliminary New Source Review Document)

Sonoran Energy Project
Blythe, California

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Executive Director

Mojave Desert Air Quality Management District

December 18, 2015

List of Abbreviations

ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
BEP	Blythe Energy Project
CARB	California Air Resources Board
CEC	California Energy Commission
CO	Carbon Monoxide
CTG	Combustion Turbine Generator
EGU	Electric utility steam Generating Unit
HDPP	High Desert Power Project
HRA	Health Risk Assessment
HRSG	Heat Recovery Steam Generator
LAER	Lowest Achievable Emission Rate
MDAQMD	Mojave Desert Air Quality Management District
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
O_2	Molecular Oxygen
$PM_{2.5}$	Fine Particulate, Respirable Fraction ≤ 2.5 microns in diameter
PM_{10}	Fine Particulate, Respirable Fraction ≤ 10 microns in diameter
PSD	Prevention of Significant Deterioration
SCIA	Southern California International Airport
SCR	Selective Catalytic Reduction
SEP	Sonoran Energy Project
SO_2	Sulfur Dioxide
SO_x	Oxides of Sulfur
STG	Steam Turbine Generator
TOG	Total Organic Gases
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

Introduction & History

The Mojave Desert Air Quality Management District (MDAQMD) received an Application for New Source Review for the Sonoran Energy Project (SEP) on August 10, 2015. The MDAQMD notified the applicant that this application was complete with a letter dated September 18, 2015. This document is the Preliminary Determination of Compliance (PDOC), for the proposed project as required by Rule 1306.

Pursuant to MDAQMD Rule 1306(E)(1)(a), this document will review the proposed project, evaluating worst-case or maximum air quality impacts, and establish control technology requirements and related air quality permit conditions. This document represents the preliminary pre-construction compliance review of the proposed project, to determine whether construction and operation of the proposed project will comply with all applicable MDAQMD rules and regulations.

The SEP is owned by Altagas Sonoran Energy, Inc. and the Blythe Energy Project (BEP) is owned by Blythe Energy, Inc. which are subsidiaries of the same parent company, Altagas Power Holdings (U.S.) Inc. (APHUS). BEP and SEP are under common control and located on contiguous property and therefore are considered one stationary source as defined in Rule 1301(Y). Permits for BEP were issued by the District in 2000 and offsets as required by Rule 1303(B) were surrendered when the facility was constructed. In 2004 the District received an application for the Blythe Energy Project Phase II (BEPII). The District conducted a New Source Review analysis for BEPII as required by Rule 1306 and issued ATCs for BEPII. At the time that the original permits were issued, BEP and BEPII were under common control and were considered one stationary source and the addition of the new emission units associated with BEPII was considered a modification of an existing stationary source (BEP). In 2009, BEPII was modified and had been acquired by Caithness Blythe II, LLC and was no longer under common control with BEP. In the 2009 modification, BEP and BEPII were no longer classified as a single stationary source and the offset burden was re-evaluated independent from BEP. In May 2014 BEP and BEPII were both acquired by APHUS. APHUS requested that the District change the ATCs for BEPII to reflect a new facility name, SEP. To date SEP as permitted has not been built, nor have emission reduction credits been surrendered to satisfy the offset burden associated with SEP. Although a single stationary source BEP and SEP are owned by different subsidiaries and therefore maintain separate District permits. BEP operates under federal operating permit 130202262. SEP has applied for a federal operating permit which will be processed separately from the current NSR permitting action for the revised SEP.

Proposal

SEP is requesting approval from the District to construct and operate an electrical generating facility with a nominal net rating of 553 MW. The project will be a combined cycle power generation facility.

The SEP is subject to approval by the California Energy Commission (CEC). The CEC is the lead agency for the proposed project for the requirements of the California Environmental

Quality Act (CEQA). Because SEP emits attainment air pollutants, PSD may be applicable. MDAQMD has not been delegated authority to implement PSD by the USEPA. USEPA Region IX holds the sole authority to determine PSD applicability for the SEP. SEP also emits air pollutants in an area designated non-attainment for those pollutants therefore the facility is subject to MDAQMD Regulation XIII – New Source Review. BEP and SEP are under common control and located on contiguous property they are considered one stationary source under Regulation XIII. The combined emissions of BEP and SEP are in excess of the thresholds specified in Rule 1303(B) and classify the facility as a Major Source. The combined emissions for BEP and SEP are in excess of the thresholds specified in Rule 1201(S) therefore the facility is also subject to Title V.

Project Location

The project is located within the City of Blythe, approximately 5 miles west of the center of the city. SEP will be located on a 76-acre site immediately adjacent to the existing, operational BEP. The SEP and BEP facilities are bounded on the south by Hobsonway and on the east by Buck Boulevard.

The proposed project site is located 25,112 feet from the closest K-12 school.

Process Description

<u>Combined-Cycle Combustion Turbine Generator</u>

The natural gas fired General Electric 7HA.02 combined cycle combustion turbine will be equipped with a Dry Low NOx combustor, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner and a heat recovery steam generator (HRSG). The CTG will have a nominal rating of 3320 MMBtu/hr on a higher heating value basis and will drive an electrical generator nominally rated at 553 MW.

The plant is combined-cycle because the waste heat in the gas turbine exhaust is recovered and used to drive a steam turbine. The single shaft combined cycle system consists of one gas turbine (CTG), one steam turbine, one generator and one HRSG with the gas turbine and steam turbine coupled to a single generator in a tandem arrangement.

A Continuous Emissions Monitoring System (CEMS) will sample, analyze and record NOx and CO concentrations in the exhaust gas from the CTG.

<u>Heat Recovery Steam Generator with Supplementary Duct Burner</u>

The HRSG is a multi-pressure, natural circulation boiler which provides for the transfer of heat from the CTG exhaust gases to condensed feedwater to produce steam. Steam will be produced in the HRSG and will flow to the Steam Turbine Generator (STG). The STG will drive an electrical generator and produce power. The HRSG has a natural gas-fired duct burner for supplemental firing in the HRSG inlet ductwork and an emission reduction system consisting of a SCR unit to control NOx stack emissions from the CTG and HRSG duct burner and an oxidation catalyst to control carbon monoxide (CO) emissions from the CTG and HRSG duct burner. The duct burner will have a maximum rating of 221.6 MMBtu/hr on a higher heating value basis.

STG exhaust steam will be condensed in a surface condenser with water from a mechanical draft wet cooling tower. The CTG and HRSG duct burner will be exclusively fueled by pipeline-quality natural gas, without back-up liquid fuel firing capability.

Steam Turbine Generator

The General Electric D652 steam turbine is nominally rated at 210 MW. Steam from the HRSG enters the STG and expands as it travels through the turbine blades turning them which drives the electrical generator producing power.

Auxiliary Boiler

One 66.3 MMBtu/hr Babcock & Wilcox FM 9-52 (or equivalent) natural gas fired steam boiler will provide steam during gas turbine start-up to allow startups to be accomplished more quickly. The boiler will be equipped with an Ultra-Low NOx burner and will have the capacity to produce 30,000 lb/hr of steam.

Emergency Internal Combustion Engine Powering Fire Pump

One Tier III diesel fired internal combustion engine will fuel a fire pump. In the event that electrical pump motors cannot maintain proper pressure in the piping network the proposed diesel fired engine will power the fire pump. The proposed engine is rated at 238 hp.

10 Cell Wet Cooling Tower

One induced-draft, 10-cell cooling tower with a circulation rate of 129,480 gallons/minute to provide cooling to the surface steam condenser and closed cooling water heat exchanger which cool reject steam from the STG which is utilized as feed water to the HRSG. The cooling tower will be equipped with high efficiency drift eliminators.

Project Emissions

The SEP will produce exhaust emissions during three basic performance modes: startup; operations mode; and shutdown. In addition to combustion related emissions, the project will have evaporative and entrained particulate emissions due to the operation of evaporative cooling towers. Turbine emissions estimates for NOx, VOC, CO and PM10 are based on manufacturer data. Emissions estimates for SOx are based on sulfur content in the fuels used. The following assumptions were used in the emissions calculations:

Maximum Annual Emissions

Table one presents maximum annual facility operational emissions. Maximum annual emissions are calculated based on the following assumptions:

CTG

- HHV = 1036 Btu/scf
- Maximum annual emissions estimated using:
    - 5500 hours of operation at full load without duct firing
    - 1500 hours of operation at full load with duct firing

- o 50 cold start events each lasting up to 45 minutes with the balance of the hour normal operation at 39° F at 100 percent hourly rate with duct firing
- o 150 warm start events each lasting up to 40 minutes with the balance of the hour normal operation at 39° F at 100 percent hourly rate with duct firing
- o 200 shut down events each lasting up to 14 minutes with the balance of the hour normal operation at 39° F at 100 percent hourly rate with duct firing

- Maximum annual SO_x emissions are calculated based on the hours specified above with a fuel sulfur content of 0.25 grains/100 scf and complete conversion of fuel sulfur to exhaust SO_x.
- Annual NH3 emissions are based on 5 ppmvd slip

Auxiliary Boiler
- 6600 hours of operation at 100% load
- 400 hours per year startup/shutdown events

Emergency Internal Combustion Engine, Fire Pump
- Potential to Emit based on 50 hours per year normal maintenance and testing hours
- Impact modeling based on 200 hours/year operation

Cooling Tower
- 8760 hours of operation

Maximum Facility Emissions					
All emissions in tons per year					
	NO_x	**VOC**	**CO**	**SO_x**	**PM_{10}**
Existing BEP	97.0	24.0	97.0	24.0	97.0
BEP Proposed Reduced Emission Limits (a)	97.0	24.0	97.0	12.0	56.0
New Emissions SEP	85.6	24.3	78.0	8.8	40.1
Maximum Facility Emissions (BEP + SEP)	182.6	48.3	175.0	20.8	97.0

(a) PDOC issued 12/18/15

Maximum Daily Emissions

CTG

- 20 hours of operation at 100% load with duct firing
- 1 cold start
- 1 hot start
- 2 shut down events
- Maximum daily SO_x emissions are calculated by assuming 24 hours of operation at the maximum fuel use rate (with duct burners) with a fuel sulfur content of 0.5 grains/100 scf and complete conversion of fuel sulfur to exhaust SO_x
- Maximum daily PM_{10} emissions are calculated by assuming 24 hours of operation at 100 percent load with duct burner hourly rate
  - Maximum daily emissions estimated using:
    - 20 hours of normal operation at full load with duct firing
    - 1 cold start up event lasting up to 45 minutes with the balance of the hour normal operation at 39° F at 100 percent hourly rate with duct firing
    - 1 hot start up event lasting up to 21 minutes with the balance of the hour normal operation at 39° F at 100 percent hourly rate with duct firing
    - 2 shut down events lasting up to 14 minutes with the balance of the hour normal operation at 39° F at 100 percent hourly rate with duct firing

Auxiliary Boiler

- 20 hours of operation at 100% load
- 2 startup events
- 2 shut down events

Emergency Internal Combustion Engine, Fire Pump

- Potential to Emit based on 50 hours per year normal maintenance and testing hours
- Impact modeling based on 24 hours/day operation

Cooling Tower

- 24 hours of operation

The following tables summarize the expected emissions from the proposed equipment:

PTE CTG & DB								
	MMBtu	MMcf						
	71158	68.6853282		NOx	CO	VOC	SOX	PM10
	14231.6	13.7370656	LB/DAY	879.95	887.42	281.10	117.63	238.23
	19568450	18888.4653	TON/YEAR	84.8	68.5	26.7	8.65	31.40
	5002950	4829.10232						
	1423160	1373.70656						
			PTE					
			hours/day normal	20				
			hours/day su/sd	4				
			hours/year normal no df	5500				
			hours/year normal with df	1500				
			hours/year su/sd	400				
			worst case day su/sd - one cold one hot start					
			worst case annual su/sd - 50 cold starts, 150 warm starts					
			worst case annual su/sd - 50 cold starts, 150 warm starts					

Table 3.1B-3
Sonoran Energy Project
Emissions and Operating Parameters for Auxiliary Boiler

	Babcock & Wilcox FM 10-66 Package Boiler or equivalent		
Mfr/Model			
Fuel	Natural Gas		
Load	100%	50%	25%
Steam Production, lb/hr	50,000	25,000	12,500
Steam Pressure, psi	300.00	300.00	300.00
Maximum Heat Input (MMBtu/hr)	66.3	32.3	16.2
F-factor (dscf/MMBtu)	8,710		
Reference O2	3.00%		
Actual O2	3.00%		
Exhaust Temperature (F)	600	480	441
Exhaust Rate (dscfm @ 3% O2)	10,958	5,335	2,683
Exhaust Rate (wacfm @ actual O2)	28,481	12,297	5,927

Pollutant	Emission Rate, ppmvd @ 3% O2	Emission Factors (lb/MMBtu)	Maximum Emissions (lb/hr)	MDAQMD verification					
				lb/hr	lb/day	lb/year	tpy	PTE	
NOx (normal operation)	7	0.01	0.56	0.56	11.15	3680.57	1.84	hours/day normal	20
NOx (startup/shutdown)	25	0.03	1.99	1.99	7.97	796.66	0.40	hours/day su/sd	4
NOx (boiler tuning)	100	0.12	7.97	7.97	191.20	1593.32	0.80	hours/year normal	6600
SOx		0.00	0.09	0.09	2.19	319.46	0.16	hours/year su/sd	400
CO (normal operation)	50	0.04	2.43	2.43	48.50	16006.55	8.00	hrs tuning	200
CO (startup/shutdown)	250	0.18	12.13	12.13	48.50	4850.47	2.43		
VOC (normal operation)	10	0.00	0.28	0.28	5.56	1833.59	0.92		
VOC (startup/shutdown)	25	0.01	0.69	0.69	2.78	277.82	0.14		
PM10	0.005	0.01	0.46	0.46	11.13	3246.72	1.62		
	gr/dscf						0		

Stack Diameter	35	inches	0.89	meters
Stack Height	50	feet		

emission factors for Nox, CO, VOC, PM10 provided by applicant/manufacturer
emission factor for Sox based on sulfur content of fuel
spreadsheet provided by applicant, reviewed,verified and approved by MDAQMD

START UP & SHUT DOWN & COMMISSIONING

Startup and shutdown periods are a normal part of the operation of natural gas-fired power plants. They involve emission rates that are greater than emissions during steady-state operation and that are highly variable. Emissions are greater during startup and shutdown for several reasons. One reason is that during startup and shutdown, the turbines are not operating at full load where they are most efficient. Another reason is that the exhaust temperatures are lower than during steady-state operations. Post-combustion emissions control systems such as the SCR catalyst and oxidation catalyst do not function optimally at lower temperatures, and so there may be partial or no abatement for NOx, carbon monoxide and precursor organic compounds for a portion of the startup period. Thus, emissions can be minimized by reducing the duration of the startup sequence and by reducing emissions during the startup. Although the number of startup and shutdown events are not specifically limited the turbine has fuel throughput and emissions limits based on a worst case operating scenario which included one cold startup, one hot startup and two shut down events per day. Emissions from startup and shutdown events are limited by permit condition on a lb per event basis. The GE turbine has been designed with two types of starts, Rapid Response which brings the turbine to full load as quickly as possible and Rapid Response Lite which brings the turbine to an emissions (BACT) compliant load as quickly as possible. The lb per event limits specified in the turbine permit conditions are those for Rapid Response.

Event	Duration, minutes	Emissions, lb/hr			
		NOx	**CO**	**VOC**	**PM10/PM2.5**
Cold Start	45	188	132	10	6.6
Warm Start	40	155	130	10	5.9
Hot Start	21	114	123	9	3.1
Shutdown	14	25	136	28	2.1

The commissioning period which includes initial startup, tuning and adjustment of the CTG and associated equipment has been limited by permit condition to 1,250 hours and a maximum of 180 days, commencing with the first firing of fuel in this equipment during which time the NOx, CO, VOC and NH3 concentration limits do not apply.

Table 3.1B-4
Sonoran Energy Project
Emissions and Operating Parameters for Emergency Fire Pump Engine

Make/Model	Clarke JU6H-UFADR0 or equivalent	
EPA Emissions Certification	Tier 3	
Rating	238	bhp
Fuel	Diesel	
Fuel Consumption	11.7	gal/hr
	1.61	MMBtu/hr(1)
Exhaust Temperature	848	deg F
Exhaust Diameter	6.065	inches
Exhaust Flow Rate	1513	acfm
Exhaust Velocity	125.7	ft/sec

	NOx	CO	VOC	SOx	PM10
Tier III Standard g/bhp-hr	2.84	2.61	0.15		0.15
Emission Factor (g/bhp-hr)	2.56	0.60	0.07	0.00	0.08
Hourly Emissions (lb/hr)	1.34	0.31	0.04	0.00	0.04
Daily Emissions (lb/dy)	1.34	0.31	0.04	0.00	0.04
Annual Emissions (lb/yr)	67.16	15.74	1.84	0.12	2.10
Annual Emissions (tons/yr)	0.03	0.01	0.00	0.00	0.00

Notes:
(1) Based on default heat content for #2 diesel of 138,000 Btu/gal (from 40 CFR 98)
(2) emissions based on normal testing and maintenance hours 1 hour/day and 50 hours/year
(3) spreadsheet provided by applicants, reviewed, verified and approved by MDAQMD

Table 3.1B-5
Sonoran Energy Project
Emissions and Operating Parameters for Cooling Tower

Manufacturer	SPX/Marley
Model	F448A48A3.010A
Number of towers	1
Number of cells per tower	10
Fan stack diameter (ft)	28
Exhaust temperature (F)	79.00
Exhaust flow rate per cell (acfm)	1,359,101
Water Circulation Rate, gal/min	129,480
Drift Rate	0.0005%
Water Drift (lbs/hr)	323.57
TDS Level, mg/L	5000
Emissions	
PM10 lb/hr	1.62
PM10 lb/day	38.90
PM10 tpy	7.10
PM10 emissions per cell, lb/hr	0.162
PM10 emissions per cell, g/s	0.020

	Nox		Sox		CO		VOC		PM10			NH3
	lb/day	ton/year	lb/day	ton/year	lb/day	ton/year	lb/day	ton/year	lb/day	ton/year		ton/year
BEP												
CT1												
CT2												
EICE FP												
Cooling Tower - main												
Cooing Tower - chiller												
FACILITY		97		12		97		24		56.9		
	Nox		Sox		CO		VOC		PM10			NH3
	lb/day	ton/year	lb/day	ton/year	lb/day	ton/year	lb/day	ton/year	lb/day	ton/year		ton/year
SEP												
CTG	879.95	84.77	117.63	8.65	887.42	68.54	281.10	26.66	238.23	31.40		84.50
Aux Boiler	19.12	2.24	2.19	0.16	97.01	10.43	8.33	1.06	11.13	1.62		
EICE FP	1.34	0.03	0.00	0.0001	0.31	0.01	0.04	0.00	0.04	0.00		
Cooling Tower									38.90	7.10		
Facility	900.42	87.0	119.82	8.8	984.75	78.97	289.47	27.7	288.3	40.1		84.50
Application Package	922.4	**85.6**	120.0	**8.8**	986.0	**78.0**	286.8	**24.2**	289.3	**40.1**		**81.7**
*Bolded values indicate limits set by permit conditions.												

Facility emissions are limited to the ton/year values requested by the applicant.

Pollutant	BEP TURBINES ONLY (1)	SEP TURBINE ONLY (1)	Total Emissions BEP + SEP TURBINES TPY (1)		
Ammonia	213.86	81.74	295.59		
Propylene	6.08	4.74	10.82		
HAZARDOUS AIR POLLUTANTS - FEDERAL					
Acetaldehyde	0.32	0.25	0.57		
Acrolein	0.05	0.04	0.09		
Benzene	0.10	0.07	0.17		
1,3-Butadiene	0.00	0.00	0.01		
Ethylbenzene	0.25	0.20	0.45		
Formaldehyde	7.17	5.59	**12.76**	**MAJOR HAP SOURCE**	
Hexane, n-	2.02	1.58	3.60		
Naphthalene	0.01	0.01	0.02		
Total PAHs (listed individually below)	0.01	0.00	0.01		
Acenaphthene	0.00	0.00	0.00		
Acenapthylene	0.00	0.00	0.00		
Anthracene	0.00	0.00	0.00		
Benzo(a)anthracene	0.00	0.00	0.00		
Benzo(a)pyrene	0.00	0.00	0.00		
Benzo(e)pyrene	0.00	0.00	0.00		
Benzo(b)fluoranthrene	0.00	0.00	0.00		
Benzo(k)fluoranthrene	0.00	0.00	0.00		
Benzo(g,h,i)perylene	0.00	0.00	0.00		
Chrysene	0.00	0.00	0.00		
Dibenz(a,h)anthracene	0.00	0.00	0.00		
Fluoranthene	0.00	0.00	0.00		
Fluorene	0.00	0.00	0.00		
Indeno(1,2,3-cd)pyrene	0.00	0.00	0.00		
Phenanthrene	0.00	0.00	0.00		
Pyrene	0.00	0.00	0.00		
Propylene oxide	0.23	0.18	0.41		
Toluene	1.04	0.81	1.85		
Xylene	0.51	0.40	0.91		
TOTAL	11.71	9.14	20.85		
1. Emissions units also include internal combustion engines, cooling towers and a boiler. The turbines are the main HAP source.					

Best Available Control Technology

Best Available Control Technology (BACT) is required for any new or modified facility that emits, or has the potential to emit, 25 tons per year or more of any non-attainment pollutant or its precursors or any new or modified permit units which emit or have the potential to emit 25 pounds per day or more of any non-attainment pollutant or its precursors (MDAQMD Rule 1303(A)). BACT is applied on a pollutant specific basis, meaning it is required by rule only for each non-attainment air pollutant with emissions over the threshold specified in Rule 1303.

The project location designations are as follows:

	NO2	Ozone	SO2	PM10	CO
Federal Status	Unclassified/ Attainment	Unclassified/ Attainment	Unclassified/ Attainment	Unclassified	Unclassified/ Attainment
State Status	**Attainment**	**Non-attainment**	Attainment	**Non-attainment**	Unclassified

BACT applicability on the basis of Rule 1303(A)(3), non-attainment air pollutant, facility emissions over 25 tons per year:

	NOx (ozone precursor)	VOC (ozone precursor)	SOX (PM10 precursor)	PM10
Threshold TPY	25	25	25	25
FACILITY	**182.6**	**48.3**	20.8	**97**

BACT applicability on the basis of Rule 1303(A)(1), non-attainment air pollutant, new emission unit, emissions over 25 lb/day:

	NOx (ozone precursor)	VOC (ozone precursor)	SOX (PM10 precursor)	PM10
Threshold LB/DAY	25	25	25	25
CTG	**871**	**278**	**118**	**238**
Aux Boiler (corrected to 3% oxygen)	16.3	7.5	2.2	11.1
EICE	**32.2**	0.9	0.003	0.004
Cooling Tower	0	0	0	**38.9**

All concentration levels presented in the following BACT determinations are corrected to 15% oxygen, unless otherwise specified.

Based on the proposed project's maximum emissions as summarized above, BACT applies and is required as follows:

	NOx	VOC	SOX	PM10	BASIS
CTG	X	X	X	X	1303(A)(1) 1303(A)(3)
Aux Boiler	X	X		X	1303(A)(3)
EICE	X	X		X	1303(A)(3)
Cooling Tower				X	1303(A)(1) 1303(A)(3)

The District reviewed the following sources to determine current BACT for natural gas fired combustion turbines:

- Similar projects recently granted Licenses by the CEC
- BAAQMD BACT Guidelines
- SCAQMD BACT Guidelines
- SJVAPCD BACT Guidelines
- USEPA RACT/BACT/LAER Clearinghouse
- CARB BACT Clearinghouse

BACT – CTG: NOx, VOC, SOX. PM10

NOx

NOx is a precursor of ozone and PM10, and both ozone and PM10 are state non-attainment pollutants at the proposed facility location. NOx will be formed by the oxidation of atmospheric nitrogen during combustion within the gas turbine generating systems.

The SEP proposes 2.0 ppmvd averaged over one hour, 1.5 ppmvd annual average with an ammonia slip of 5 ppmvd. The District determines that the proposed technology low-NOx burners and selective catalytic reduction in the presence of ammonia is acceptable as NOx BACT for the SEP combined cycle gas turbine.

VOC and Trace Organic BACT

VOC is a precursor for ozone and PM10, which are state non-attainment pollutants at the proposed facility location. VOCs and trace organics are emitted from natural gas-fired turbines as a result of incomplete combustion of fuel and trace organics contained in pipeline-quality natural gas.

The most stringent VOC control level for gas turbines has been achieved by those which employ catalytic oxidation for CO control. An oxidation catalyst designed to control CO would provide a side benefit of controlling VOC emissions. CARB guidance suggests that a 2 ppmvd averaged over three hours VOC emissions limit is VOC BACT. The District determined that a maximum VOC concentration of 1 ppmvd averaged over one hour was VOC BACT for the High Desert Power Project (achieved through the use of an oxidation catalyst optimized for VOC control).

The BEP proposes a VOC emission limit of 1.0 ppmvd (2.0 ppmvd with duct firing) averaged over one hours as VOC BACT, achieved with combustion controls. The District has determined that the proposed emission limits are acceptable as VOC BACT for the SEP combined cycle gas turbine.

PM10

PM10 is a state non-attainment pollutant at the proposed facility location. Particulate will be emitted by the gas turbine generating systems due to fuel sulfur, inert trace contaminants, mercaptans in the fuel, dust drawn in from the ambient air and particulate of carbon, metals worn from the equipment while in operation, and hydrocarbons resulting from incomplete combustion. The most stringent particulate control method for gas turbines is the use of low ash fuels such as natural gas. No add-on control technologies are listed in the EPA BACT/LAER Clearinghouse listing provided by the applicant. There have not been any add-on particulate control systems developed for gas turbines from the promulgation of the first New Source Performance Standard for Stationary Turbines (40 CFR 60 Subpart GG, commencing with §60.330) in 1979 to the present. The cost of installing such a device has been and continues to be prohibitive and performance standards for particulate control of stationary gas turbines have not been proposed or promulgated by EPA. Combustion control and the use of low or zero ash fuel (such as natural gas) is the predominant control method listed for turbines with PM limits. CARB guidance suggests a requirement to burn natural gas fuel with sulfur content not greater than 1 grain/100 scf is PM10 BACT. The District determined that sole use of natural gas as fuel was PM10 BACT for the High Desert Power Project. The SEP proposes the sole use of natural gas with an annual average sulfur content not greater than 0.25 grains/100 scf and a 24-hour average sulfur content not greater than 0.5 grains/100 scf as PM10 BACT.

The District therefore determines that the sole use of natural gas fuel with a fuel sulfur content not greater than 0.25 grains/100 scf on an annual average basis and not greater than 0.5 grains/100 scf on a daily average basis is acceptable as PM10 BACT for the combined cycle gas turbine.

SOx

SOx is a precursor to PM10, a non-attainment pollutant at the proposed facility location. SOx is exclusively formed through the oxidation of sulfur present in the fuel. The emission rate is a function of the efficiency of the source and the sulfur content of the fuel, since virtually all fuel sulfur is converted to SOx. CARB guidance suggests that a requirement to burn natural gas with a fuel sulfur content not greater than 1 grain/100 scf is SOx BACT. The District determined that sole use of natural gas with a fuel sulfur content not greater than 0.2 grains per 100 scf as fuel was SOx BACT for the High Desert Power Project. Pipeline quality natural gas regulated by the California Public Utilities Commission typically must meet one grain per 100 scf. The District will limit fuel sulfur content by permit condition.

The District determines that the exclusive use of natural gas fuel with not greater than 0.25 grains/100 scf on an annual average basis and not greater than 0.5 grains/100 scf on a daily average basis is acceptable as SOx BACT for the BEP combined cycle gas turbines.

CTG

	Technology	Achieved in Practice BACT	Limit
NOx	SCR	2.0 ppm, Dry @ 15% O2	2 ppmvd (1 hour average) corrected to 15% O2 1.5 ppmvd (annual average) corrected to 15% O2
VOC	good combustion practices and oxidation catalyst	2.0 ppm, Dry @ 15%O2	2 ppmvd with duct firing (1 hour average) corrected to 15% O2 1 ppmvd without duct firing (1 hour average) corrected to 15% O2
PM10	fuel choice: natural gas	Natural Gas Fuel (sulfur content not to exceed 1.0 grain/100 scf)	10 lb/hr with duct firing 8 lb/hr no duct firing
SOx	fuel choice: natural gas	Natural Gas Fuel (sulfur content not to exceed 1.0 grain/100 scf)	4.9 lb/hr with duct firing 4.6 lb/hr no duct firing

The District finds that the control technology proposed by the applicant meets current achieved in practice BACT.

T-BACT – CTG

trace organic VOC	oxidation catalyst	4.0 ppm, Dry @15% O2	2 ppmvd with duct firing(1 hour average) corrected to 15% O2 1 ppmvd without duct firing (1 hour average) corrected to 15% O2

Rule 1320(B) requires that new or modified emission units are subject to State NSR for toxics if those units have the potential to emit any Toxic Air Contaminants and are subject to Federal NSR for toxics if the facility is a major source of Hazardous Air Pollutants. The proposed SEP emission units do have the potential to emit TAC and the facility is a major HAP source (formaldehyde) therefore the project is subject to both State and Federal T-NSR. Pursuant to the rule's, all applicable MACT standards have been applied to the new permit units satisfying the Federal T-NSR requirements. State T-NSR requires that all applicable Airborne Toxic Control Measures are applied and those requirements have been added by permit condition. State T-NSR also requires that an analysis of the potential health risk associated with the TAC emissions from the proposed project. The applicant conducted a Health Risk Assessment in compliance with Rule 1320. The HRA has been discussed in greater detail on page 18 of this document. The results of the HRA indicate that SEP as proposed is a Moderate Risk but less than a Significant Health Risk [1320(E)(3)(e)(ii)] therefore the District is required to add requirements to the permits which ensure that T-BACT is applied. The District has required that ammonia slip associated with the combustion turbine is limited to 5 ppmvd and has limited ammonia emissions appropriately by permit condition. Further, all applicable ATCM and MACT requirements have been added which include:

- 17 CCR 93115 Airborne Toxic Control Measure for Stationary Compression Ignition Engines
- 40 CFR 63 Subpart ZZZZ - National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
- 40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
- 40 CFR 63 Subpart YYYY - National Emission Standard for Hazardous Air Pollutants for Stationary Combustion Turbines

BACT – AUXILIARY BOILER: NOx, VOC, PM10

Emissions from the natural gas fired boiler include NOx, VOC, SOx, CO, PM10 and toxics. BACT is required for NOx, VOC and PM10. The applicant proposes the following as NOx, VOC and PM10 BACT for the boiler:

	Technology	Achieved in Practice BACT	Proposed Limit
NOx	ultra-low NOx burner	9 ppmvd	7 ppmvd at 3% O2
VOC	good combustion practices		10 ppmvd at 3% O2
PM10	fuel choice: natural gas		0.5 lb/hr
SOx	fuel choice: natural gas		1.26 ppmvd at 3% O2 based on 0.5 gr/100 dscf sulfur content of fuel
CO	Good combustion practices and flue gas recirculation	50 ppmvd	50 ppmvd at 3% O2

The District has determined that the proposed equipment meets BACT as achieved in practice for this class and category of equipment.

BACT – EMERGENCY DIESEL FIRED INTERNAL COMBUSTION ENGINE, FIRE PUMP: NOx, VOC, PM10

Emissions from diesel fired emergency engine will include NOx, VOC, SOx, CO, PM10 and toxics. BACT is required for NOx, VOC and PM10. The applicant proposes a Tier III certified engine as emergency engine BACT.

	Technology	Limit
NOx + NMHC	Turbocharging/intercooling, Tier III certified engine	3.0 g/bhp-hr
PM10		0.15 g/bhp-hr
SOx		0.01 g/bhp-hr
CO		0.60 g/bhp-hr

The District determines that compliance with Title 17 CCR §93115 Airborne Toxic Control Measure which requires the Tier III standard for new fire pump engines is acceptable as BACT for NOx, VOC and PM10 for the proposed emergency fire pump engine.

BACT – COOLING TOWER: PM10

Particulate will be emitted by the cooling towers through evaporation and particulate mist entrainment. The applicant proposes mist eliminators as cooling tower BACT.

Proposed Limits for Cooling Towers	
Pollutant	Control
PM	Drift rate not to exceed 0.0005%
NO_x, SO_x, CO, VOC	Not Applicable

The District has determined that high efficiency mist eliminators limiting drift to 0.0005 percent is acceptable as PM10 BACT for the SEP cooling tower.

Class I Area Visibility Protection

The applicant EPA has indicated that SEP facility emissions are below the PSD threshold for all attainment/unclassified criteria pollutants. A Class I Area Visibility Protection is not required.

Alternative Siting Analysis

An Alternative Siting Analysis was conducted as required by Rule 1302. The analysis addressed alternative locations, alternative generation technologies and a "no project" alternative scenario. SEP will share infrastructure with the existing BEP therefore, locating the project at an alternative site would require construction to interconnect the two plants which would cause additional impacts from mobile sources. Alternative sites were determined to cause additional environmental impacts and so were determined to be unsuitable. Alternative power generation technologies were evaluated and found to be unsuitable. The SEP site is the same site as the BEP II site and is not of sufficient size to allow for solar or wind generating technologies to satisfy the project objective to generate 553 MW. Likewise, the site does not contain the resources necessary for geothermal, biomass, or hydroelectricity. The "no project" alternative was evaluated and dismissed because should the plant not be built, the required power would be generated by older, less efficient plants which would result in greater environmental impact than those that would result from the construction and operation of SEP.

Offset Requirements

MDAQMD Regulation XIII – *New Source Review* requires offsets for non-attainment pollutants and their precursors for facilities and equipment having emissions which exceed the threshold specified in the rule. The applicant has prepared and submitted a proposed offset strategy for the proposed project as required by Rule 1302(C)(3)(b). The project is proposed for a location that has been designated non-attainment for the State ozone and PM_{10} ambient air quality standards. MDAQMD Rule 1303(B)(1) specifies offset threshold amounts. MDAQMD Rule 1303(B)(1) also specifies offset threshold amounts for precursors of non-attainment pollutants: NO_x (precursor of ozone and PM_{10}), SO_x (precursor of PM_{10}), and VOC (precursor of ozone and PM_{10}). A new or modified facility which emits or has the potential to emit more than these offset thresholds must obtain offsets in the amounts specified by Rule 1305(A).

Effect of Modification:

Rule 1305(A)(2)(b)(ii)(b)(ii) applies to the facility VOC emissions because SEP constitutes a modification of the existing BEP which is a non-major source of VOC which will become a major source and is located within an area which is unclassified/attainment for the ozone National Ambient Air Quality Standards (NAAQS). Pursuant to the rule, VOC emissions in excess of 25 tons/year from the facility which includes both BEP and SEP must be offset. Rule 1305(A)(2)(b)(iii) applies to the facility NOx and PM10 emissions because BEP is an existing major source of NOx and PM10. Pursuant to the rule, NOx and PM10 emissions in excess of the previously offset PTE must be offset.

Simultaneous Emission Reductions:

BEP has proposed to reduce the existing emissions limits for SOx and PM10. The reduced SOx and PM10 emissions at BEP are proposed for use as Simultaneous Emission Reductions and applied to the emissions increase produced by the modification which adds SEP. There is no net increase for PM10 or SOx. There are net increases for NOx and VOC therefore offsets are required for VOC emissions in excess of the threshold and for NOx emissions in excess of the previously offset facility emissions cap. The facility is in an area designated attainment/unclassified for ozone therefore pursuant to Rule 1305(C) the offset ratio for NOx and VOC is 1:1.

Comparison of SEP Emissions with Offset Thresholds				
All emissions in tons per year				
	NO_x	**VOC**	**SO_x**	**PM_{10}**
Offset Threshold	25	25	25	15
Existing BEP	97	24	24	97
BEP Proposed Reduced Emission Limits [a]	97	24	12	56
New Emissions SEP	85.6	24.3	8.8	40.1
Maximum Facility Emissions (BEP + SEP)	182.6	48.3	20.8	97
Net Change	85.6	24.3	-3.2	0
Offset Burden	**85.6**	**23.3**	**0**	**0**
(a) PDOC addressing SERs at BEP issued 12/18/15				

The emissions in the table above represent maximum or worst-case annual emissions. The table also includes all applicable emissions, including the emissions increases from proposed new permit units (turbines, duct burners, SCR and wet cooling equipment), cargo carriers (none are proposed), fugitive emissions (none are proposed), and non-permitted equipment (none are proposed). For this analysis the MDAQMD assumes VOC is equivalent to ROC and SO_2 is equivalent to SO_x. Note that some fraction of sulfur compounds are included in both the SO_x and the PM_{10} totals, as the PM_{10} total includes front and back half particulate.

Identified Emission Reduction Credits

APHUS owns 200 tons of NOx emission reduction credits (MDAQMD certificate #0099) which BEP has identified several sources of emission reduction credits (ERCs). The NOx ERCs were generated by the replacement of eleven natural gas-fired internal combustion engine driven natural gas generators and natural gas compressors with six functionally identical replacement IC engines equipped with the latest control technology. The reduction occurred at a Southern California Gas Company facility located in Blythe. Rule 1305(C)(4) requires that the District adjust offsets proposed for use to reflect any emission reductions in excess of Reasonable Available Control Technology (RACT) at the time of use. The Southern California Gas replacement engines comply with the requirements of 40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. District Rule 1160 – Internal Combustion Engines does not apply outside the Federal Ozone Non-attainment area. The District finds that the emission reduction credits resulting from the engine replacements meet current RACT and do not require adjustment at this time.

Inter-Pollutant Offsetting

SEP has proposed to offset both NOx and VOC emissions with NOx ERCs. The use of inter-district, inter-air basin and inter-pollutant offsets is specifically allowed for by Rule 1305(B)(4) through (6) (in consultation with CARB and USEPA, and in the case of inter-pollutant offsets, with the approval of USEPA). The District therefore determines that this inter-pollutant trade is technically justified because NOx and VOC are both ozone precursors and that the inter-pollutant trade will not cause or contribute to a violation of the NO2 or ozone ambient air quality standards. As previously approved for BEPII (PDOC, May 3, 2004), pursuant to Rule 1305(C) the offset ratio for NOx and VOC is 1:1.

Air Quality Impact Analysis

Blythe is in an area which is unclassified/attainment with respect to the NAAQS for NO2, SO2, CO, PM10 and PM2.5. For projects where offsets are required, Rule 1302(C)(2)(b) requires demonstration that the project will not cause an exceedance of the NAAQS for pollutants which the area has been designated unclassified or attainment. The applicant performed the ambient air quality standard impact analyses for NO_2, SO_2, CO, PM_{10} and $PM_{2.5}$ emissions. The MDAQMD approves of the analysis methods used in these impact analyses and the findings of these impact analyses.

Inputs and Methods

surface meteorological data	Blythe monitoring station 2009 through 2013
upper air data	Elko Nevada National Weather Service Station 2009 through 2013
O3 background	Blythe 2009 through 2013
SO2 background	Victorville 2009 through 2013
NO2, CO, PM10, PM2.5 background	Palm Springs 2009 through 2013
SCREEN3	Version 96043
AERMOD	Version 14341 • Regulatory default option • OLM

NO2/NOx ratios	• Vendor data for turbine and boiler
	  • Turbine, normal 13%
	  • Turbine, SUSD 24%
	  • Turbine, commissioning 24%
	  • Boiler, normal 29%
	  • Boiler, <25% load 12.5%
	• Emergency fire pump 20%

The USEPA American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) dispersion model was used to estimate ambient concentrations resulting from the cumulative maximum emissions from BEP and SEP. Worst case impacts were evaluated using a screening model which provided the operating mode that yielded the maximum impact. The worst case operating full hour scenario, 100% load with duct firing with no start up shut down events, was then used to calculate emissions which were then subjected to detailed dispersion modeling. The applicant also evaluated short-term NO2 and CO impacts under startup and initial commissioning conditions when emissions are uncontrolled. The District has reviewed the analysis and approves of the methods used and the resulting findings.

Findings

The impact analysis calculated the maximum emissions for each pollutant for each applicable averaging period, as shown in the table below. When added to the maximum recent background concentration (2011 through 2013), the SEP did not exceed the most stringent standard for any pollutant.

SEP Worst Case Ambient Air Quality Impacts					
	Project Impact	**Background**	**Total Impact**	**Federal Standard**	**State Standard**
Pollutant	*All values in $\mu g/m^3$*				
NO_2 (annual)	0.4	13.2	13.6	100	57
NO_2 (1 hour)	123.0	77.1	200.1		339
NO_2 (federal 1 hour)	64.9	77.1	142.0	188	
SO_2 (1 hour)	7.0	22.9	29.9		655
SO2 (federal 1 hour)	7.0	13.0	20.0	196	
SO_2 (3 hour)	3.4	22.6	26.0	1300	
SO_2 (24 hour)	1.0	2.6	3.6	365	105
CO (1 hour)	144.6	4,000.0	4144.6	40,000	23,000
CO (8 hour)	16.4	1,698.0	1714.4	10,000	10,000
PM_{10} (24 hour)	8.1	127.0	135.1	150	50
PM_{10} (annual)	0.9	22.1	23.0		20
$PM_{2.5}$ (24 hour)	8.1	13.8	21.9	35	
$PM_{2.5}$ (annual)	0.9	6.5	7.4	15	12

Health Risk Assessment

SEP performed a Health Risk Assessment (HRA) for carcinogenic, non-carcinogenic chronic, and non-carcinogenic acute toxic air contaminants. Ammonia is a by-product of the selective catalytic reduction process, as some ammonia does not react and remains in the exhaust stream. As ammonia is not a regulated criteria air pollutant, but is a hazardous and toxic compound, the

District will address ammonia emissions as an element of the toxics and hazardous emissions analysis. Ammonia is further discussed on pages B-4 and B-5 as an element of T-BACT.

Inputs and Methods

surface meteorological data	Blythe monitoring station 2009 through 2013
upper air data	Elko Nevada National Weather Service Station 2009 through 2013
SCREEN3 – worst case operating scenario	Version 96043
AERMOD – GLC based on worst case operating scenario	Version 14341 • Regulatory default option
Risk associated with GLC	• HARP2 with most current (5/15) health database • OEHHA Hot Spots Program Manual (2015)
Emission Factors	• CATEF • AP-42 • VCAPCD (boiler) • well water concentration estimates (cooling tower)

The BEP will emit toxic air contaminants as products of natural gas combustion, equipment wear, ammonia slip from the SCR systems, and cooling tower emissions. Ammonia slip will be limited to be 5 ppm in the stack exhaust.

Findings

The HRA calculated peak cancer risk for both residential and worker receptors. The 30-year residential cancer risk was 1.3 in one million while the 25 year worker cancer risk was 0.09 in one million. The maximum cancer risk at any residential location is 0.07 in one million. The maximum non-cancer chronic and acute Health Hazard Indices are both less than the significance level of 1.0. The MICR classified the proposed project as "Moderate Risk" therefore pursuant to Rule 1320(F)(3)(e)(ii), T-BACT must be applied – see T-BACT discussion pages B-4 through B-5.

	Cancer Risk	Acute Health Hazard Index	Chronic Health Hazard Index 8 Hr
MICR	1.3	0.024	0.0015
MEIR	0.07	0.0050	0.0003
MEIW	0.09	0.0050	0.0003

Applicable Regulations and Compliance Analysis

Selected MDAQMD Rules and Regulations will apply to the proposed project:

Regulation II – Permits

Rule 221 – *Federal Operating Permit Requirements* requires certain facilities to obtain Federal Operating Permits. The proposed project will be required to submit an application for a federal operating permit within twelve months of the commencement of operations.

Regulation IV - Prohibitions

Rule 401 – *Visible Emissions* limits visible emissions opacity to less than 20 percent (or Ringelmann No. 1). During start up, visible emissions may exceed 20 percent opacity but shall not exceed 20% opacity for longer than three minutes in any one hour. In normal operating mode, visible emissions are not expected to exceed 20 percent opacity.

Rule 402 – *Nuisance* prohibits facility emissions that cause a public nuisance. The proposed turbine power train exhaust is not expected to generate a public nuisance due to the sole use of pipeline-quality natural gas as a fuel. In addition, due to the location of the proposed project, no nuisance complaints are expected.

Rule 403 – *Fugitive Dust* specifies requirements for controlling fugitive dust. The proposed project does not include any significant sources of fugitive dust so the proposed project is not expected to violate Rule 403.

Rule 403.2 – *Fugitive Dust Control for the Mojave Desert Planning Area* specifies requirements for construction projects. The construction of the proposed project will be required to comply with the requirements of Rule 403.2.

Rule 404 – *Particulate Matter – Concentration* specifies standards of emissions for particulate matter concentrations. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 404.

CTG

	dscf/min	limit gr/dscf	concentration	
Rule 404	1,191,573	0.0122	0.0007	COMPLIES

Boiler

	dscf/min	limit gr/dscf	concentration	
Rule 404	10,958	0.073	0.005	COMPLIES

Fire Pump

	dscf/min	limit gr/dscf	concentration	
Rule 404	1513	0.158	0.00	COMPLIES

Cooling Tower

	dscf/min	limit gr/dscf	concentration	
Rule 404	13591010	0.01	0.0000	COMPLIES

Rule 405 – *Solid Particulate Matter - Weight* limits particulate matter emissions from fuel combustion on a mass per unit combusted basis. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 405.

CTG

	lb/hr	limit lb/hr	lb/hr PM10	
Rule 405	171713.32	18.9	9.9264	COMPLIES

Boiler

	lb/min	limit lb/hr	lb/hr PM10	
Rule 405	3198	6.95	0.46	COMPLIES

Fire Pump

	lb/min	limit lb/hr	lb/hr PM10	
Rule 405	80.73	0.99	0.0420	COMPLIES

Cooling Tower

	lb/hr	limit lb/hr	lb/hr PM10	
Rule 405	64714104	30	1.6208	COMPLIES

Rule 406 – *Specific Contaminants* limits sulfur dioxide emissions. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 406.

Rule 408 – *Circumvention* prohibits hidden or secondary rule violations. The proposed project is not expected to violate Rule 408.

Rule 409 – *Combustion Contaminants* limits total particulate emissions on a density basis. The sole use of pipeline-quality natural gas a fuel will keep proposed project emission levels in compliance with Rule 409.

CTG

	dscf/min	limit gr/dscf	concentration	
Rule 409	2,798,187	0.1	0.0003	COMPLIES

Boiler

	dscf/min	limit gr/dscf	concentration	
Rule 409	25733.7112	0.1	0.00	COMPLIES

Fire Pump

	dscf/min	limit gr/dscf	concentration	
Rule 409	1513	0.1	0.00	COMPLIES

Rule 430 – *Breakdown Provisions* requires the reporting of breakdowns and excess emissions. The proposed project will be required to comply with Rule 430 by permit condition.

Rule 431 – *Sulfur Content in Fuels* limits sulfur content in gaseous, liquid and solid fuels. The sole use of pipeline-quality natural gas a fuel will keep the proposed project in compliance with Rule 431.

Rule 475 – *Electric Power Generating Equipment* limits NO_x and particulate matter emissions with mass rate and concentration standards. Permit conditions for the proposed project will establish limits which are in compliance with Rule 475.

Regulation IX – Standards of Performance for New Stationary Sources

<u>40 CFR 60 Subpart TTTT</u> - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units
Applies to natural gas stationary combustion turbines that satisfy all of the following criteria:

- Commence construction after Jan 8, 2014;
- Design heat input capacity > 73 MW;
- More than 90% natural gas fuel combustion (average annual heat input) on a 3-year rolling average basis;
- Constructed for the purpose of supplying, and supplies: at least one-third of its potential electric output; AND more than 219,000 MWh net-electrical output on a 3-year rolling average basis.

Newly Constructed and Reconstructed Fossil Fuel Fired Stationary Combustion Turbines	Efficient NGCC technology for base load natural gas fired units and clean fuels for non-base load and multi-fuel-fired units	1. 1,000 lb CO2/MWh-g or 1,030 lb CO2/MWh-n for base load natural gas-fired units. 2. 120 lb CO2/MMBtu for non-base load natural gas-fired units. 3. 120 to 160 lb CO2/MMBtu for multifuel-fired units.

The CTG is subject to this NSPS, permit conditions have been added to the CTG permit to ensure compliance with the CO2 limits for base load natural gas-fired units.

40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines
This NSPS is applicable to stationary gas turbines with a heat input at peak load equal to or greater than 10 million Btu per hour, based on the lower heating value of the fuel fired which commenced construction after October 3, 1977. Because 40 CFR 60 Subpart KKKK applies pursuant to §63.4305(b), the requirements of this NSPS do not apply.

40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
This NSPS is applicable to the CTG because it is a stationary combustion turbine with a heat input at peak load equal to or greater than 10 MMBtu per hour, based on the higher heating value of the fuel, and commenced construction after February 18, 2005

NOx	§60.4320	New, modified, or reconstructed turbine firing natural gas 850 MMBtu/h	15 ppm at 15 percent O2	Proposed equipment at 2 ppm emission concentration complies with the limit.
SO2	§60.4330	turbines located in a continental area	You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output	Proposed equipment is rated at 543 MW and SO2 emissions from the turbine are 4.9 lb/hr. The proposed turbine potential emissions of SO2 are 0.009 lb/MW-hr which complies with the limit.

The turbine will be equipped with a CEMS which will monitor NOx emissions as required by §60.4340. The facility will be required to develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment used to demonstrate compliance with the NSPS. The facility will demonstrate that the potential sulfur emissions comply with the specified limit as provided in §60.4365.

40 CFR 60 Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
This NSPS applies to the auxiliary boiler because it is a steam generating unit that commenced construction after June 9, 1989 and the maximum rating is less than 100 MMBtu/hr and greater than 10 MMBtu/hr. Permit conditions have been added to the auxiliary boiler permit to ensure compliance.

40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
This NSPS applies to compression ignited internal combustion engines which commenced construction after July 11, 2005. This regulation is applicable to the engine powering the fire pump at SEP. Pursuant to §60.202, the engine must meet the standards in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants which the proposed engine does. Permit conditions have been added to the engine permit to ensure compliance with all applicable regulations.

Title 17 CCR 93115 – Airborne Toxic Control Measure for Stationary Compression Ignition Engines
This regulation applies to stationary diesel fired internal combustion engines over 50 horsepower and is applicable to the engine powering the fire pump. Pursuant to §93115.6(a)(4), new stationary emergency standby direct-drive fire pump engines greater than 50 BHP must meet the Tier III standards. The proposed engine complies with the Tier III standards. Permit conditions have been added to the engine permit to ensure compliance with all applicable regulations.

Regulation X – Emission Standards for Additional Specific Air Contaminants

Rule 1000 - National Emission Standards for Hazardous Air Pollutants (NESHAP) applies to the owner or operator of any stationary source for which a standard is prescribed in any National Emissions Standards for Hazardous Air Pollutants as set forth in 40 Code of Federal Regulations, Part 61 (40 CFR 61).

40 CFR 63 Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units
This NESHAP does not apply because the EGU is not fueled with coal or oil.

40 CFR 63 Subpart YYYY - National Emission Standard for Hazardous Air Pollutants for Stationary Combustion Turbines
This NESHAP applies as the EGU is greater than 1.0 MW and located at a major source of HAP. On Aug 18, 2004, EPA stayed the effectiveness of the emission and operating limitations for lean-premixed gas-fired and diffusion flame gas-fired turbines. These turbines must comply only with the Initial Notification requirements in 63.6145 until EPA takes final action on the stay. See the Federal Register document below.

40 CFR 63 Subpart ZZZZ - National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
This NESHAP applies to stationary reciprocating internal combustion engines operated at major and area sources. SEP is a major source of HAP therefore this regulation applies to the internal combustion engine powering the facility's fire pump. Pursuant to §63.6590(c)(7), the engine complies with the NESHAP by complying with 40 CFR 60 Subpart IIII.

40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

This NESHAP applies to industrial boilers and process heaters at major sources of HAP and applies to the proposed auxiliary boiler. Because the boiler will be fired on pipeline quality natural gas, there are no emission limits required by the NESHAP. The boiler will be required to be tuned annually in accordance with the criteria set forth in the NESHAP.

Regulation XII – Federal Operating Permits

Regulation XII contains requirements for sources which must have a federal operating permit and an acid rain permit. The applicant has submitted applications for a federal operating permit and an acid rain permit proposed project.

Regulation XIII – New Source Review

Rule 1300 – *General* specifies the requirements for pre-construction review and permitting of new and modified sources of pollutants for which criteria have been established in accordance with Section 108 of the Federal Clean Air Act. Mandated by Title I of the Federal Clean Air Act and implemented by 40 CFR Parts 51 and 52. There are additional NSR requirements mandated by the California Clean Air Act.

Rule 1302 – *Procedure* requires certification of compliance with the Federal Clean Air Act, applicable implementation plans, and all applicable MDAQMD rules and regulations. The ATC application package for the proposed project includes sufficient documentation to comply with Rule 1302(D)(5)(b)(iii). Permit conditions for the proposed project will require compliance with Rule 1302(D)(5)(b)(iv).

Rule 1303 – *Requirements* requires BACT and offsets for selected large new sources. Permit conditions will limit the emissions from the proposed project to a level which has been defined as BACT for the proposed project, bringing the proposed project into compliance with Rule 1302(A). Prior to the commencement of construction the proposed project shall have obtained sufficient offsets to comply with Rule 1303(B)(1).

Rule 1306 – *Electric Energy Generating Facilities* places additional administrative requirements on projects involving approval by the California Energy Commission (CEC). The proposed project will not receive an ATC without CEC's approval of their Application for Certification, ensuring compliance with Rule 1306.

Rule 1320 - *NSR for Toxic Air Contaminants* provides for the preconstruction review of all new, Modified Relocated or Reconstructed Facilities which emits or have the potential to emit any Hazardous Air Pollutants, Toxic Air Contaminants or Regulated Toxic Substances. See T-BACT discussion page B-5.

Rule 1520 - *Control of Toxic Air Contaminants from Existing Sources* ensures that new or existing Facilities are required to control the emissions of Toxic Air Contaminants or Regulated Toxic Substances. Only SEP TAC emissions were included in the HRA. Although BEP and SEP are considered one stationary source, because the MICR was less than 10 and the HI less than 1 for the new permit units, the new permit units are not considered a significant health risk therefore the applicant is not required to include BEP emissions pursuant to 1520(D)(3)(ii).

Maximum Achievable Control Technology Standards

Health & Safety Code §39658(b)(1) states that when USEPA adopts a standard for a toxic air contaminant pursuant to §112 of the Federal Clean Air Act (42 USC §7412), such standard becomes the Airborne Toxic Control Measure (ATCM) for the toxic air contaminant. Once an ATCM has been adopted it becomes enforceable by the MDAQMD 120 days after adoption or implementation (Health & Safety Code §39666(d)). USEPA has adopted a Maximum Achievable Control Technology (MACT) standard that is applicable to the auxiliary boiler and turbine permit conditions have been included in the permit to ensure compliance with the MACT, please see T-BACT discussion pages B-4 and B-5.

Major sources are expected to meet a standard for Maximum Achievable Control Technology (MACT). The combined formaldehyde emissions from BEP and SEP exceed 10 tons therefore the single stationary source (BEP and SEP combined) are a major source of toxic air contaminants, therefore applicable MACT is required.

40 CFR 98 – Mandatory Greenhouse Gas Reporting - sources that in general emit 25,000 metric tons or more of carbon dioxide equivalent per year in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP) and the proposed project is required to report the annual CO2e emissions because they have the PTE over the 25,000 metric ton threshold. Permit conditions have been added to specify compliance with the reporting requirements.

Conclusion

The MDAQMD has reviewed the proposed project's Application for New Source Review and supplementary information. The MDAQMD has determined that the proposed project with the permit conditions (including BACT requirements) specified below, will comply with all applicable MDAQMD Rules and Regulations. This PDOC will be released for review and public comment and publicly noticed on or after December 18, 2015. This document shall be sent to CARB/EPA on the same date that the public notice is published. Written comments will be accepted for thirty days from the date of publication of the public notice. A Final Determination of Compliance shall be prepared no later than thirty days after the end of the public comment period.

Please forward any comments on this document to:

Eldon Heaston
Executive Director
Mojave Desert Air Quality Management District
14306 Park Avenue
Victorville, CA 92392-2310

Permit Conditions

The following permit conditions will be placed on the Authorities to Construct for the project.

Combustion Turbine Authority to Construct Conditions

3320 MMBtu/hr Natural Gas Fired GE 7HA.02 Gas Turbine Generator, Permit Number: BXXXXX

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf on a twenty-four hour basis and not exceeding 0.25 grains per 100 dscf on a rolling twelve month average basis, and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.
   [District Rule 1303(B); District Rule 431; District Rule 204, 40 CFR 60 Subpart KKKK §60.4365]

3. This equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and KKKK(Standards of Performance for Stationary Combustion Turbines) and TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units). This equipment is also subject to 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting, Federal Acid Rain (Title IV) and Federal Operating Permit (Title V) programs. Compliance with all applicable provisions of these regulations is required. In the event of a conflict between these conditions, State and Federal regulations, the more stringent requirements shall govern.

4. Emissions from this equipment (including its associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NO_x and VOC during periods of startup, shutdown and malfunction and during the commissioning period as defined in this permit:
   a. Hourly rates, computed every 15 minutes, verified by CEMS and annual compliance tests:
      i. NO_x as NO_2 – 26.0 lb/hr (based on 2.0 ppmvd corrected to 15% O_2 and averaged over one hour)
      ii. CO – 16.2 lb/hr (based on 2.0 corrected to 15% O_2 and averaged over 1 hour)
      iii. NH3 – 5 ppmvd (corrected to 15% O_2 and averaged over 1 hour)
   b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:
      i. VOC as CH_4 – 9.3 lb/hr (based on 2.0 ppmvd with duct firing corrected to 15% O_2 and averaged over 1 hours)
      ii. VOC as CH_4 – 4.6 lb/hr (based on 1.0 ppmvd without duct firing corrected to 15% O_2 and averaged over 3 hours)
      iii. SO_x as SO_2 – 4.9 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
      iv. PM_{10} – 10.0 lb/hr

[Rule 1303]
[40 CFR 60 Subpart KKKK]

5. A CEMS shall be installed and operated to demonstrate compliance with the NOx emissions limit specified in 40 CFR 60 Subpart KKKK. A quality assurance plan shall be developed and kept on site and available pursuant to §60.4335.

6. Emissions of CO and NOx from this equipment, including the duct burner, may exceed the limits contained in Condition 4 during startup and shutdown periods as follows:
a. Startup shall be defined as the period beginning with ignition and lasting until the power block has reached operating permit limits. Cold startup means a startup when the power block has not been in operation during the preceding 72 hours. Hot startup means a startup when the power block has been in operation during the preceding 8 hours. Warm startup means a startup that is not a hot or cold startup. Shutdown shall be defined as the period beginning with the lowering of the power block from normal operating load and lasting until fuel flow is completely off and combustion has ceased.
b. During a cold startup emissions shall not exceed the following, verified by CEMS:
i. NOx – 187.5 lb
ii. CO – 134.0 lb
c. During a warm startup emissions shall not exceed the following, verified by CEMS:
i. NOx – 154.7 lb
ii. CO – 135.3 lb
d. During a hot startup emissions shall not exceed the following, verified by CEMS:
i. NOx – 113.9 lb
ii. CO – 133.3 lb
e. During a shutdown emissions shall not exceed the following, verified by CEMS:
i. NOx – 24.8 lb
ii. CO – 148.11 lb

7. Emissions from this equipment, including the duct burner, shall not exceed the following emission limits, based on a calendar day summary:
   a. NO_x – 880.0 lb/day, verified by CEMS
   b. CO – 887.4 lb/day, verified by CEMS
   c. VOC as CH_4 – 281.1 lb/day, verified by compliance tests and hours of operation
   d. SO_x as SO_2 – 117.6 lb/day, verified by fuel sulfur content and fuel use data
   e. PM_{10} – 238.2 lb/day, verified by compliance tests and hours of operation

8. Particulate emissions from this equipment shall not exceed an opacity equal to or greater than twenty percent (20%) for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor.
[Rule 401]

9. This equipment shall exhaust through a stack at a minimum height of 140 feet.
[Rule 1302(C)]

10. Except during the commissioning as defined, the owner/operator (o/o) shall not operate this equipment without the selective catalytic NO_x reduction system with valid District permit CXXXXX installed and fully functional.

11. Emissions of NO_x, CO, CO2, O2 and ammonia slip shall be monitored using a Continuous Emissions Monitoring System (CEMS). Turbine fuel consumption shall be monitored using a continuous monitoring system. Stack gas flow rate shall be monitored using a Continuous Emission Rate Monitoring System (CERMS). The operator shall install, calibrate, maintain, and operate these monitoring systems according to a District-approved monitoring plan and MDAQMD Rule 218, and they shall be installed prior to initial equipment startup. The continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the accuracy requirement for startups and shutdowns specified in Condition 15. If accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits in this permit.Six (6) months prior to installation the operator shall submit a monitoring plan for District review and approval.

[40 CFR 98]

12. The o/o shall conduct all required compliance/certification tests in accordance with a District-approved test plan. Thirty (30) days prior to the compliance/certification tests the operator shall provide a written test plan for District review and approval. Written notice of the compliance/certification test shall be provided to the District ten (10) days prior to the tests so that an observer may be present. A written report with the results of such compliance/certification tests shall be submitted to the District within forty-five (45) days after testing.

13. The o/o shall perform the following annual compliance tests in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. Alternative test methods may be used with the prior approval of the District. The following compliance tests are required:
    a. NO_x as NO_2 in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Methods 19 and 20).
    b. VOC as CH_4 in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Methods 25A and 18).
    c. SO_x as SO_2 in ppmvd at 15% O_2 and lb/hr.
    d. CO in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Method 10).
    e. PM_{10} in mg/m^3 at 15% O_2 and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).
    f. Flue gas flow rate in scfmd.
    g. Opacity (measured per USEPA reference Method 9).
    h. Ammonia slip in ppmvd at 15% O_2.

[40 CFR 60 Subpart KKKK §60.4400]

14. The o/o shall, at least as often as once every five years (commencing with the initial compliance test), include the following supplemental source tests in the annual compliance testing:
    a. Quantification of all startup VOC emissions – pursuant to a written District approved protocol and testing schedule
    b. Quantification of shutdown VOC emissions.

15. Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B:
    a. For NO_x, Performance Specification 2.
    b. For O_2, Performance Specification 3.
    c. For CO, Performance Specification 4.
    d. For stack gas flow rate, Performance Specification 6.
    e. For ammonia, a District approved procedure that is to be submitted by the o/o.

16. The o/o shall submit to the APCO and USEPA Region IX the following information for the preceding calendar quarter by January 30, April 30, July 30 and October 30 of each year this permit is in effect. Each January 30 submittal shall include a summary of the reported information for the previous year. This information shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request:
    a. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NO_x emission rate and ammonia slip.
    b. Total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, and hours in shutdown.
    c. Date and time of the beginning and end of each startup and shutdown period.
    d. Average plant operation schedule (hours per day, days per week, weeks per year).
    e. Monthly fuel use in MMScf
    e. All continuous emissions data reduced and reported in accordance with the District-approved CEMS protocol.
    f. Maximum hourly, maximum daily, total quarterly, and total 12 month rolling average emissions of NO_x, CO, PM_{10}, VOC and SO_x (including calculation protocol).
    g. Fuel sulfur content (monthly laboratory analyses, monthly natural gas sulfur content reports from the natural gas supplier(s), or the results of a custom fuel monitoring schedule approved by USEPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart KKKK)
    h. A log of all excess emissions, including the information regarding malfunctions/breakdowns required by Rule 430.
    i. Any permanent changes made in the plant process or production which would affect air pollutant emissions, and indicate when changes were made.
    j. Any maintenance to any air pollutant control system (recorded on an as-performed basis).
    k. Written results of annual performance tests performed [60.4375]

17. The o/o must surrender to the District sufficient valid Emission Reduction Credits for this equipment before the start of construction of any part of the project for which this

equipment is intended to be used. In accordance with Regulation XIII the operator shall obtain 85.6 tons of NO_x and 23.3 tons of VOC offsets.
[Rule 1303]
[Rule 1305]

18. During an initial commissioning period not to exceed 1,250 hours and a maximum of 180 days, commencing with the first firing of fuel in this equipment, NO_x, CO, VOC and NH3 concentration limits shall not apply.

19. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the gas turbine and associated electrical delivery systems.

20. The commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial source testing, completed final plant tuning, and is available for commercial operation. Within 15 days of the conclusion of the commissioning period, the facility shall notify the District in writing of the date that the commissioning period ended and the actual number of hours that comprised the commissioning period.

21. During the commissioning period, the emission rates from the gas turbine system shall not exceed any of the following limits:
    a. NOx (as NO2) - 625 lb/hr and 15,610 lb/day;
    b. VOC (as CH4) - 464 lb/hr and 2620 lb/day;
    c. CO – 4,919 lb/hr and 28,500 lb/day;
    d. PM10 - 8 lb/hr and 211 lb/day; or
    e. SOx (as SO2) – 4.9 lb/hr and 118 lb/day

22. During the commissioning period, NOx and CO emissions rate shall be monitored using installed and calibrated CEMS.

23. The o/o shall provide stack sampling ports and platforms necessary to perform source tests required to verify compliance with District rules, regulations and permit conditions. The location of these ports and platforms shall be subject to District approval.

24. Within 60 days after achieving the maximum firing rate at which the facility will be operated, but not later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation at 100% load in compliance with the emission limits in Condition 4.

25. The initial compliance test shall include tests for the following.
    a. Formaldehyde

b. Certification of CEMS and CERMS at 100% load

26. Initial compliance testing to measure startup and shutdown VOC mass emission rates shall be conducted before the end of the commissioning period and at least once every five years thereafter. The initial compliance tests shall include tests for the following:
    a. Quantification of all startup VOC emissions – pursuant to a written District approved protocol and testing schedule
    b. Quantification of shutdown VOC emissions.

    CEMS accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with a test protocol approved by the District. If the CEM data is not able to accurately determine compliance with NOX and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO source test demonstrates that the CEM data is accurate, the startup and shutdown NOx and CO testing frequency shall return to the once every five years schedule.

22. This equipment is subject to 40 CFR 60 Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units. Carbon dioxide emissions from this turbine shall not exceed 1,000 lb CO2/MWh (gross) or 1,030 lb CO2/MWh (net). [40 CFR 60 Subpart TTTT §60.5520]

23. Emissions from all permitted equipment at the Sonoran Energy Project, shall not exceed the following emission limits, based on a rolling 12 month summary:
    a. NOx – 85.6 tons/year, verified by CEMS data, compliance testing and District approved methodology
    b. CO - 78 tons/year, verified by CEMS data, compliance testing and District approved methodology
    c. VOC as CH4 – 24.3 tons/year, verified by compliance tests and hours of operation in steady-state, pre-mix mode
    d. SOx as SO2 – 12 tons/year, verified by fuel sulfur content and fuel use data
    e. PM10 – 40.1 tons/year, verified by compliance tests and hours of operation

    These limits shall apply to all emissions from all Sonoran Energy Project permit units at this facility (as listed in Part I.A.1, of the Federal Operating Permit), and shall include emissions during all modes of operation, including startup, shutdown and malfunction.

24. Pursuant to Regulation XIII the Blythe Energy Project and Sonoran Energy Project are one stationary source. Emissions from all permit units at the Blythe Energy Project and Sonoran Energy Project facilities, shall not exceed the following emission limits, based on a rolling 12 month summary:
    a. NOx – 182.6 tons/year, verified by CEMS data, compliance testing and District approved methodology
    b. CO - 175 tons/year, verified by CEMS data, compliance testing and District approved methodology

c. VOC as CH4 – 48.3 tons/year, verified by compliance tests and hours of operation in steady-state, pre-mix mode
d. SOx as SO2 – 20.8 tons/year, verified by fuel sulfur content and fuel use data
e. PM10 - 97 tons/year, verified by compliance tests and hours of operation
These limits shall apply to all emissions from all Blythe Energy Project and Sonoran Energy Project permit units at this facility, and shall include emissions during all modes of operation, including startup, shutdown and malfunction.

25. Total fuel use in the gas turbine and associated duct burner shall not exceed 23,984 MMscf in any rolling 12-month period.

HRSG Duct Burner Authority to Construct Conditions

221.6 MMBtu/hr Natural Gas Fired Heat Recovery Steam Generator Duct Burner, Permit Number: BXXXXX

1. Operation of this equipment shall be conducted in accordance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below. [District Rule 204]

2. This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf on a twenty-four hour basis and not exceeding 0.25 grains per 100 dscf on a rolling twelve month average basis, and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.
[District Rule 1303(B); District Rule 431; District Rule 204]

3. This duct burner shall not be operated unless the combustion turbine generator with valid District permit BXXXXX, selective catalytic reduction system with valid District permit CXXXXX, and oxidation catalyst with valid District permit CXXXXX, are in operation. [District Rule 1303(A); 40 CFR part 60 subpart KKKK: emissions from the duct burner are to be included in emission limit for turbine]

4. Fuel use by this equipment shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.
[District Rule 1303(A)]

Selective Catalytic NO_x Reduction System Authority to Construct Conditions

Permit Numbers: CXXXXX

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
[District Rule 204]

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. This equipment shall be operated concurrently with the combustion turbine generator with valid MDAQMD permit BXXXXX.
[District Rule 204]

4. Ammonia shall be injected whenever the selective catalytic reduction system has reached or exceeded 550° Fahrenheit except for periods of equipment malfunction. Except during periods of startup, shutdown and malfunction, ammonia slip shall not exceed 5 ppmvd (corrected to 15% O_2), averaged over three hours verified by CEMS.
[District Rule 1302; District Rule 1303(A)]

5. The owner/operator shall record and maintain for this equipment the following on site for a minimum of five (5) years and shall provide to District personnel upon request.
a. Ammonia injection, in pounds per hour
b. Temperature, in degrees Fahrenheit
[District Rule 1302; District Rule 1303(A)]

Oxidation Catalyst Authority to Construct Conditions

Permit Numbers: CXXXXX

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below. [District Rule 204]

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles. [District Rule 204]

3. This equipment shall be operated concurrently with the combustion turbine generator under valid District permit BXXXXX.
[BACT requirement to BXXXXX]

Auxiliary Boiler Authority to Construct Conditions

66.3 MMBtu/hr Natural Gas Fired Auxiliary Boiler, Permit Number: BXXXXX

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below. [District Rule 204]

2. This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf on a twenty-four hour basis and not exceeding 0.25 grains per 100 dscf on a rolling twelve month average basis, and shall be

operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles. [District Rule 1303(B); District Rule 431; District Rule 204]

3. This equipment is subject to the Federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and Dc (Small Industrial-Commercial-Institutional Steam Generating Units). Pursuant to 40 CFR 60.48c, the owner/operator must maintain records of the quantity of fuel(s) delivered to this property during each calendar month. Records must be kept for a minimum of five years. [40 CFR part 60 subpart Dc]

4. This equipment shall not be operated for more than 7000 total hours including startup/shutdown events per rolling twelve month period. Startup/shutdown events shall not exceed 400 hours per rolling twelve month period.
[District Rule 1303(B) - Emission Offsets driven requirement]

5. Except during start up/shut down events and the initial boiler tuning period, emissions from this equipment shall not exceed the following hourly emission limits, verified by fuel use and annual compliance tests (initial compliance test with respect to VOC, SOx, and PM10):
    a. NOx as NO2 – 0.56 lb/hr (based on 7.0 ppmvd corrected to 3% O2 and averaged over one hour)
    b. CO – 2.43 lb/hr (based on 50 ppmvd corrected to 3% O2 and averaged over one hour)
    c. VOC as CH4 – 0.28 lb/hr (based on 10.0 ppmvd corrected to 3% O2 and averaged over one hour)
    d. SOx as SO2 – 0.05 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
    e. PM10 – 0.46 lb/hr (front and back half)

   [District Rule 1303(A); District Rule 1158 - Not applicable applies only in FONA]

6. During startup/shutdown events, emissions from this equipment shall not exceed the following emission rates verified by fuel use and annual compliance tests:
    a. NOx as NO2 – 1.99 lb/hr (based on 25.0 ppmvd corrected to 3% O2 and averaged over one hour)
    b. CO – 12.13 lb/hr (based on 250 ppmvd corrected to 3% O2 and averaged over one hour)
    c. VOC as CH4 – 0.69 lb/hr (based on 25.0 ppmvd corrected to 3% O2 and averaged over one hour)
    d. SOx as SO2 – 0.05 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
    e. PM10 – 0.46 lb/hr (front and back half)

7. During initial boiler tuning period, emissions from this equipment shall not exceed the following emission rates verified by fuel use and annual compliance tests:
    a. NOx as NO2 – 7.97 lb/hr (based on 100.0 ppmvd corrected to 3% O2 and averaged over one hour)
    b. CO – 12.13 lb/hr (based on 250 ppmvd corrected to 3% O2 and averaged over one hour)

c. VOC as CH4 – 0.69 lb/hr (based on 25.0 ppmvd corrected to 3% O2 and averaged over one hour)
d. SOx as SO2 – 0.09 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
e. PM10 – 0.46 lb/hr (front and back half)

8. During the initial boiler tuning period, the owner or operator shall keep records of the natural gas fuel combusted in the boiler on daily basis.

9. The o/o shall maintain an operations log for this equipment on-site and current for a minimum of five (5) years, and said log shall be provided to District personnel on request. The operations log shall include the following information at a minimum:
   a. Total operation time (hours per month, by month);
   b. Number of startups and shutdowns on a daily, monthly and rolling 12 month basis;
   c. Maximum hourly, maximum daily, monthly and rolling 12 month fuel use;
   d. Maximum hourly, maximum daily, monthly, and rolling 12 month emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); and,
   e. Any permanent changes made to the equipment that would affect air pollutant emissions, and indicate when changes were made.

   [District Rule 1302(C)(2)(a)]

8. The o/o shall perform the following annual compliance tests on this equipment in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. Alternative test methods may be used with the prior approval of the District. The following compliance tests are required:
   a. NOx as NO2 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).
   b. CO in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Method 10).

9. This boiler must be tuned up annually according to the procedures specified in 40 CFR 63.7540(a)(10).

Cooling Tower Authority to Construct Conditions

Permit Numbers: BXXXXX

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. The drift rate shall not exceed 0.0005 percent with a maximum circulation rate of 129,480 gallons per minute (gpm). The maximum hourly PM_{10} emission rate shall not exceed 1.62 pounds per hour, as calculated per a written District-approved protocol.

4. No hexavalent chromium containing compounds shall be added to cooling tower circulating water.

5. The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log which contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

6. The operator shall conduct all required cooling tower water quality tests in accordance with a District-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District review and approval.

7. A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and available to District personnel on request.

Emergency Fire Pump Authority to Construct Conditions

238 HP US EPA Tier 3, USEPA Family Name TBD. Permit Numbers: EXXXXX

1. This certified stationary compression-ignited internal combustion engine shall be installed, operated and maintained in strict accordance with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of air contaminants. Unless otherwise noted, this equipment shall also be operated in accordance with all data and specifications submitted with the application for this permit. [40 CFR 60.4211(a)]

2. This equipment shall only be fired on diesel fuel that meets the following requirements, or an alternative fuel approved by the ATCM for Stationary CI Engines:
   a. Ultra-low sulfur concentration of 0.0015% (15 ppm) or less, on a weight per weight basis; and, a cetane index or aromatic content, as follows:
   b. A minimum cetane index of 40; or,
   c. A maximum aromatic content of 35 volume percent.

Note: Use of CARB certified ULSD fuel satisfies the requirements of subparagraph 3.b above. [17 CCR 93115.5(a) and 40 CFR 60.4207(b)]

3. A non-resettable four-digit (9,999) hour timer shall be installed and maintained on this equipment to indicate elapsed engine operating time. [17 CCR 93115.10(d)]

4. This engine shall be limited to use for emergency power, defined as in response to a fire or flood. In addition, this engine shall be operated no more than 50 hours per year for testing and maintenance, unless NFPA 25 (current edition) authorizes additional time: If the 50 hour limit is exceeded, the o/o is to have the authorizing section of NFA 25 available for review at all times. [17 CCR 93115.6(a)(4)(1)(c)]; 40 CFR 60.4211(f); 40 CFR 60.4219]

5. The o/o shall maintain a operations log for this unit current and on-site, either at the engine location or at an on-site location, for a minimum of five (5) years, and be made available to the District staff within 5 working days from the District's request, and this log shall be provided to District, State and Federal personnel upon request. The log shall include, at a minimum, the information specified below:
   a. Date of each use and duration of each use (in hours) [40 CFR 60.4214];
   b. Reason for use (testing & maintenance, emergency, required emission testing) [40 CFR 60.4214];
   c. Calendar year operation in terms of fuel consumption (in gallons) and total hours [District and State Only]; and,
   d. Fuel sulfur concentration (the o/o may use the supplier's certification of sulfur content if it is maintained as part of this log) [40 CFR 60.4207].

6. This equipment shall exhaust through a stack at a minimum height of 10 feet. [District Rule 1302; Demonstration of compliance with AAQS]

7. This engine is subject to the requirements of Title 17 CCR 93115, the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines and 40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (NSPS). In the event of a conflict between these conditions and the ATCM or NSPS, the more stringent requirements shall govern. [District Rule 1302]

8. The facility must submit accurate emissions inventory data to the District, in a format approved by the District, upon District request. [District Rule 204]

Appendix A
Public Notice

NOTICE of TITLE V PERMIT SIGNIFICANT MODIFICATION - BLYTHE ENERGY PROJECT & PRELIMINARY DETERMINATION OF COMPLIANCE – SONORAN ENERGY PROJECT

NOTICE IS HEREBY GIVEN THAT the Mojave Desert Air Quality Management District (MDAQMD) has completed the preliminary decision pertaining to an Application for New Source Review for the Sonoran Energy Project (SEP), an electrical generating facility. The SEP has been proposed for a 76 acre site five miles east of the City of Blythe, California and located adjacent to the existing Blythe Energy Project (BEP). The MDAQMD has prepared a Preliminary Determination of Compliance (PDOC) for SEP pursuant to MDAQMD Rule 1306. The PDOC finds that, subject to specified permit conditions, the proposed project will comply with all applicable MDAQMD rules and regulations.

BEP and SEP are owned by Blythe Energy, Inc. and Altagas Sonoran Energy, Inc. which are subsidiaries of the same parent company, Altagas Power Holdings. Because BEP and SEP are under common control and located on contiguous property they are considered one stationary source. Although under common control, BEP and SEP are owned by different subsidiaries and therefore maintain separate District permits. BEP operates under federal operating permit 130202262. SEP has applied for a federal operating permit which will be processed separately from these current permitting actions.

Blythe Energy, Inc., operating their facility at 385 N. Buck Blvd. in Blythe California has applied for a Significant Modification to their Federal Operating Permit (FOP) pursuant to the provisions of MDAQMD Regulation XII. The applicant is a facility engaged in electric power generation and is of a size requiring a Title V Permit. The applicant is required to submit this change to their FOP because the facility will be reducing the lb/hr PM10 limit for the combustion turbines and also reducing the ton/year facility PM10 and SOx emission limits. Because BEP and SEP are one stationary source and because the emission reductions are occurring simultaneously with the permitting of SEP, the reductions will be used to meet the offset burden of the SEP. The proposed changes constitute a major modification of the BEP FOP pursuant to Rule 1201(T)(3) in that they change a case-by-case determination of an emissions limitation imposed pursuant to District Regulation XIII – New Source Review.

AVAILABILITY OF DOCUMENTS: Copies of the BEP/SEP Applications, the Statement of Basis, New Source Review Preliminary Determination / FOP Modification Preliminary Determination, the Proposed Draft BEP FOP, and other supporting documentation are available from the MDAQMD by mail, in person, via the following link on the MDAQMD website:

http://www.mdaqmd.ca.gov/index.aspx?page=416

or by contacting Roseana Brasington, Mojave Desert Air Quality Management District, 14306 Park Avenue, Victorville, CA 92392, Phone: (760) 245-1661, extension 5706, Facsimile: (760) 245-2022 or at rnbrasington@mdaqmd.ca.gov . Traducción esta disponible por solicitud.

REQUEST FOR COMMENTS: Interested persons are invited to submit written comments and/or other documents regarding the terms and conditions of the proposed changes. If you submit written comments, you may also request a public hearing on the proposed modification of the FOP. To be considered, comments, documents and requests for public hearing must be submitted no later than

5:00 P.M. on Monday, January 18, 2016 to the MDAQMD, Attention: Roseana Navarro-Brasington, at the address listed above.

RIGHT TO PETITION USEPA FOR RECONSIDERATION: Title V Permits are also subject to review and approval by USEPA. If USEPA has not objected to a proposed permit modification and District has not addressed a public comment in a satisfactory manner, the public may also petition USEPA, Region 9, Operating Permits Section at 75 Hawthorne Street, San Francisco, CA 94105, within 60 days after the end of the 45-day USEPA review period, to reconsider the decision to not object to the permit modification. The USEPA review period expires on February 1, 2016.