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

March 16, 2011

Mr. Alan Solomon
Project Manager
Siting, Transmission and Environmental Protection Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Subject: Watson Cogeneration Steam and Electric Reliability Project (09-AFC-01);
BP West Coast Products LLC; Facility ID: 131003; 2350 E. 223rd Street, Carson, CA 90810
Watson Cogeneration Facility; 22850 S. Wilmington Avenue, Carson, CA 90745

Dear Mr. Solomon:

The purpose of this letter is to transmit to the California Energy Commission (CEC) the South Coast Air Quality Management District's (AQMD's) Final Determination of Compliance (FDOC) for the Watson Cogeneration Steam and Electric Reliability Project (09-AFC-01). As a result of the comments received during the public and EPA review and comment period, the FDOC incorporates amendments to the Preliminary Determination of Compliance (PDOC), which was issued to the CEC on October 12, 2010. The Watson Cogeneration Steam and Electric Reliability Project involves permitting of a fifth cogeneration train at the Watson Cogeneration Facility as well as changes to permits issued to the four existing cogeneration units. A Title V permit was issued to the BP Carson Refinery (BP), which includes the Watson Cogeneration Facility, on September 1, 2009. In the FDOC, additions to the Title V permit are highlighted. Provisions which are underlined as well as highlighted, are amendments to the PDOC. Deletions to the permit are struck through. Items which have double strike through are deletions from the PDOC. The attached table also lists changes made to the PDOC.

The AQMD has completed distribution of a public notice for this project, as required under AQMD Rules 212 and 3006, to area residents and to members of the public who are on an AQMD list as being interested in significant changes to the BP Title V permit. The public notice was also published in newspapers serving the vicinity of the facility. The 30 day comment period has concluded. Comments regarding the project were received only from the facility (BP) and are incorporated, as appropriate, into the FDOC.

If you have any questions or wish to provide comments regarding this project, please contact Mr. Jay Chen, Senior Engineering Manager, at (909) 396-2664 or by email at jchen@aqmd.gov. For any questions regarding the FDOC, please contact Mr. Rafik Beshai at (909) 396-3611 or by email at rbeshai@aqmd.gov.

Very truly yours,

Mohsen Nazemi, P.E.
Deputy Executive Officer
Engineering and Compliance

Attachment
cc: Eric Daley, BP West Coast Products LL
Terry O'Brien, CEC

Item #	Change to PDOC	Reason for Change
1	For Gas Turbines (Devices: D1226, D1233, D1236 and D1239) changed designation of 150 ppmv SO_2 limit in "Emissions and Requirements" column, from (5B) - command and control emission limit, to (8) 40 CFR limit.	This SO_2 concentration limit is a 40 CFR 60 Subpart GG standard and thus is tagged as being due to a 40 CFR limit.
2	For Duct Burners (Devices: D1227, D1234, D1237, D1240) added NOx limit of 0.2 lbs/MMBtu associated with NSPS (40 CFR 60 Subpart Db).	This NOx limit was inadvertently left out of the PDOC. The limit remains applicable to the existing cogeneration systems.
3	Removed description of the new Heat Recovery Boiler from device DX2 and listed it as a separate device (DX4). Also, for the new Heat Recovery Boiler (DX4), eliminated listing of fuels (natural gas and refinery gas) and heat input rating (510 MMBtu/hr). These items will continue to be listed in the description of the Duct Burner (DX2).	The new Heat Recovery Boiler is an unfired unit and hence fuels fired (natural gas and refinery gas) and heat input rating (510 MMBtu/hr) are not relevant to this equipment. These parameters are associated with operation of the Duct Burner and thus, the fuels (natural gas and refinery gas) and heat input rating (510 MMBtu/hr) will continue to be listed under the description of the Duct Burner.
4	For the new Gas Turbine (DX1) and Duct Burner (DX2), eliminated proposed A248 conditions and replaced them with new A195 conditions.	Due to limitations of the SCAQMD facility permit program, proposed A248 conditions are not used for specifying averaging time and are thus replaced with new A195 conditions. The requirements of the conditions remain unchanged.
5	Listed devices which are common to all cogeneration units (D1228, D1229, D1231, D1232, D2111, D2112, D2113, D2740, D2775, and D2741) under Process 17, System 9 - the new system created for listing of Cogeneration Unit No. 5 equipment.	For consistency with equipment listing for Cogeneration Unit Nos. 1 through 4, listed equipment common to all cogeneration units also under Process 17, System 9 - the new system for listing of Cogeneration Unit No. 5 equipment. Note, devices D2111, D2112, and D2113 - which are associated with butane fuel - will not be used in Cogeneration Unit No. 5 since this system will not fire butane.
6	For the new SCR (CX1) and CO Oxidation Catalyst (CX2), eliminated listing of volume of "1600 CU. FT."	The design of the control equipment (SCR and CO Oxidation Catalyst) has not been completed and the final volume may be different from what was stated in the permit application for the APC system. Condition S7.X2 requires BP to submit drawings and specifications of the SCR and CO Oxidation Catalyst to the SCAQMD, at least 30 days prior to construction, and that this equipment must meet the performance specifications stated in the PC application. Therefore, this condition is sufficient to ensure that the final design will meet the agreed upon performance specifications and the listing of catalyst volume is not necessary.
7	Amended the equipment listed in the "Connected To" column for the new cogeneration unit and associated control devices.	Amended the listing of equipment in the "Connected To" column for the Gas Turbine (DX1), Duct Burner (DX2), SCR (CX1), CO Oxidation Catalyst (CX2) and Stack (SX1). This information now shows that the Gas Turbine (DX1) and Duct Burner (DX2) are both vented to the SCR (CX1). The SCR (CX1) is connected to the CO Oxidation Catalyst (CX2), as well as the Gas Turbine (DX1) and the Duct Burner (DX2).

		The CO Oxidation Catalyst (CX2) is connected to the Stack (SX1), as well as the SCR (CX1). The Stack (SX1) is connected to the CO Oxidation Catalyst (CX2). These amendments are made to clarify how these devices are interconnected.
8	In the Background and Emissions Calculation sections changed references to limiting particulate matter emissions, in the form of PM10 (not PM), from all cogeneration units.	Since new condition A63.X2 limits PM10 emissions from all five cogeneration units, the discussion in the Background and Emission Calculation sections is amended to state that the SCAQMD will limit emissions of PM10 (not PM, as stated in the PDOC). This change is made so that the discussion and permit condition both refer to limiting PM10 emissions.
9	In the Emission Calculation section - Table 4 - amended the number of annual warm startups, from 12 to 24, and the number of shutdowns from 16 to 29. In the Emission Calculation section - Table 5 - amended annual CO emissions, based on the change in annual warm startups and shutdowns.	Based on expected operation of Cogeneration Unit No. 5, the number of allowed annual warm startups is increased, from 12 to 24, and number of permitted annual shutdowns is increased from 16 to 29. Table 4 is amended to reflect this update in number of allowed warm startups and shutdowns. The change in permitted warm startups and shutdowns results in a change in annual CO emissions. Thus, annual CO emissions from Cogeneration Unit No. 5, stated in Table 5, are amended. The notes in this table are also amended to reflect the change in permitted warm startups and shutdowns.
10	In the Emission Calculation section - Tables 3 and 5 - hourly and daily SO_x emissions are amended and are based on natural gas total sulfur content of 0.75 gr /100 scf (as H_2S). Hourly SO_x emissions are calculated using 0.75 gr H_2S/100 scf in natural gas and 40 ppm H_2S in refinery gas, while daily emissions are calculated using 0.75 gr H_2S/100 scf in natural gas and 30 ppm H_2S in refinery gas. Other sections of the FDOC (regulatory evaluation) are also amended to evaluate SO_x emissions based on natural gas total sulfur content of 0.75 gr H_2S /100 scf. Annual SO_x emissions continue to be based on natural gas sulfur content of 0.29 gr/100 scf.	According to Southern California Gas Company Rule 30, the total sulfur content of natural gas, as H2S, may be as high as 0.75 gr/100 scf. Thus, short term emissions (hourly or daily) are calculated using this sulfur concentration. The annual average sulfur content of natural gas is expected to be 0.29 gr H2S/100 scf and thus annual emissions continue to be based on this sulfur concentration.
11	Condition S31.10 has been eliminated and replaced with condition S31.X.	New condition S31.X requires that process drains be in compliance with 40 CFR 60 Subpart QQQ, which previously was not addressed in the proposed permit. Therefore, permit condition S31.10 is replaced with condition S31.X, to show applicability of provisions of 40 CFR 60 Subpart QQQ to the new cogeneration unit.
12	Conditions A99.X1, A99.X2, A99.X3, and A99.X4 have been amended to allow for 24 warm startups and 29 shutdowns per year (originally limited to 12 warm startups and 16 shutdowns). The limit for the number of cold startups remains at 4 per year.	Based on expected operation of Cogeneration Unit No. 5, the number of permitted annual warm startups and shutdowns are increased.
13	Condition A195.X1 is amended by addition of parenthesis to clarify a calculation method.	The ammonia calculation formula is amended from, NH3(ppmv) = [a-b*c/1E6]*1E6/b, to NH3(ppmv) = [a-(b*c)/1E6]*1E6/b . BP/Watson

		requested the addition of parenthesis in this formula, to clarify the calculation.
14	Condition A433.X1 is amended by defining "cold startup," "warm startup," and "shutdown."	For clarification, condition A433.X1 is amended by definition of “cold startup,” “warm startup,” and “shutdown.”
15	Condition D28.1 is amended to require annual source testing of PM10 emissions. Previously, this condition required annual testing for total PM emissions.	Since results of source testing required under condition D28.1 are used to determine compliance with the PM10 emissions limit of condition A63.X2, the condition is amended to require testing for PM10. The change is made so that the same pollutant (PM10) is referenced in the conditions requiring source testing and the condition limiting emissions.
16	Condition D29.X2 is amended to allow 60 days for the submittal of the source test report to the SCAQMD.	The time for submittal of the source test report in condition D29.X2 is amended to 60 days. This period for report submission is consistent with the requirement under Section E - Administrative Conditions, Condition 10, and thus the permit is amended accordingly.
17	Eliminated reference to condition E193.X for Device DX1.	Reference to condition E193.X has been eliminated, as no such condition was proposed in the PDOC. During the drafting of the PDOC, condition E193.X was replaced with condition S7.X1, which addresses compliance with CEC requirements. Thus, the reference to condition E193.X, under Device DX1, is erroneous and is eliminated.
18	In the section evaluating compliance with Modeling requirements under Reg XIII/Rule 2005, added a statement regarding the new federal 1-hr average NO_2 standard of 100 ppb.	Addressed compliance of the project with new federal 1-hr average NO_2 ambient air quality standard by stating that the south coast air basin is not designated as non-attainment with this standard and thus demonstration of compliance with the new standard is not required.
19	In the section evaluating Rule 212 compliance, added a statement regarding completion of distribution of the public notice to addresses within 1/4 mile of the facility and publication of the public notice in local newspapers.	A statement is added to indicate that distribution of the public notice to local addresses and publication of the notice in local newspapers has been completed, as required under Rule 212.
20	In the section evaluation Reg XVII compliance, amended annual CO emissions. Further, in the notes of the Reg XVII table included a statement regarding VOC and PM10 as being currently designated as non-attainment air contaminants in the South Coast Air Basin.	Based on the change in permitted warm startups and shutdowns, annual CO emissions have been adjusted and the new emissions rate is stated in the table assessing the Reg XVII Significant Increase. Further, the Reg XVII table is amended to state that VOC and PM10 are currently designated as non-attainment air contaminants and that the South Coast Air Basin is currently in attainment with ambient air standards for CO, NO2, SO2, and lead.
21	In the section evaluating Reg XXX compliance, added a statements regarding completion of distribution of the public notice to other governmental agencies and members of the public. Also added a statement regarding publication of the public notice in local newspapers.	A statement is added to indicate that distribution of the public notice to other governmental agencies and to members of the public has been completed. Also confirms that EPA review of the proposed permit has been completed.
22	In Attachment #2, amended the annual NO_x	Based on the change in permitted warm startups

	emissions calculation based on the change in the number of permitted warm startups and shutdowns. Performed a similar calculation for annual CO emissions.	and shutdowns, the annual NO_x emission calculation is amended. Performed a similar calculation for annual CO emissions from the new cogeneration unit.
23	In the notes of the table in Attachment #3, the ratio of fuels combusted in the combustion turbine is amended to 65 vol% natural gas/ 35 vol% refinery gas (instead of 65 wt% natural gas/35 wt% refinery gas stated in the PDOC).	Based on updated information submitted by the applicant, the maximum refinery gas input to the combustion turbine will be 35 vol%, and not 35wt% as stated in the Application for Certification.
24	Condition C157.X is revised to state: The operator shall install and maintain a pressure relief valve with a minimum pressure set at 30 psig.	Revised condition C157.X correctly requires that the pressure relief valve serving the new aqueous ammonia storage be maintained "at a minimum pressure of 30 psig" and not at exactly 30 psig, as originally proposed.
25	The child condition under condition B61.X1, is amended as follows: " Refinery gas is defined as a mixture of refinery fuel gas, produced within the refinery, and natural gas obtained from a utility regulated by the Public Utilities Commission (PUC), for which the natural gas component of the mixture (formed at a point upstream of the sampling location for Total Reduced Sulfur concentration) shall not exceed 50% of the total, by Higher Heating Value (HHV) content.."	This amendment is to clarify that mixing of natural gas with refinery fuel gas is allowed to meet permit limits of Total Reduced Sulfur in the Refinery Gas and that this mixing must take place upstream of the Total Reduced Sulfur sampling location. However, the mixture may not contain more than 50% natural gas, based on Higher Heating Value (HHV).
26	A child condition under condition D12.X1, is amended as follows: "The purpose of this condition is to demonstrate compliance with the limitation of refinery fuel gas, as having natural gas accounting for no more than 50% of the Higher Heating Value (HHV) of the mixture, formed at a point upstream of the sampling location for Total Reduced Sulfur concentration."	This amendment is to clarify that mixing of natural gas with refinery fuel gas is allowed to meet permit limits of Total Reduced Sulfur in the Refinery Gas and that this mixing must take place upstream of the Total Reduced Sulfur sampling location. However, the mixture may not contain more than 50% natural gas, based on Higher Heating Value (HHV).

FINAL DETERMINATION OF COMPLIANCE

COMPANY NAME BP WEST COAST PRODUCTS LLC

COMPANY ADDRESS P.O. BOX 6210
CARSON, CA 90749

EQUIPMENT LOCATION 2350 E. 223RD STREET
CARSON, CA 90810

FACILITY ID 131003

EQUIPMENT DESCRIPTION

(Note: Additions to the permit are highlighted. Additions which are underlined are amendments to the PDOC. Deletions to the permit are struck through. Items which have double strike through are deletions which are amendments to the PDOC.)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
Process 17: ELECTRIC GENERATION					
System 1: COGENERATION UNIT NO. 1					
GAS TURBINE, W/TWO GAS STOP/RATIO VALVES, WITH STEAM INJECTION, BUTANE, NATURAL GAS, REFINERY GAS, GENERAL ELECTRIC, MODEL PG7111EA, DRIVING A 90.87 MVA ELECTRIC GENERATOR, SITE RATED AT 82.72 MW, 985.5 MMBTU/HR A/N ~~411168~~ 508456	D1226	C1242 C1243 S1247	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	[CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO: 2.5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996]; NOX: 96 PPMV (8) [40CFR60 Subpart GG, 2-24-2006]; NOX: 8 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]; PM: 11 LBS/HR (5) [RULE 475, 10-8-1976, RULE 475, 8-7-1978]; PM: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976, RULE 475, 8-7-1978]; PM: 0.1 GRAINS/SCF (5B) [RULE 409, 8-7-1981] SO2: 150 PPMV (~~5B~~ 8) [40CFR60 Subpart GG, 2-24-2006]; SOX: 2 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]	A63.12, A63.X2, A99.1, A99.2, A99.3, A248.1, A248.2, A248.3, A248.4, A327.1, B61.1, B61.2, B61.3, B61.4, C1.33, C1.34, D12.1, D12.2, D28.1, D90.3, D90.4, D90.17, D94.1, E17.1, E54.1, E73.1, E226.1, H23.1, H23.18, K67.3

BURNER, DUCT, NATURAL GAS, REFINERY GAS, INCLUDING VENT FOR MEROX SYSTEMS NO. 1 & 2, COMMON VENTING SYSTEM, 340 MMBTU/HR A/N ~~411168~~ 508456	D1227	C1242 C1243	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	[CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; NOX: 0.2 LBS/MMBTU (8) [40CFR60 Subpart Db, 1-28-2009]; NOX: 8 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]; PM: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM: 0.01 GRAINS/SCF (5A) [RULE 476, 10-8-1976]; PM: 11 LBS/HR (5B) [RULE 476, 10-8-1976]	A63.X2, A327.2, B61.1, B61.2, B61.3, B61.4, D28.1, D90.3, D90.4, E54.1, E71.1, H23.1, H23.19
STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR, RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1228				
STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1229				
BOILER, WASTE HEAT RECOVERY, STEAM, DUAL PRESSURE, UNFIRED, 583,000 #/HR STM AT 625 PSIG, 21,400 #/HR STM@150 PSIG A/N ~~411168~~ 508456	D1230				
CONDENSER, STEAM SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1231				
CONDENSER, STEAM, SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1232				
HEAT EXCHANGER, BUTANE VAPORIZER, RPV 4830, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2111				

DRUM, KNOCK OUT, BUTANE, RPV 4831, COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4)~~; HEIGHT: 11 FT; DIAMETER: 5 FT 6 IN A/N ~~411169~~ 508471	D2112				
HEAT EXCHANGER, BUTANE SUPERHEATER, RPV 4832, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2113				
BLOWER, RW 0027-08704, BUTANE, CENTRIFUGAL TYPE, VERTICAL POSITION SEALED WITH NITROGEN, 20 HP A/N ~~411169~~ 508471	D2114				
COMPRESSOR, NO. 1, RW-0045-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3 & 4~~) A/N ~~411169~~ 508471	D2740				
COMPRESSOR, NO. 2, RW-0046-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2775				
DRUM, RPV-4800, SLOP COLLECTING (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~), HEIGHT: 9 FT; DIAMETER: 4 FT A/N ~~411169~~ 508471	D2741				
DRUM, RPV-4829, FUEL MIX, HIGH PRESSURE, HEIGHT: 11 FT; DIAMETER: 6 FT 6 IN A/N ~~411169~~ 508471	D2742				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N ~~411168~~ 508456	D2585				H23.3
System 2: COGENERATION UNIT NO. 2					

GAS TURBINE, W/TWO GAS STOP/RATIO VALVES, WITH STEAM INJECTION, BUTANE, NATURAL GAS, REFINERY GAS, GENERAL ELECTRIC, MODEL PG7111EA, DRIVING A 90.87 MVA ELECTRIC GENERATOR, SITE RATED AT 82.72 MW, 985.5 MMBTU/HR A/N ~~411169~~ 508471	D1233	C1248 C1249 S1251	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	[CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO: 2.5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996]; NOX: 96 PPMV (8) [40CFR60 Subpart GG, 2-24-2006]; NOX: 8 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]; PM: 11 LBS/HR (5) [RULE 475, 10-8-1976, RULE 475, 8-7-1978]; PM: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976, RULE 475, 8-7-1978]; PM: 0.1 GRAINS/SCF (5B) [RULE 409, 8-7-1981] SO2: 150 PPMV (~~5B~~ 8) [40CFR60 Subpart GG, 2-24-2006]; SOX: 2 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]	A63.12, A63.X2, A99.1, A99.2, A99.3, A248.1, A248.2, A248.3, A248.4, A327.1, B61.1, B61.2, B61.3, B61.4, C1.33, C1.34, D12.1, D12.2, D28.1, D90.3, D90.4, D90.17, D94.1, E17.1, E54.1, E73.1, E226.1, H23.1, H23.18, K67.3
BURNER, DUCT, NATURAL GAS, REFINERY GAS, INCLUDING VENT FOR MEROX SYSTEMS NO. 1 & 2, COMMON VENTING SYSTEM, 340 MMBTU/HR A/N ~~411169~~ 508471	D1234	C1248 C1249 C1252 C1253	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	[CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; NOX: 0.2 LBS/MMBTU (8) [40CFR60 Subpart Db, 1-28-2009]; NOX: 8 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]; PM: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM: 0.01 GRAINS/SCF (5A) [RULE 476, 10-8-1976]; PM: 11 LBS/HR (5B) [RULE 476, 10-8-1976]	A63.X2, A327.2, B61.1. B61.2, B61.3, B61.4, D28.1, D90.3, D90.4, E54.1, E71.1, H23.1, H23.19
STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR, RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1228				

STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1229				
BOILER, WASTE HEAT RECOVERY, STEAM, DUAL PRESSURE, UNFIRED, 583,000 #/HR STM AT 625 PSIG, 21,400 #/HR STM@150 PSIG A/N ~~411169~~ 508471	D1235				
CONDENSER, STEAM SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1231				
CONDENSER, STEAM, SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1232				
HEAT EXCHANGER, BUTANE VAPORIZER, RPV 4830, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2111				
DRUM, KNOCK OUT, BUTANE, RPV 4831, COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4)~~; HEIGHT: 11 FT; DIAMETER: 5 FT 6 IN A/N ~~411169~~ 508471	D2112				
HEAT EXCHANGER, BUTANE SUPERHEATER, RPV 4832, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2113				
BLOWER, RW 0027-08704, BUTANE, CENTRIFUGAL TYPE, VERTICAL POSITION SEALED WITH NITROGEN, 20 HP A/N ~~411169~~ 508471	D2114				

COMPRESSOR, NO. 1, RW-0045-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3 & 4~~) A/N ~~411169~~ 508471	D2740				
COMPRESSOR, NO. 2, RW-0046-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2775				
DRUM, RPV-4800, SLOP COLLECTING (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~), HEIGHT: 9 FT; DIAMETER: 4 FT A/N ~~411169~~ 508471	D2741				
DRUM, RPV-4829, FUEL MIX, HIGH PRESSURE, HEIGHT: 11 FT; DIAMETER: 6 FT 6 IN A/N ~~411169~~ 508471	D2742				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N ~~411169~~ 508471	D2586				H23.3
System 3: COGENERATION UNIT NO. 3					

GAS TURBINE, W/TWO GAS STOP/RATIO VALVES, WITH STEAM INJECTION, BUTANE, NATURAL GAS, REFINERY GAS, GENERAL ELECTRIC, MODEL PG7111EA, DRIVING A 90.87 MVA ELECTRIC GENERATOR, SITE RATED AT 82.72 MW, 985.5 MMBTU/HR A/N ~~411170~~ 508472	D1236	C1252 C1253 S1255	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	[CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO: 2.5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996]; NOX: 96 PPMV (8) [40CFR60 Subpart GG, 2-24-2006]; NOX: 8 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]; PM: 11 LBS/HR (5) [RULE 475, 10-8-1976, RULE 475, 8-7-1978]; PM: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976, RULE 475, 8-7-1978]; PM: 0.1 GRAINS/SCF (5B) [RULE 409, 8-7-1981] SO2: 150 PPMV (~~5B~~ 8) [40CFR60 Subpart GG, 2-24-2006]; SOX: 2 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]	A63.12, A63.X2, A99.1, A99.2, A99.3, A248.1, A248.2, A248.3, A248.4, A327.1, B61.1, B61.2, B61.3, B61.4, C1.33, C1.34, D12.1, D12.2, D28.1, D90.3, D90.4, D90.17, D94.1, E17.1, E54.1, E73.1, E226.1, H23.18, H23.1, K67.3
BURNER, DUCT, NATURAL GAS, REFINERY GAS, INCLUDING VENT FOR MEROX SYSTEMS NO. 1 & 2, COMMON VENTING SYSTEM, 340 MMBTU/HR A/N ~~411170~~ 508472	D1237	C1252 C1253	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	[CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; NOX: 0.2 LBS/MMBTU (8) [40CFR60 Subpart Db, 1-28-2009]; NOX: 8 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]; PM: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM: 0.01 GRAINS/SCF (5A) [RULE 476, 10-8-1976]; PM: 11 LBS/HR (5B) [RULE 476, 10-8-1976]	A63.X2, A327.2, B61.1. B61.2, B61.3, B61.4, D28.1, D90.3, D90.4, E54.1, E71.1, H23.1, H23.19
STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR, RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1228				

STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1229				
BOILER, WASTE HEAT RECOVERY, STEAM, DUAL PRESSURE, UNFIRED, 583,000 #/HR STM AT 625 PSIG, 21,400 #/HR STM@150 PSIG A/N ~~411170~~ 508472	D1238				
CONDENSER, STEAM SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1231				
CONDENSER, STEAM, SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1232				
HEAT EXCHANGER, BUTANE VAPORIZER, RPV 4830, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2111				
DRUM, KNOCK OUT, BUTANE, RPV 4831, COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4)~~; HEIGHT: 11 FT; DIAMETER: 5 FT 6 IN A/N ~~411169~~ 508471	D2112				
HEAT EXCHANGER, BUTANE SUPERHEATER, RPV 4832, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2113				
BLOWER, RW 0027-08704, BUTANE, CENTRIFUGAL TYPE, VERTICAL POSITION SEALED WITH NITROGEN, 20 HP A/N ~~411169~~ 508471	D2114				

COMPRESSOR, NO. 1, RW-0045-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3 & 4~~) A/N ~~411169~~ 508471	D2740				
COMPRESSOR, NO. 2, RW-0046-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2775				
DRUM, RPV-4800, SLOP COLLECTING (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~), HEIGHT: 9 FT; DIAMETER: 4 FT A/N ~~411169~~ 508471	D2741				
DRUM, RPV-4829, FUEL MIX, HIGH PRESSURE, HEIGHT: 11 FT; DIAMETER: 6 FT 6 IN A/N ~~411169~~ 508471	D2742				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N ~~411170~~ 508472	D2587				H23.3
System 4: COGENERATION UNIT NO. 4					

GAS TURBINE, W/TWO GAS STOP/RATIO VALVES, WITH STEAM INJECTION, BUTANE, NATURAL GAS, REFINERY GAS, GENERAL ELECTRIC, MODEL PG7111EA, DRIVING A 90.87 MVA ELECTRIC GENERATOR, SITE RATED AT 82.72 MW, 985.5 MMBTU/HR A/N ~~411171~~ 508473	D1239	C1256 C1257 S1259	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	[CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; CO: 2.5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996]; NOX: 96 PPMV (8) [40CFR60 Subpart GG, 2-24-2006]; NOX: 8 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]; PM: 11 LBS/HR (5) [RULE 475, 10-8-1976, RULE 475, 8-7-1978]; PM: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976, RULE 475, 8-7-1978]; PM: 0.1 GRAINS/SCF (5B) [RULE 409, 8-7-1981] SO2: 150 PPMV (~~5B~~ 8) [40CFR60 Subpart GG, 2-24-2006]; SOX: 2 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]	A63.12, A63.X2, A99.1, A99.2, A99.3, A248.1, A248.2, A248.3, A248.4, A327.1, B61.1, B61.2, B61.3, B61.4, C1.33, C1.34, D12.1, D12.2, D28.1, D90.3, D90.4, D90.17, D94.1, E17.1, E54.1, E73.1, E226.1, H23.1, H23.18, K67.3
BURNER, DUCT, NATURAL GAS, REFINERY GAS, INCLUDING VENT FOR MEROX SYSTEMS NO. 1 & 2, COMMON VENTING SYSTEM, 340 MMBTU/HR A/N ~~411171~~ 508473	D1240	C1256 C1257	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	[CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; NOX: 0.2 LBS/MMBTU (8) [40CFR60 Subpart Db, 1-28-2009]; NOX: 8 PPMV (4) [RULE 2005, 4-20-2001; RULE 2005, 5-6-2005]; PM: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM: 0.01 GRAINS/SCF (5A) [RULE 476, 10-8-1976]; PM: 11 LBS/HR (5B) [RULE 476, 10-8-1976]	A63.X2, A327.2, B61.1. B61.2, B61.3, B61.4, D28.1, D90.3, D90.4, E54.1, E71.1, H23.1, H23.19
STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR, RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1228				

STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1229				
BOILER, WASTE HEAT RECOVERY, STEAM, DUAL PRESSURE, UNFIRED, 583,000 #/HR STM AT 625 PSIG, 21,400 #/HR STM@150 PSIG A/N ~~411171~~ 508473	D1241				
CONDENSER, STEAM SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1231				
CONDENSER, STEAM, SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1232				
HEAT EXCHANGER, BUTANE VAPORIZER, RPV 4830, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2111				
DRUM, KNOCK OUT, BUTANE, RPV 4831, COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4)~~; HEIGHT: 11 FT; DIAMETER: 5 FT 6 IN A/N ~~411169~~ 508471	D2112				
HEAT EXCHANGER, BUTANE SUPERHEATER, RPV 4832, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2113				
BLOWER, RW 0027-08704, BUTANE, CENTRIFUGAL TYPE, VERTICAL POSITION SEALED WITH NITROGEN, 20 HP A/N ~~411169~~ 508471	D2114				

COMPRESSOR, NO. 1, RW-0045-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3 & 4~~) A/N ~~411169~~ 508471	D2740				
COMPRESSOR, NO. 2, RW-0046-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2775				
DRUM, RPV-4800, SLOP COLLECTING (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~), HEIGHT: 9 FT; DIAMETER: 4 FT A/N ~~411169~~ 508471	D2741				
DRUM, RPV-4829, FUEL MIX, HIGH PRESSURE, HEIGHT: 11 FT; DIAMETER: 6 FT 6 IN A/N ~~411169~~ 508471	D2742				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N ~~411171~~ 508473	D2588				H23.3
System 9: COGENERATION UNIT 5					S2.X1, S7.X1, ~~S31.10~~, S31.X

GAS TURBINE, NATURAL GAS, REFINERY GAS, GENERAL ELECTRIC, MODEL 7EA, WITH DRY LOW NOX COMBUSTORS, 1069.9 MMBTU/HR A/N: 496922 GENERATOR, ELECTRIC, NOMINAL RATING AT 85 MW (NET)	DX1	CX1 ~~CX2~~ ~~SX1~~	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	**CO**: 2 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1)-BACT, 12-6-2002;* **RULE 1703 PSD Analysis, 10-7-1988**]; **CO**: 3 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1)-BACT, 12-6-2002;* **RULE 1703 PSD Analysis, 10-7-1988**]; **CO**: 2000 PPMV (5) [RULE 407, 4-2-1982] **NOX**: (INTERIM) 44 LBS/MMCF (1) [RULE 2012, 5-6-2005]; **NOX**: 15 PPMV (8) [40 CFR 60 Subpart KKKK, 6-6-2006]; **NOX**: 2 PPMV (4) [RULE 2005, 5-6-2005; **RULE 1703 PSD Analysis, 10-7-1988**] **PM**: 11 LBS/HR (5) [**RULE 475, 10-8-1976**; *RULE 475, 8-7-1978*]; **PM**: 0.01 GRAINS/SCF (5A) [**RULE 475, 10-8-1976**; *RULE 475, 8-7-1978*]; **PM**: 0.1 GRAINS/SCF (5B) [RULE 409, 8-7-1981] **SOX**: (INTERIM) ~~0.80~~ 2.02 LBS/MMCF (1) NATURAL GAS [RULE 2011, 5-6-2005]; **SOX**: (INTERIM) 5.07 LBS/MMCF (1) REFINERY GAS [RULE 2011, 5-6-2005]; **SOX**: 0.06 LBS/MMBTU (8) [40 CFR 60 Subpart KKKK, 6-6-2006]; **SO2**: (9) [40CFR72 – ACID RAIN] **VOC**: 2 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1)-BACT, 12-6-2002]*	A63.X1, A63.X2, A99.X2, A99.X3, A99.X4, A99.X5, A99.X6, A99.X7, A195.X2, A195.X3, A195.X4, A195.X5, ~~A248.X1, A248.X2, A248.X3, A248.X4,~~ A327.1, A433.X1, B61.X1, B61.X2, C1.X1, D12.1, D12.X1, D29.X1, D29.X3, D29.X4, D82.X1, D82.X2, D90.X1, D90.X2, D94.1, ~~E193.X~~, H23.X1, H23.X2, I296.X1, K40.X, K67.3, K67.X1

BURNER, DUCT, NATURAL GAS, REFINERY GAS, LOW NOX BURNER, 510 MMBTU/HR ~~BOILER, TURBINE EXHAUST HEAT RECOVERY, REFINERY GAS, NATURAL GAS, UNFIRED, 624,000 LBS/HR STEAM, 510 MMBTU/HR, WITH~~ A/N: 496922	DX2	CX1 ~~CX2~~ ~~SX1~~	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	**CO**: 2 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1)-BACT, 12-6-2002;* **RULE 1703 PSD Analysis, 10-7-1988**]; **CO**: 3 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1)-BACT, 12-6-2002;* **RULE 1703 PSD Analysis, 10-7-1988**]; **CO**: 2000 PPMV (5) [RULE 407, 4-2-1982] **NOX**: 2 PPMV (4) [RULE 2005, 5-6-2005; **RULE 1703 PSD Analysis, 10-7-1988**]; **NOX**: (INTERIM) 44 LBS/MMCF (1) [RULE 2012, 5-6-2005]; **NOX**: 15 PPMV (8) [40 CFR 60 Subpart KKKK, 6-6-2006]; **PM**: 11 LBS/HR (5) [RULE 476, 10-8-1976]; **PM**: 0.01 GRAINS/SCF (5A) [RULE 476, 10-8-1976]; **PM**: 0.1 GRAINS/SCF (5B) [RULE 409, 8-7-1981] **SOX**: (INTERIM) ~~0.80~~ 2.02 LBS/MMCF (1) NATURAL GAS [RULE 2011, 5-6-2005]; **SOX**: (INTERIM) 5.07 LBS/MMCF (1) REFINERY GAS [RULE 2011, 5-6-2005]; **SOX**: 0.06 LBS/MMBTU (8) [40 CFR 60 Subpart KKKK, 6-6-2006]; **SO2**: (9) [40CFR72 – ACID RAIN] **VOC**: 2 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1)-BACT, 12-6-2002]*	A63.X1, A63.X2, A99.X2, A99.X3, A99.X4, A99.X5, A99.X6, A99.X7, A195.X2, A195.X3, A195.X4, A195.X5, ~~A248.X1, A248.X2, A248.X3, A248.X4~~, A327.2, A433.X1, B61.X1, B61.X2, C1.X2, D12.X1, D29.X1, D29.X3, D29.X4, D82.X1, D82.X2, D90.X1, D90.X2, I296.X1, H23.X2, K40.X, K67.X1
BOILER, TURBINE EXHAUST HEAT RECOVERY, UNFIRED, 624,000 LBS/HR STEAM A/N: 496922	DX4				

STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR, RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1228				
STEAM TURBINE, STEAM, DRIVING 42.78 MVA ELECTRIC GENERATOR RATED @ 37.5 MW, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1229				
CONDENSER, STEAM SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1231				
CONDENSER, STEAM, SURFACE, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D1232				
HEAT EXCHANGER, BUTANE VAPORIZER, RPV 4830, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2111				
DRUM, KNOCK OUT, BUTANE, RPV 4831, COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~); HEIGHT: 11 FT; DIAMETER: 5 FT 6 IN A/N ~~411169~~ 508471	D2112				
HEAT EXCHANGER, BUTANE SUPERHEATER, RPV 4832, (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2113				
COMPRESSOR, NO. 1, RW-0045-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3 & 4~~) A/N ~~411169~~ 508471	D2740				

COMPRESSOR, NO. 2, RW-0046-087.32, 10,700 SCFM (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~) A/N ~~411169~~ 508471	D2775				
DRUM, RPV-4800, SLOP COLLECTING (COMMON TO ALL COGENERATION UNITS ~~NO. 1, 2, 3, & 4~~), HEIGHT: 9 FT; DIAMETER: 4 FT A/N ~~411169~~ 508471	D2741				
System 10: AIR POLLUTION CONTROL SYSTEM NO. 5					S7.X1, S7X2
SELECTIVE CATALYTIC REDUCTION, NO. 5, WITH AMMONIA INJECTION, CORMETECH OR EQUIVALENT, ~~1600 CU. FT.~~ A/N 496924 AMMONIA INJECTION	CX1	DX1 DX2 CX2		**NH3:** 5 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996**; *RULE 1303(a)(1)-BACT, 12-6-2002*]	A99.X1, 195.X1, D12.X2, D12.X3, D12.X4, D29.X2, E57.X1, E73.X1
REACTOR, CARBON MONOXIDE OXIDATION, APC NO. 5, ENGELHARD OR EQUIVALENT, ~~1600 CU. FT.~~ A/N 496924	CX2	~~DX1 DX2~~ CX1			D12.X5
AMMONIA INJECTION A/N 496924	CX3				
STORAGE TANK, HORIZONTAL, 44' 11" L x 7' DIA; WITH VAPOR RETURN LINE, AQUEOUS AMMONIA, 12000 GALS A/N 508474	DX3				C157.X, E144.X
STACK, EXHAUST SYSTEM SERVING SCR NO. 5, HEIGHT: 100 FT; DIAMETER: 15 FT 6 IN A/N 496924	SX1	~~DX1 DX2~~ ~~CX1~~ CX2			

BACKGROUND

BP West Coast Products LLC (BP) submitted Application Numbers (A/Ns) 496922, 496924, and 496925 on March 26, 2009 to the South Coast Air Quality Management District (SCAQMD) seeking Permits to Construct (PC) for a gas turbine cogeneration system and air pollution control system. A/N 496922 is associated with the gas turbine cogeneration unit, A/N 496924 is associated with the air pollution control system, and A/N 496925 is for revision of the RECLAIM/Title V permit issued to the facility. On February 26, 2010 BP submitted A/N 508474 for a PC for an aqueous ammonia storage tank serving the new air pollution control system. Also on February 26, 2010 BP submitted A/Ns 508456, 508471, 508472, and

508473 seeking PCs for existing Cogeneration Unit Nos. 1, 2, 3, and 4. The PCs for Cogeneration Units 1 through 4 involve changes to conditions in existing permits. The project has been entitled the "Watson Cogeneration Steam and Electric Reliability Project." The Watson Cogeneration Company (Watson) has constructed and operated four cogeneration units, since 1988, at a site within the BP Carson Refinery. Watson is a joint partnership between subsidiaries of BP America and Edison Mission Energy. The existing cogeneration facility consists of four General Electric (GE) 7EA Combustion Turbine Generators (CTG), four Heat Recovery Steam Generators (HRSG), and two steam turbine generators (STG).

PCs are now sought for a fifth cogeneration train, or "fifth train," which includes a CTG/HRSG and air pollution control system. The new cogeneration unit will increase the electric generating capacity of the facility by approximately 85 $MW_{e,}$ from 385 MW_e to 470 MW_e. The cogeneration unit will supply electric power and steam to the refinery and will export excess power generated to the electric utility grid. It will increase the reliability of the Watson facility, reducing the risk of refinery upset due to loss of power. The project will also ensure that the refinery's steam demand is fully met, even when one or two of the existing CTG/HRSGs are out of service. The new cogeneration unit will be operated as a baseload unit and is expected operate 365 day per year, with an expected capacity factor exceeding 95%. The new air pollution control equipment includes a Selective Catalytic Reduction (SCR) system, for NO_x control, and a CO Oxidation Catalyst Reactor, for control of CO and VOC. The California Energy Commission (CEC) is the lead agency under the California Environmental Quality Act (CEQA) and has the authority to certify of the project. BP's application submittal to the SCAQMD is in conjunction with an Application for Certification (AFC), submitted to the CEC (Docket 09-AFC-01). The CEC determined on July 29, 2009 that the AFC is complete. The original project schedule called for construction to begin in May 2010 and for commercial operation to commence in June 2012.

The project will be evaluated as a significant revision to the existing Title V permit issued to the BP Carson Refinery (Facility ID: 131003). The project is also subject to NO_x and SO_x RECLAIM. Prevention of Significant Deterioration (PSD) – Regulation XVII applies to this equipment, but the project is exempt from requirement of a PSD analysis under District Rule 1703 since it does not result in a "Significant Emissions Increase" as defined in Rule 1702. The new cogeneration unit is also a major modification to a major stationary source under Regulation XIII and as such is subject to the full requirements of New Source Review. Other major environmental regulations which apply to the new project are 40CFR72 – Acid Rain, 40CFR60 Subpart KKKK – New Source Performance Standards for Gas Turbines, and District Rule 1401 – Toxics.

Cogeneration Unit Nos. 1, 2, 3, and 4 are currently permitted in the BP Title V permit. Under this set of applications, BP seeks to amend permit conditions to accommodate a fifth cogeneration unit. BP seeks to amend the description of equipment which is common to four cogeneration units (e.g. steam turbines, steam condensers, etc…), to indicate that the equipment will be "common to all cogeneration units" (i.e. including the fifth cogeneration unit). Additionally, BP seeks to add a permit condition limiting emissions of Particulate Matter ~~(PM)~~ with an aerodynamic diameter of less than 10 microns (PM_{10}) from all five cogeneration units. A new condition will limit emissions from five cogeneration units, to a total of 1243 lbs PM_{10}/day. This PM_{10} emissions rate is the current limit stated in the CEC permit for the four existing cogeneration units, minus 1 lb PM_{10}/day (note: the requirement of emissions reduction from pre-modification conditions is based on a communication from Jay Chen – SCAQMD Senior Air Quality Engineering Manager, dated May 20, 2010). The CEC limit is stated for total PM emissions, which for gas fired combustion devices is regarded as being equal to PM_{10} emissions (note: emissions testing performed at BP/Watson Cogeneration Company does not differentiate between total PM and PM_{10} emissions). Finally, the permit will be amended to remove reference to Boiler No. 42, which has being eliminated from the Title V permit. BP requested inactivation of the Boiler No. 42 permit in a communication to the District on February 19, 2010. BP stated that this equipment is no longer in service. Since Boiler No. 42 (Device ID: D1262) has been removed from the permit, conditions E17.1 and E226.1, which pertain to the operation of Boiler No. 42, will be eliminated.

The application/permit history of the existing cogeneration units follows in the table below:

Application/Permit History of Existing Cogeneration Units

Application No.	Process No.	System No.	Previous P/O	Date	Permit History
508456	17	1	411168/F81539 395992/ 308840/PC 287882/D90345 145968/ D78128	4/12/2006 5/20/1996 4/28/1995 11/2/1993	Cogeneration Unit No. 1 is currently permitted under Permit No. F81539 (A/N 411168) issued on April 12, 2006. This application involved an administrative change to add devices common to all cogeneration units (D2111, D2113, D2114, D2740, D2741, and D2742) to the permit. BP West Coast Products LLC submitted A/N 395992 for Change of Ownership of the subject equipment. This application remains Status 21 (i.e. application processing was not completed). Previously, a PC was issued for this equipment under A/N 308840 on May 20, 1996. Under this application, the gas turbine butane system was modified. This modification consisted of listing existing unpermitted equipment and addition of new equipment. Previously, the equipment was permitted under Permit No. D90345 (A/N 287882) issued on April 28, 1995. Under this application, the duct burner was modified to a larger capacity unit, increasing from 260 MMBtu/hr to 340 MMBtu/hr. Previously, the equipment was permitted under Permit No. D78128 (A/N 145968) issued on November 2, 1993. Under this application, the equipment was originally constructed and operated.
508471	17	2	411169/F81540 396119/F49910 287884/D90505 145969/ D78125	4/12/2006 3/11/2002 4/28/1995 11/2/1993	Cogeneration Unit No. 2 is currently permitted under Permit No. F81540 (A/N 411169) issued on April 12, 2006. This application involved an administrative change to add devices common to all cogeneration units (D2111, D2113, D2114, D2740, D2741, and D2742) to the permit. Previously, this equipment was permitted under Permit No. F49910 (A/N 396119) issued on March 11, 2002. Under this application the equipment underwent Change of Ownership, from ARCO Products Co. to BP West Coast Products LLC. Previously, the equipment was permitted under Permit No.

				D90505 (A/N 287884) issued on April 28, 1995. Under this application, the duct burner was modified to a larger capacity unit, increasing from 260 MMBtu/hr to 340 MMBtu/hr. Previously, the equipment was permitted under Permit No. D78125 (A/N 145969) issued on November 2, 1993. Under this application the equipment was originally constructed and operated.
508472	17	3	411170/F82071 5/11/2006 396033/F49909 3/11/2002 287885/D90506 4/28/1995 145970/ D78126 11/2/1993	Cogeneration Unit No. 3 is currently permitted under Permit No. F82071 (A/N 411170) issued on May 11, 2006. This application involved an administrative change to add devices common to all cogeneration units (D2111, D2113, D2114, D2740, D2741, and D2742) to the permit. Previously, the equipment was permitted under Permit No. F49909 (A/N 396033) issued on March 11, 2002. Under this application the equipment underwent Change of Ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, the equipment was permitted under Permit No. D90506 (A/N 287885) issued on April 28, 1995. Under this application, the duct burner was modified to a larger capacity unit, increasing from 260 MMBtu/hr to 340 MMBtu/hr. Previously, the equipment was permitted under Permit No. D78126 (A/N 145970) issued on November 2, 1993. Under this application the equipment was originally constructed and operated.
508473	17	4	411171/F81544 4/12/2006 396032/F49912 3/11/2002 287886/D90507 4/28/1995 145971/ D78127 11/2/1993	Cogeneration Unit No. 4 is currently permitted under Permit No. F81544 (A/N 411171) issued on April 12, 2006. This application involved an administrative change to add devices common to all cogeneration units (D2111, D2113, D2114, D2740, D2741, and D2742) to the permit. Previously, the equipment was permitted under Permit No. F49912 (A/N 396032) issued on March 11, 2002. Under this application the equipment underwent Change of Ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, the equipment was permitted under Permit No. D90507 (A/N 287886) issued on April 28, 1995. Under this application, the duct burner was modified to a larger capacity unit, increasing from 260 MMBtu/hr to 340 MMBtu/hr. Previously, the equipment was permitted under Permit No. D78127 (A/N 145971) issued on November 2, 1993. Under this application the equipment was originally constructed and operated.

A search of District records indicates that there have been no Notices of Violation (NOV)s or Notices to Comply (NTC)s associated with the existing cogeneration facility over the past three years.

PROCESS DESCRIPTION

The Watson Cogeneration Company has operated a combined cycle cogeneration facility, rated at 385 MWe on a 21.7 acre parcel site within the BP Carson Refinery, since 1988. The facility supplies electric power and process steam to the BP Refinery, with excess electricity delivered to the electric utility grid. Normal power output of the facility (including two steam turbines) is 344 MWe, with a peak output of 385 MWe. BP now proposes to construct a new cogeneration unit, the fifth train, which will have a rating of 85 MWe, net. The four existing cogeneration units each consists of a General Electric Frame 7 gas turbine (Model No. PG7111EA). Each gas turbine is site rated at 82.72 MWe and has a heat input rating of 985.5 MMBtu/hr. The gas turbines are permitted to fire natural gas, refinery gas, and butane. Exhaust gas from each cogeneration unit passes through a Heat Recovery Steam Generator (HRSG), which produces process steam. Each HRSG is equipped with a 340 MMBtu/hr John Zink duct burner firing refinery gas or natural gas, to enhance steam production. Each HRSG has a capacity to produce 583,000 lbs/hr of steam at 625 psig and 21,400 lbs/hr of steam at 150 psig. In practice, the steam from each HRSG is fed to a 600 psig steam header. The air pollution control equipment includes steam/water injection into the combustion turbines for NO_x control, Selective Catalytic Reduction (SCR) systems for additional NO_x control, and oxidation catalysts for control of CO and VOC. The existing facility is designed to meet the following pollutant emissions levels: 8 ppm NO_x (@ 15% O_2), 2.5 ppm CO (@ 15% O_2), and 2 ppm SO_x (@ 15% O_2). The facility is equipped with continuous monitors for NO_x/CO emissions, exhaust O_2 concentration, and fuel flow and ammonia input rates. The equipment operates 24 hours per day, 7 days per week, and 52 weeks per year.

The Title V permit issued by the SCAQMD does not state pollutant mass emissions limits for Cogeneration Unit Nos. 1 through 4. However, the CEC permit for this equipment states limits for total emissions from the four units, as follows: 2600 lbs NO_x/day, 568 lbs CO/day, 531 lbs ROG/day, 1244 lbs PM/day, and 246 lbs SO_2/day.

The new cogeneration unit is the fifth unit, and is rated at 85 MW, net (maximum output during winter months is 94 MW, net). The project equipment includes a General Electric (Model 7EA) CTG with inlet fogging system, one duct fired HRSG, two redundant natural gas compressors, one boiler feedwater pump, one circulating water pump, two new cells added to an existing cooling tower, an electrical distribution system, instrumentation and controls, and auxiliary equipment. The project will make use of the existing supplies of natural gas, water, and compressed air at the cogeneration facility. The CTG will fire a blend of natural gas and refinery fuel gas, with the refinery fuel gas accounting for up to 35 % by volume of fuel fired, while the duct burner in the HRSG is expected to fire mostly refinery gas. The new equipment is expected to operate 24 hours per day, 7 days per week, and 52 weeks per year.

The new CTG equipment includes compressors, a combustor, and a power turbine. Natural gas from the existing Southern California Gas Company (SoCalGas) system is compressed in two new reciprocating compressors to levels required by the Dry Low NO_x (DLN) combustor (350 psig at all times). The DLN combustor is expected achieve a NO_x concentration of 9 ppm, corrected to 15% O_2. The DLN combustor achieves this by premixing fuel and air, prior to entering the combustion chamber, thus providing greater combustion control. The CTG will also combust refinery fuel gas; the quantity dependent on the manufacturer's requirement for gas quality and how much refinery fuel gas, meeting Best Available Control Technology (BACT) standards for sulfur content, can be produced by the refinery fuel gas system. A can-annular combustor is used to combust the fuel. The combustion products, at a temperature of 2600°F, are fed to a turbine which expands and cools them (i.e. converts the heat energy into mechanical energy). The mechanical energy of the turbine is used to drive an electric generator. At full load the synchronous alternating current (AC) generator will produce 85 MW_e of electric power at 13.8 kV. The generator will be a three-phase two-pole air-cooled unit with brushless exciter. The cogeneration unit is also equipped with a Heat Recovery Steam Generator (HRSG) to generate steam from the sensible heat in the CTG exhaust gas. When CTG exhaust gas temperature is insufficient for steam generation, a duct burner with a rated heat input of 510 MMBtu/hr, provides additional heat to the process. The duct burner will be supplied by John Zink (or equivalent) and will have two rows of low-NO_x burners. The HRSG is a natural circulation unit capable of producing 624,000 lbs/hr steam at a temperature of 924°F. The steam will be delivered to the existing 600 psig steam header shared by the four existing cogeneration units. Thus, the HRSG does not directly generate electricity, but produces steam which may be used in existing STG for electric power generation.

The new CTG/HRSG will include equipment for continuous monitoring of exhaust concentrations of NO_x, SO_2, CO, and O_2 and injection rates of fuel gas and NH_3. The CTG/HRSG vents to a new stack, with a height of 100 feet and diameter of 15 ft 6 inches. At full load, the exhaust gas volumetric flow rate will be 864,383 cfm, at a temperature of 385°F.

Process flow values for the full load operating condition of the new cogeneration unit are described in the table below:

Process Flow Values - Fifth Cogeneration Unit

Net Facility Output, kW	89,999
Net Heat Rate, Btu/kW-hr, LHV	15,150
Combustion Turbine Natural Gas Flow, lbs/hr	31,497
Combustion Turbine Refinery Gas Flow, lbs/hr	16,959
Duct Burner Refinery Gas Flow, lbs/hr	22,362
Total Heat Input, MMBtu/hr, LHV	1,363.5
Vaporized Ammonia, lbs/hr	31
Boiler Feedwater, lbs/hr	655,630
Desuperheated Steam to Watson Steam Header, lbs/hr	680,844

Note: Data from Case E-3 in Application for Certification

The new air pollution control system will include a Selective Catalytic Reduction (SCR) unit to control nitrogen oxides (NO_x) emissions and an oxidation catalyst to control CO and VOC emissions. The equipment supplier for the SCR and CO oxidation catalyst has not yet been decided upon. The SCR will utilize aqueous ammonia from a new dedicated aqueous ammonia storage tank. A new 12,000 gallon horizontal storage tank (diameter: 7 ft, length: 44 ft 11 in) will store aqueous ammonia. The tank will be equipped with a vapor return line to capture ammonia during loading activities. The tank will be equipped with a breather vent, with a vacuum setting of 30 psig and a pressure setting of 30 psig. Based on a capacity factor of 95% and an ammonia concentration of 19 wt%, the annual ammonia requirement will be

181,040 gallons/yr (31 lbs NH_3/hr x 24 hrs/day x 365 days/yr x 0.95 / 0.19 NH_3/lb solution x 7.50 lb/gal). This is equivalent to 17.7 turnovers per year (181,040 gal/yr / 12,000 gal x 0.85 max fill ratio), requiring approximately 31 deliveries of ammonia per year (based on delivery tank capacity of 6,000 gallons). The ammonia injection system will include a two stage ammonia air blower, vaporizer, and an ammonia injection grid to inject ammonia in front of the SCR catalyst. The catalysts to be used in the SCR/CO oxidation catalyst have yet to be determined, but may be composed of vanadium/titanium in a plate or honeycomb design. The proposed design parameters are as follows; length: 1 foot 8.5 inches; width: 25 feet; height: 38 feet; total volume: 1583 cubic feet; total weight: 65,000 lbs; space velocity: 72,000 hr^{-1}; area velocity: 175 feet/hour; catalyst life: 3 years; minimum SCR inlet temperature: 680°F; maximum SCR inlet temperature: 800°F; and warm-up time: 3 hours. The air pollution control system will control pollutant emissions to the following BACT levels (all corrected to 15% O_2): 2.0 ppm NO_x (1-hour average), 2 ppm CO (3-hour average) and 3.0 ppm CO (1-hour average), 2 ppm VOC (1-hour average), and 5 ppm ammonia (1-hour average).

In addition to the equipment described above, two new cooling tower cells will be added to the existing seven cell cooling tower. The system will also include a new centrifugal circulating water pump. This will provide heat rejection for the existing two condensing steam turbine generators. The cooling tower modification is exempt from permitting by the SCAQMD, under Rule 219(d)(3).

The BP Carson Refinery is in an area zoned Commercial Manufacturing (C-M). It is in an urban area (area of dense population). The facility is not located within 1000 feet radius of the outer boundary of a school. The distance from the equipment to the nearest residence is 3450 feet and to the nearest business is 1190 feet.

EMISSION CALCULATION

The potential-to-emit of criteria pollutants from Cogeneration Unit Nos. 1, 2, 3, and 4, has been calculated under previous applications. The current project, to amend the equipment description and to add a PM_{10} emissions limitation, does not result in a change in criteria or Toxic Air Contaminant (TAC) emissions. Since there is no potential for a change in TAC emissions from Cogeneration Unit Nos. 1, 2, 3, and 4, TAC emissions from these units are not quantified in this evaluation.

Table 1. Cogeneration Unit Nos. 1, 2, 3, and 4 – Potential-to-Emit of Criteria Pollutants

Pollutant	Maximum Hourly Uncontrolled Emissions (lbs/hr)	Maximum Hourly Controlled Emissions (lbs/hr)	Maximum Daily Controlled Emissions (lbs/day)	Emissions (lbs/day – 30 day average)
NO_x	270.83	27.08	650	672
CO	59.17	5.92	142	147
VOC	10.92	5.46	131	135
SO_x	6.58	3.29	79	82
PM_{10}	12.96	12.96	311	321

Notes: 1. Maximum Daily Controlled Emissions are those calculated under Modification Applications, A/Ns 287882, 287884, 287885 and 287886.
2. Maximum Hourly Controlled emissions are Maximum Daily Controlled emissions divided by 24 hours/day.
3. Maximum Hourly Uncontrolled emissions are calculated from Maximum Daily Controlled emissions and control efficiencies of 90% for NO_x and CO and 50% for VOC. Additionally, 50% of SO_2 is converted to SO_3 in the catalyst, therefore uncontrolled emissions are double of controlled emissions. Uncontrolled PM_{10} emissions are equal to controlled emissions.
4. Emissions (lbs/day – 30 day average) are equal to maximum monthly emissions (over 744 hours) divided by 30.

Criteria pollutant and TACs emissions from operation of the new CTG/HRSG are quantified below.

Criteria pollutant emissions expected from the fifth cogeneration unit during the one-time commissioning period are presented below. The commissioning period involves part-load and full-load operation, for the purpose of tuning the combustion turbine and emissions control system. Peak emissions during this period are expected to be higher than those from normal operation. The commissioning period will require approximately 550 hours of operation, over a period of three months. Commissioning activities are described in Attachment #1.

Table 2. Estimated CTG/HRSG Emissions Rates During Commissioning

Pollutant	Maximum Hourly Emissions (lbs/hr)	Emissions During 550 Hours of Commissioning Activities (tons)
NO_x	211	20.0
CO	255	23.6
VOC	5	1.4
SO_x	4	0.6
PM_{10}	12	1.6

Criteria pollutant emissions from the new CTG/HRSG for steady state/full load operation and are tabulated below.

Table 3. CTG/HRSG Emissions Rates – Steady State, Full Load

Pollutant	Basis – Concentration Limit or Emissions Factor	Maximum Hourly Uncontrolled Emissions (lbs/hr)	Maximum Hourly Controlled Emissions (lbs/hr)	Maximum Daily Controlled Emissions (lbs/day)
NO_x	2 ppmvd (1-hour avg)	64.56	11.94	286.6
CO	3 ppmvd (1-hour avg) 2 ppmvd (3-hour avg)	81.64	10.91	174.5
VOC	2 ppmvd (1-hour avg)	11.85	4.16	99.8
SO_x	Natural Gas: ~~0.29~~ 0.75 gr/100 cf; Refinery Fuel Gas: 40 ppm (3-hour avg); 30 ppm H_2S (24-hour avg)	~~5.87~~ 6.74	~~5.87~~ 6.74	~~109.0~~ 129.7
PM_{10}	<=0.00661 lbs/MMBtu	9.93	9.93	238.3
NH_3	5 ppmvd (1-hour avg)	11.05	11.05	265.2

Notes: 1. Emissions data are from for Case E-3 in the Application for Certification, Ambient Temperature = 36°F, Relative Humidity = 36%, Maximum Firing of CTG and DB.
2. For CO, hourly controlled emissions are based on 3 ppm CO limit; daily controlled emissions based on 2 ppm CO limit.
3. For SO_2, hourly uncontrolled/controlled emissions based on 40 ppm H_2S limit for refinery fuel gas; daily controlled emissions based on 30 ppm H_2S limit for refinery fuel gas.
4. No startup/shutdown emissions in hourly or daily emissions.
5. Controlled emissions based on the following removal/control efficiencies: NO_x = 81.5%, CO = 91.1%, VOC = 64.9%. These control efficiencies are based on expected uncontrolled emissions – provided by equipment supplier – controlled to BACT limits.
6. PM_{10} emissions rates are from manufacturer estimates, not guarantees, for the CTG (GE) and duct burner (John Zink).
7. PM_{10} emissions for all five cogeneration units will be capped at 1243 lbs/day, which is current limit for PM from the four existing units stated in the CEC permit, minus 1 lb PM_{10}/day. The CEC limit is consistent with the District's evaluation under A/N 287882, in which PM_{10} emissions from each cogeneration unit were limited to 311 lbs/day, when all four cogeneration units were in operation.

Criteria pollutant emissions from the new CTG/HRSG during cold startup, warm startup, and shutdown are tabulated below.

Table 4. CTG/HRSG Emissions Rates – Startup/Shutdown Periods

Parameter/Mode	Cold Startup	Warm Startup	Shutdown
NO_x, lbs/event	211.24	21.32	12.85
CO, lbs/event	300.65	58.72	57.60
VOC, lbs/event	9.95	2.61	4.11
PM_{10}, lbs/event	30.0	7.16	9.34
SO_x, lbs/event	20.52	3.18	5.95
Event Time, minutes, (hours)	180 minutes (3 hours)	60 minutes (1 hour)	60 minutes (1 hour)
Number of Events/Year	4	~~12~~ 24	~~16~~ 29

Notes: 1. Turbine startup on natural gas only.
2. During the three hour cold startup, BACT level emissions are expected during the transition from hour 2 to hour 3. DLN combustors operating at 50% of turbine load.
3. Warm startup assumes 26 minutes of full load operation with maximum duct burner firing.
4. Shutdown event assumes that turbine is operating at full load with maximum duct burner firing for 52 minutes prior to shutdown.

The maximum criteria pollutant emissions from the new CTG/HRSG (cold startup, warm startup, shutdown, or steady state/full load operation) are tabulated below.

Table 5. CTG/HRSG Maximum Emissions Rates (cold startup, warm startup, shutdown, or steady state/full load whichever is highest)

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Maximum Annual Emissions (tons/year)
NO_x	175.0	637.40	39.9
CO	210.0	732.16	~~33.1~~ 37.8
VOC	4.16	99.84	18.2
SO_x	~~5.87~~ 6.74	~~109.0~~ 129.7	19.9
PM_{10}	9.93	238.3	43.5

Notes:
1. The worst case day for NO_x and CO is defined as two cold startups (initial cold start failure then a restart for a total of six hours) plus 18 hours of full load operation.
2. The worst case day for VOC, SO_2, and PM_{10} is based on 24 hours of operation at full load.
3. Hourly SO_2 emissions based on 40 ppm H_2S limit for refinery fuel gas; daily and annual emissions based on 30 ppm H_2S limit for refinery fuel gas.
4. Annual emissions of NO_x and CO assumes ~~8,720~~ 8,695 hours with duct firing, plus four cold startups (12 hours), ~~12~~ 24 warm startups (24 hours), and ~~16~~ 29 shutdowns (29 hours) per year. Annual emissions ~~of NO_x~~ are calculated using emissions from Annual Average Case, of Temperature = 63.1°F and Relative Humidity = 60% (See Attachment #2). This permit (condition S2.X1) includes an annual NO_x emissions limit of 39.9 tons (note: using the worst case full load hourly NO_x emissions rate of 11.94 lbs/hr over 8760 hours, annual NO_x emission rate of 52.3 tons/year is calculated). NO_x emissions will be monitored and reported through the District's RECLAIM program.
5. Annual emissions of VOC, SO_2, and PM_{10} are based on 8760 hours of operation at full load.
6. Annual emissions of SO_2 are calculated using an annual average total sulfur content of 0.29 gr/100 cf for natural gas.
7. Total annual emissions of VOC, from CTG/HRSG operation and from fugitive components, are 27.6 tons/year (note: potential-to-emit of VOC from fugitive components is calculated in Table 6, below).

In the original application submittal to the SCAQMD, BP proposed to limit the refinery fuel gas total sulfur concentration, to 40 ppm, calculated as H_2S (i.e. BP proposed this as a BACT limit). The SCAQMD notified BP in an e-mail on July 2, 2009 that other recent projects involving cogeneration units fired with refinery fuel gas, have been permitted with a BACT limit of 30 ppm. Therefore, permit limits of refinery fuel gas total sulfur content of 40 ppm as H_2S (3-hour average) and 30 ppm as H_2S (24-hour average) are imposed in this permit.

Fugitive VOC emissions from components are tabulated below. This is based on the fugitive component count specific to the fifth train.

Table 6. VOC Emissions Due to Fugitive Components in New Cogeneration Unit

Source Unit		Service	Emission Factor (lbs/yr)	Component Count	Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	0.0	535	0.0
	SCAQMD Approved I & M Program	Fuel & Natural Gas	12	0	0.0
		Gas/Vapor	23	42	966.0
		Light Liquid	19	13	247.0
		Heavy Liquid	3	4	12.0
Pumps	Sealless Type	Light Liquid	0	0	0.0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	104	1	104.0
	Single Mechanical Seal	Heavy Liquid	80	1	80.0
Compressors		Gas/Vapor	514	1	514.0
Flanges and Connectors		All	1.5	2,153	3,229.5
Pressure Relief Valves		All	0	8	0.0
Process Drains with P-Trap and Seal Pot		All	80	169	13,520.0
				Emissions, Lbs/yr	18,672.5
				Emissions, Lbs/day	51.2
				Emissions, Lbs/hr	2.13

Notes:
1. Light liquid and gas/liquid streams: Liquid and gas/liquid stream with a vapor pressure greater than of kerosene (>0.1 psia @ 100 deg F of 689 Pa @ 38 deg C), based on the most volatile class of liquid at >20% by volume.
2. The non-bellows seal valves (BSV) include valves in instrumentation service, control valve, and drains that are exempt from BSV requirement.
3. This is the final count. No margin was added.
4. Flange Count Basis:
   a. Flow Orifice = 2 flanges
   b. Flange Valve = 2 flanges; 3 with spectacle blind
   c. All Valves < or = 1" are socket welded installations – no flanges

Emissions offsets required for permitting of the new cogeneration unit are tabulated below. Emissions increase (lbs/day – 30 day average) is calculated from maximum monthly emissions divided by 30 days. Maximum monthly emissions are based on 744 hours of full-load operation.

Table 7. Emissions Offsets Calculation for the new Cogeneration Unit

Pollutant	Emissions Increase (lbs/day – 30 day average)	Offset Ratio	Emissions Offsets Required (lbs/day)	Source of Emissions Offsets
PM_{10}	246	1.2	295	Rule 1304 Exemption – Concurrent Facility Modification
VOC	156	1.2	187	ERCs

BP proposes to mitigate PM_{10} emissions from the new cogeneration unit by limiting PM_{10} emissions from this unit and the existing four cogeneration units, to 1243 lbs/day (equal to the limit of 1244 lbs/day stated in the CEC permit, minus 1 lb PM_{10}/day). A permit condition is included (see proposed permit condition

A63.X2) for this limitation. For compliance with Reg XIII, the facility will use an exemption from offsets, associated with Concurrent Facility Modification (1304(c)(2)).

Per condition I296.1, the facility will be required to demonstrate that it holds, at the beginning of each compliance year, sufficient RECLAIM Trading Credits (RTC)s sufficient to cover the annual increases in NO_x and SO_x, as shown in the table below.

Table 8. RECLAIM Trading Credit (RTC) Calculation for the new Cogeneration Unit

Pollutant	Offset Basis	Emissions (lbs)	Offset Ratio	Required RTCs
NO_x	Annual Emissions During 1st 12 Months	99,850	1.0	99,850
NO_x	Annual Emissions After 1st 12 Months	79,800	1.0	79,800
SO_x	Annual Emissions During 1st 12 Months	31,050	1.0	31,050
SO_x	Annual Emissions After 1st 12 Months	39,770	1.0	39,770

Note: First year emissions are sum of emissions during commissioning period and 9 months of normal operation.

Attachment #4 presents emissions factors for VOC and PM_{10}, which are used in proposed permit conditions A63.X1 and A63.X2. For calculation of VOC emissions under condition A63.X1, a factor of 2.64 lbs VOC/MMscf for natural gas is stated. For refinery gas a formula of 2.94E-7 x F_d-Factor x GCV_v is proposed, where F_d-Factor is a factor representing the ratio of volume of products of combustion to the heat content of the fuel (dry basis @ 0% excess oxygen) and GCV_v is the gross calorific value of refinery gas in units of Btu/scf. These are based on VOC emissions of 2 ppm @ 15% O_2, which will be verified through periodic source testing. The facility will be required to use monthly averages of F_d-Factors and GCV_v for refinery gas, with this formula. A formula for calculation of VOC emissions from refinery gas combustion is proposed since the fuel characteristics of refinery gas varies frequently and will not be consistent as stated in the AFC application. Table I-A-5 of the AFC application states that the refinery gas is "Based on a grab sample dated 11/28/2008, provided by the refinery and having a heating value at the low end of the range of grab samples for year 2008." The method of calculation of VOC emissions in condition A63.X1 is consistent with the VOC emissions rate stated in Table 3, above.

Emission rates of Toxic Air Contaminants (TAC)s from the new CTG/HRSG are tabulated below. These were calculated using emissions factors for combustion of natural gas and refinery gas, approved by the California Air Resources Board (CARB) and the USEPA. The Health Risk Assessment (HRA), based on these calculated TAC emissions rates, determined that the MICR associated with the project is under $10x10^{-6}$ and that hazard indices are under 1.0. This HRA, performed by the applicant, was reviewed by SCAQMD staff and found to be consistent with SCAQMD HRA procedures.

Table 9. Emissions of Toxic Air Contaminants from new CTG/HRSG

Compound	**Turbine EF Natural Gas lbs/MMscf**	**Turbine EF Refinery Gas lbs/MMscf**	**HRSG/DB EF Natural Gas lbs/MMscf**	**HRSG/DB EF Refinery Gas lbs/MMscf**	**OPS Option 1 lbs/hr**	**OPS Option 1 lbs/yr**	**OPS Option 2 lbs/hr**	**OPS Option 2 lbs/yr**	**OPS Option 3 lbs/hr**	**OPS Option 3 lbs/yr**
Acetaldehyde	4.08E-02	2.18E-02	8.87E-03	3.97E-03	4.39E-02	3.85E+02	3.77E-02	3.31E+02	3.98E-02	3.49E+02
Acrolein	6.53E-03	0.00E+00	0.00E+00	0.00E+00	6.75E-03	5.91E+01	4.57E-03	4.00E+01	4.57E-03	4.00E+01
Ammonia					7.80E+00	6.83E+04	7.80E+00	6.83E+04	7.80E+00	6.83E+04
Benzene	1.33E-02	1.49E-01	4.31E-03	2.60E-01	1.30E-01	1.14E+03	1.77E-01	1.55E+03	6.19E-02	5.42E+02
1,3-Butadiene	1.27E-04	0.00E+00	0.00E+00	0.00E+00	1.31E-04	1.15E+00	8.88E-05	7.78E-01	8.88E-05	7.78E-01
Ethylbenzene	1.79E-02	1.82E-03	0.00E+00	0.00E+00	1.85E-02	1.62E+02	1.31E-02	1.15E+02	1.31E-02	1.15E+02
Formaldehyde	7.24E-01	1.22E-01	2.21E-01	1.60E-02	7.55E-01	6.62E+03	5.55E-01	4.86E+03	6.44E-01	5.64E+03
Hexane	1.33E-03	0.00E+00	1.30E-03	0.00E+00	1.37E-03	1.20E+01	9.30E-04	8.15E+00	1.50E-03	1.31E+01
Naphthalene	1.66E-03	0.00E+00	1.99E-08	2.06E-04	1.81E-03	1.58E+01	1.25E-03	1.10E+01	1.16E-03	1.02E+01
Other Total PAHs	3.14E-04	2.62E-04	2.58E-08	2.41E-04	4.32E-04	3.79E+00	4.17E-04	3.65E+00	3.09E-04	2.71E+00
Propylene	7.71E-01	0.00E+00	1.55E-02	0.00E+00	7.97E-01	6.98E+03	5.39E-01	4.73E+03	5.46E-01	4.78E+03
Propylene Oxide	2.96E-02	0.00E+00	0.00E+00	0.00E+00	3.06E-02	2.68E+02	2.07E-02	1.81E+02	2.07E-02	1.81E+02
Toluene	7.10E-02	1.09E+00	3.40E-03	8.40E-01	4.50E-01	3.94E+03	7.97E-01	6.98E+03	4.22E-01	3.70E+03
Xylene	2.61E-02	3.14E+00	5.80E-03	0.00E+00	2.70E-02	2.36E+02	1.09E+00	9.51E+03	1.09E+00	9.54E+03
H_2S	0.00E+00	1.65E-01	0.00E+00	2.74E-01	1.23E-01	1.08E+03	1.79E-01	1.57E+03	5.61E-02	4.92E+02
Arsenic	0.00E+00	6.62E-05	2.00E-04	7.04E-04	3.16E-04	2.77E+00	3.38E-04	2.96E+00	1.10E-04	9.61E-01
Antimony	0.00E+00	6.62E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.25E-05	1.97E-01	2.25E-05	1.97E-01
Barium	0.00E+00	8.73E-04	4.40E-03	0.00E+00	0.00E+00	0.00E+00	2.97E-04	2.60E+00	2.21E-03	1.94E+01
Berylium	0.00E+00	2.05E-03	1.20E-05	1.55E-04	6.95E-05	6.09E-01	7.67E-04	6.72E+00	7.02E-04	6.15E+00
Cadmium	0.00E+00	7.41E-03	1.10E-03	2.38E-03	1.07E-03	9.35E+00	3.59E-03	3.14E+01	3.00E-03	2.63E+01
Chromium 6	0.00E+00	1.47E-04	1.40E-03	1.47E-04	6.59E-05	5.77E-01	1.16E-04	1.02E+00	6.60E-04	5.78E+00
Cobalt	0.00E+00	1.55E-02	8.40E-05	0.00E+00	0.00E+00	0.00E+00	5.27E-03	4.62E+01	5.31E-03	4.65E+01
Copper	0.00E+00	5.78E-02	8.50E-04	6.30E-03	2.82E-03	2.47E+01	2.25E-02	1.97E+02	2.00E-02	1.75E+02
Lead	0.00E+00	3.99E-02	0.00E+00	2.42E-03	1.09E-03	9.51E+00	1.47E-02	1.28E+02	1.36E-02	1.19E+02
Manganese	0.00E+00	1.80E-01	3.80E-04	2.39E-03	1.07E-03	9.39E+00	6.23E-02	5.46E+02	6.14E-02	5.38E+02
Mercury	0.00E+00	2.15E-02	2.60E-04	3.23E-04	1.45E-04	1.27E+00	7.46E-03	6.53E+01	7.43E-03	6.50E+01
Nickel	0.00E+00	2.33E-01	2.10E-03	5.59E-03	2.51E-03	2.20E+01	8.17E-02	7.16E+02	8.02E-02	7.02E+02
Selenium	0.00E+00	5.42E-03	2.40E-05	2.06E-03	9.24E-04	8.09E+00	2.77E-03	2.42E+01	1.85E-03	1.62E+01
Silver	0.00E+00	1.37E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.66E-05	4.08E-01	4.66E-05	4.08E-01
Thallium	0.00E+00	3.31E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.13E-05	9.86E-02	1.13E-05	9.86E-02
Vanadium	0.00E+00	0.00E+00	2.30E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.00E-03	8.78E+00
Zinc	0.00E+00	1.57E-02	2.90E-02	3.42E+00	1.53E+00	1.34E+04	1.54E+00	1.35E+04	1.80E-02	1.57E+02

Notes:

1. OPS Option 1: 100% Natural Gas fired in Turbine (1.0331 mmscfh) and 100% Refinery Gas fired in HRSG (0.44884 mmscfh)
2. OPS Option 2: 65% Natural Gas fired in Turbine (0.6996 mmscfh) and 35% Refinery Gas fired in Turbine (0.3401 mmscfh) and 100% Refinery Gas fired in HRSG (0.4484 mmscfh)
3. OPS Option 3: 65% Natural Gas fired in Turbine (0.6996 mmscfh) and 35% Refinery Gas fired in Turbine (0.3401 mmscfh) and 100% Natural Gas fired in HRSG (0.4358 mmscfh)
4. Emissions Factors are from CARB California Air Toxics Emissions Factor (CATEF) Database, EPA AP-42, Ventura County APCD, and BP data
5. Chromium VI Emissions Factor for Refinery Gas revised to 1.47×10^{-4} lbs/mmscf, from previous factor 2.04×10^{-3} lbs/mmscf (Refinery Gas fired in Turbine) and 7.770×10^{-3} lbs/mmscf (Refinery Gas fired in HRSG)

Emissions of ammonia from the ammonia storage tank are not expected to be significant. A calculation of the expected ammonia emissions rate is shown in Attachment #5. Controlled emissions are not expected to exceed 15.68 lbs/yr, or 0.044 lbs/day (30-day average).

RULE EVALUATION

CEQA: Since the project has a potential for significant adverse environmental impacts, the California Environmental Quality Act (CEQA) requires preparation of a document for evaluation of these impacts. The California Energy Commission (CEC) is the lead agency in the CEQA analysis. The CEC review will result in issuance of several environmental and decision documents. The CEC has a certified program under CEQA, which exempts it from having to prepare an Environmental Impact Report (EIR). The CEC review will include examination of public health and safety, environmental impacts, and engineering aspects of the proposed project.

Rule 212: This rule states cases under which issuance of a Public Notice is required. While the equipment is not located within 1000 feet of a school (see Attachment #8), Public Notice requirement is triggered since the Maximum Incremental Cancer Risk (MICR) associated with the new cogeneration unit has been determined to be greater than one in a million and emissions of criteria pollutants from the new cogeneration unit exceed limits stated in section 212(g). The applicant is required to ensure distribution of a Public Notice to each address within ¼ mile radius of the project. The Public Notice must include: information regarding availability of the SCAQMD analysis of the effect of the project on air quality - for public inspection in at least one location in the affected area, notice by prominent advertisement in the affected area of the location of source information and the SCAQMD analysis of the effect on air quality, mailing of such notice to USEPA Region IX / Air Resources Board / City and County, and provision of a 30 day period for submittal of public comments. ~~The Public Notice, project information submitted by the applicant, and the SCAQMD Permit to Construct evaluation will be made available for pubic review at the Carson Public Library, located at 151 E. Carson Street, Carson, CA, 90745.~~

The public notice was distributed to each address, within ¼ mile of the Watson Cogeneration Facility, on October 15, 2010. The SCAQMD reviewed this notice distribution and found it to be inadequate in that the notice should have been distributed to each address within ¼ mile of the BP Carson Refinery. Thus, the applicant re-distributed the public notice (both in English and Spanish language) to each address within ¼ mile of the BP Carson Refinery on October 29, 2010. The public notice was also published in two newspapers serving the area of the facility, La Opinion and Daily News Los Angeles, on October 15, 2010. The 30 day public comment period has concluded and no comments regarding the proposed permit were received from any member of the public. The public notice, project information submitted by the applicant, and the SCAQMD Permit to Construct evaluation were made available for pubic review at the Carson Public Library, located at 151 E. Carson Street, Carson, CA, 90745.

Rule 218: Under this rule, the facility is required to install, operate, and maintain in good working order a certified Continuous Emissions Monitoring System (CEMS) for CO. A facility is required to submit an "Application for CEMS" prior to installation of the CEMS. Within 90 days of installation, CEMS certification testing must be undertaken. Data from such tests must be submitted to the SCAQMD within 45 day. If results of testing are found to be satisfactory, the SCAQMD grants final approval of the CEMS. Submission of a CEMS QA/QC Plan within 45 days of installation and no later than 30 days prior to certification is also required. Reporting requirements include submittal to the SCAQMD of CEMS data every six months, reporting of concentrations and/or mass emissions in excess of regulatory limit, and reporting of breakdown or failure of the CEMS. The CO CEMS serving the new cogeneration unit will be installed and operated in accordance with the requirements of this rule.

Rule 401 Operation of Cogeneration Unit Nos. 1 through 4 and the new cogeneration unit is not expected to produce visible emissions with a shade as dark as or darker than that designated Ringelmann Number 1 by the U.S. Bureau of Mines, for a period of 3 minutes in any hour. Compliance with the requirements of this rule is expected.

Rule 402 This rule requires that a source not emit air contaminants which cause injury, detriment, nuisance, or annoyance to a considerable number of people or to the public, or which cause, or have a natural tendency to cause injury or damage to a business or property. Operation of the new cogeneration unit is not expected to result in a public nuisance. No public nuisance complaints, due to operation of the four existing cogeneration units, have been received over the past three years. Compliance with this rule is expected.

Rule 404 This rule states limitations of particulate matter concentration as a function of stack flow rate. However, per section 404(c), this rule does not apply to emissions from combustion of gaseous or liquid fuels in steam generators or gas turbines.

Rule 407 This rule states limits for a pollutant source of 2000 ppm CO (by volume on a dry basis averaged over 15 minutes) and 500 ppm SO_2 (averaged over 15 minutes). However, as stated in Rule 2001(j), the SO_x limitation under Rule 407 is not applicable to sources regulated under the SCAQMD SO_x RECLAIM program. Cogeneration Unit Nos. 1 through 4 and the proposed fifth cogeneration unit are designated "Major Sources" of SO_x under RECLAIM. The new cogeneration unit will be equipped with a CO oxidation catalyst, which will control the CO to a maximum of 2 ppm @ 15% O_2 (3-hour average) and 3 ppm @ 15% O_2 (1-hour average). The results of the 2008 source test of Cogeneration Unit Nos. 1 through 4, show that exhaust gases contain CO in the range of 1.03 ppm to 1.39 ppm (as found, dry basis) (Attachment #9 has summary tables for this source test). Compliance with the CO concentration limitation of this rule is expected.

Rule 409 This rule limits particulate matter emissions from combustion sources to 0.1 grains per cubic foot (calculated at 12% CO_2 and averaged over 15 minutes). As stated in the Emissions Calculation section, the potential-to-emit of particulate matter from the new cogeneration unit is 9.93 lbs/hr. Using the expected standard volumetric flow rate of 561,099 scfm, this emissions rate corresponds to a particulate matter grain loading of 0.0021 grains/scf @ ~ 3.67% CO_2 (or 0.0069 grains/scf @ 12% CO_2). The results of the 2008 source test of Cogeneration Unit Nos. 1 through 4 show that exhaust gases contain particulate matter with concentrations of 0.000342 to 0.000385 grains/dscf (as found). This is equal to a range of 0.00105 to 0.00116 grains/dscf (calculated at 12% CO_2) (Attachment #9). Compliance with the limitation of this rule is expected.

Rule 431.1 The public utility supplied natural gas to be fired in the cogeneration unit is expected to be in compliance with the 16 ppm sulfur limit (calculated as H_2S) imposed by this rule. This rule also limits the sulfur content of refinery fuel gas to a maximum of 40 ppmv sulfur, as H_2S. However, since SO_x emissions from the cogeneration units are subject to the SCAQMD SO_x RECLAIM program, this limitation does not apply to this equipment. For the new cogeneration unit, the applicant supplied emissions factor for natural gas of 0.75 grains S/100 scf corresponds to a sulfur concentration of 12 ppm sulfur, as H_2S. Further, the applicant states that over the long term, the sulfur content of natural gas fired in the new cogeneration unit is not expected to exceed 0.29 grains/100 scf.

Rule 475 This rule has requirements for electric power generating equipment with a maximum rating of more than 10 MWe net, for which a permit to build was required after May 7, 1976. The rule requires that combustion contaminants not exceed both of the following limitations: 11 lbs/hr (mass limit) and 0.01 gr/scf @ 3% O_2 (concentration limit). Compliance with this rule is achieved if either limitation is met. As stated in the Emission Calculation section, the potential-to-emit of particulate matter from the new cogeneration unit is 9.93 lbs/hr. This corresponds to a grain loading of 0.0021 grains/scf @ ~ 13.5% O_2 (equal to 0.0051 grains/scf @ 3% O_2) at full load operation. The results of the 2008 source test of Cogeneration Unit Nos. 1 through 4 show that exhaust gases contain particulate matter with concentrations of 0.000342 to 0.000385 grains/dscf (as found) and mass emissions rates of 1.52 to 1.65 lbs/hr (Attachment #9). Compliance with the requirements of this rule is expected and will be verified by periodic source testing.

Rule 476 This rule has requirements for steam generating equipment with a heat input rating of greater than 50 MMBtu/hr. The rule limits emissions of NO_x to 125 ppm @ 3% O_2, for gaseous fuel fired units. Per Rule 2001(j), since the existing and new cogeneration units are subject to the SCAQMD NO_x RECLAIM program, they are not subject to the NO_x limit under this rule. The rule also states limits for combustion contaminants of 11 lbs/hr (mass limit) and 0.01 gr/scf @ 3% O_2 (concentration limit). Compliance with this rule is achieved if either limitation is met. As stated in the Emission Calculation section, the potential-to-emit of particulate matter from the new cogeneration unit is 9.93 lbs/hr. This corresponds to a grain loading of 0.0021 grains/scf @ ~ 13.5% O_2 (equal to 0.0051 grains/scf @ 3% O_2) at full load operation (note: the HRSG – duct burner used in steam generation only contributes a fraction of the cogeneration unit PM mass emissions). The results of the 2008 source test of Cogeneration Unit Nos. 1 through 4 show that exhaust gases contain particulate matter with concentrations of 0.000342 to 0.000385 grains/dscf (as found) and mass emissions rates of 1.52 to 1.65 lbs/hr (Attachment #9). Compliance with the requirements of this rule is expected.

Reg IX – New Source Performance Standards

40 CFR 60 Subpart Db: This rule states standards of performance for industrial-commercial-institutional steam generating units. It applies to steam generating units which were constructed after June 19, 1984 and have a heat input capacity of greater than 100 MMBtu/hr. This regulation applies to the duct burners of Cogeneration Unit Nos. 1 through 4. Under this regulation the duct burners are limited to a NO_x emissions rate of 0.2 lbs/MMBtu. Permit condition H23.19 requires that the duct burners be compliance with the NO_x limitation under this regulation. The results of the 2008 source test of Cogeneration Unit Nos. 1 through 4 show that exhaust gases contain NO_x with an average mass emissions rate of 9.96 lbs/hr (Attachment #9). Using the average natural gas input of 11.425 lbs/sec (HHV = 22,834.6 Btu/lb) and refinery gas flow rate of 111 MSCFH (HHV = 998.95 Btu/scf), the average rate of NO_x emissions as a function of heat input is 0.00948 lbs/MMBtu. Of course, this represents the combined emissions from the gas turbine and duct burner. Continued compliance with this regulation is expected.

40 CFR 60 Subpart Da/Db/Dc: The refinery gas fired HRSG in the new cogeneration unit is not subject to this subpart because the CTG is subject to and will meet the requirements under 40 CFR 60 Subpart KKKK.

40 CFR 60 Subpart GG: This regulation applies to gas turbines which commenced construction, modification, or reconstruction after October 3, 1970 and have a heat input rating of at least 10 MMBtu/hr. Permit condition H23.18 requires that Cogeneration Unit Nos. 1 through 4 comply with the requirements of this regulation. The regulation imposes a limitation of NO_x concentration (@ 15% O_2) based on the manufacturer's rated heat rate of the gas turbine. The limit associated with this regulation for Cogeneration Unit Nos. 1 through 4 is 96 ppm NO_x (@ 15% O_2). Results of the 2008 source test of Cogeneration Unit Nos. 1 through 4 show that exhaust gases contain NO_x in the range of 2.23 to 2.45 ppm (@ 15% O_2) (Attachment #9). The regulation also imposes a 150 ppm SO_2 limitation on the gas turbines. The 2008 source test results indicate that SO_2 concentrations in the exhaust gas range from 0.00 to 0.04 ppm (@ 15% O_2). Continued compliance with the requirements of this regulation is expected for the existing cogeneration units. Since the new CTG/HRSG is subject to the requirements of 40 CFR 60 Subpart KKKK it is not subject to requirements under 40 CFR 60 Subpart GG.

40 CFR 60 Subpart J: This regulation, which is applicable to existing Cogeneration Unit Nos. 1 through 4, requires that fuel gas fired in combustion equipment contain H_2S with a

concentration of less than 0.1 grains/dscf (equal to 160 ppm). Permit conditions B61.4 limits the H_2S content of refinery fuel gas fired in these units to this limitation. Condition D90.4 requires continuous monitoring of fuel H_2S content to ensure compliance with this limit. Continued compliance with this regulation is expected. (Note: As permitted under condition D90.17 an Alternative Monitoring Plan (AMP) has been granted to the facility, detailing monitoring requirements when the existing cogeneration units combust butane.)

40 CFR 60 Subpart Ja: Both the new CTG and duct burner in the new HRSG are subject to standards under 40 CFR 60 Subpart Ja. This regulation applies to petroleum refineries which undergo construction, re-construction, or modification after May 14, 2007. Standards for SO_x for fuel gas combustion devices are: 1) the fuel gas combustion device shall not discharge into the atmosphere SO_x emissions of 20 ppm (dry basis, at 0% excess air), calculated hourly, over a 3-hour averaging period and 8 ppm (dry basis, at 0% excess air) calculated daily, over a 365 consecutive day averaging period; or 2) the fuel gas combusted shall not containing H_2S in excess of 162 ppm, calculated hourly, over a 3-hour averaging period and 60 ppm calculated daily, over a 365 successive day averaging period. For compliance with the fuel H_2S standard, the operator is required to install, operate, calibrate and maintain a continuous H_2S concentration (by volume) monitoring and recording device. Monitoring of H_2S at only one location is allowed, if monitoring at this location accurately indicates the H_2S concentration of fuel gas being burned. The refinery fuel gas combusted in the new CTG/HRSG will meet BACT standards for sulfur content, which are more stringent than the fuel gas H_2S standards stated under this regulation. Therefore, compliance with the requirements of this regulation is expected.

40 CFR 60 Subpart GGGa: This regulation applies to components at refineries from which fugitive VOC emissions may emanate. It applies to equipment which was constructed, re-constructed, or modified after November 7, 2006. The regulation applies to cogeneration unit equipment in refinery gas, light liquid, and heavy liquid service. It requires compliance with standards stated under 40 CFR 60 Subpart VVa. Components associated with the new cogeneration unit will be in compliance with these standards – as well as BACT standards and District Rule 1173 requirements.

40 CFR 60 Subpart QQQ: This regulation applies to equipment in wastewater service which was constructed, reconstructed, or modified after May 4, 1987. It states standards for individual drain systems, oil-water separators, and aggregate facilities. Standards for individual drain system include: that each drain be equipped with water seal control; each active drain system be inspected initially and monthly for effectiveness of the water seal control; periodic inspection of inactive drain seals to ensure adequate water level or (if equipped with tightly sealed cap or plug) that the cap or plug is in place and properly installed; and when necessary, addition of water to the water seal or repair of cap or plug within 24 hours of detection of a problem. Standards for junction boxes include: that the junction box have a cover with a tight seal; that vent pipes from junction boxes have diameter of no more than 4 inches and minimum length of 3 feet; initial and semi-annual

inspection of junction boxes to ensure that the cover is in place and has a tight seal around the edges; and initiation of repair of a junction box cover no later than 15 days after determination of a problem (broken seal or gap). Standards for sewer lines include: that sewer lines not be open to the atmosphere and not have gaps or cracks in joints, seals or emissions interfaces; initial and semiannual inspection of unburied sewer lines for cracks or gaps which could result in VOC emissions; and repair of leaks no more than 15 days after identification of a problem. Compliance with these standards for equipment in wastewater service, associated with the cogeneration unit, is expected.

40 CFR 60 Subpart KKKK: This regulation establishes emissions standards for stationary combustion turbines with a heat input of 10 MMBtu/hr or greater (based on the higher heating value of the fuel), which commenced construction, modification, or reconstruction after February 18, 2005. Since the new combustion turbine is subject to the requirements of this regulation, it is exempt from standards in 40 CFR 60 Subpart GG and the duct burner is not subject to the requirements under 40 CFR 60 Subpart Da/Db/Dc. This regulation states standards for NO_x and SO_x from combustion turbines. New combustion turbines, with a rated heat input greater than 850 MMBtu/hr, combusting 50% or greater of natural gas, are required to limit NO_x to 15 ppm @ 15% O_2 (or to 0.43 lbs/MWh). The emissions requirements for SO_x are to either limit SO_x emissions to 0.90 pounds per megawatt-hour (gross output), or to 0.060 lbs SO_x /MMBtu heat input, for each fuel combusted. The new cogeneration unit at Watson is expected to meet these emissions standards. NO_x emissions will be controlled to 2 ppm @ 15% O_2. Emissions of SO_x as a function of heat input are as follows: ~~0.0008~~ <u>0.0020</u> lbs/MMBtu for natural gas and 0.005 lbs/MMBtu for refinery gas.

The SO_x emissions factor for natural gas is calculated from a fuel sulfur content of ~~0.29~~ <u>0.75</u> grains H_2S/100 CF and the SO_x emissions factor for refinery gas is calculated from the fuel sulfur content of 30 ppm as H_2S. The calculations are shown below:

~~0.29~~ <u>0.75</u> grains H_2S/100 CF x lb/7000 grains x 64 lbs SO_2/34 lbs H_2S x cf/1028.05 Btu x 10^6 Btu/MMBtu

= ~~0.0008~~ <u>0.0020</u> lbs/MMBtu for natural gas

(30 ppm x 34 lb H_2S/lb-mole x 64 lbs SO_2/34 lbs H_2S / 10^6 ppm x 379 cf/lb-mole) x cf/998.95 Btu x 10^6 Btu/MMBtu

= 0.005 lbs/MMBtu for refinery gas

To demonstrate compliance with the NO_x limit, the facility is required to either perform a compliance test annually (or once every two years if the measured NO_x level is 75% or less of the appropriate limit) or the facility is required to install, calibrate, maintain and operate continuous emissions monitoring system or a continuous parameter monitoring system.

Each fuel flow meter, watt meter, and pressure and temperature measuring device is required to be installed, calibrated, maintained and operated according to manufacturer's instructions.

The facility is required to measure the total sulfur content of the fuel gas fired. However, monitoring of fuel sulfur content is not required if the fuel is demonstrated not cause emissions exceeding 0.060 lbs SO_2/MMBtu heat input. Monitoring of sulfur content of natural gas is not required if purchase or transportation contracts indicate the sulfur content is less than 20 grains per 100 cubic feet. Monitoring of fuel sulfur is not required if representative fuel sampling data show emissions will not exceed 0.060 lbs/MMBtu.

An initial performance test for NO_x is required to be performed at $\pm$ 25 percent of 100% of the peak load; three test runs each of 20 minute duration are required. Alternately, if a NO_x CEMS is installed, a performance test may be conducted to include a nine run RATA, with each run at least 21 minute duration, at $\pm$ 25 percent of 100% of the peak load. This performance test provides both the determination of compliance with the NO_x emissions limit and the reference method data for the CEMS RATA.

An initial performance test for sulfur is required, either through sampling and testing of fuel sulfur content, or measurement of SO_2 concentration in the stack gas and electrical and thermal output for determination of compliance with the lb/MWh limit, or measurement of SO_2 concentration in the stack gas and total heat input for determination of compliance with the lb/MMBtu limit.

The new combustion turbine will have CEMS for NO_x; therefore annual or bi-annual source testing for NO_x will not be required. The new combustion turbine is expected to be operated in compliance with the all applicable requirements of this regulation, including emissions limits, performance testing, and monitoring.

Rule 1134 This rule states limitations for oxides of nitrogen from existing stationary gas turbines (as of August 4, 1989) with capacity 0.3 MW or greater. Since the cogeneration units are subject to the requirements of the SCAQMD NO_x RECLAIM program, NO_x limitations stated in this rule do not apply.

Rule 1135 This rule states limitations for oxides of nitrogen from electric power generating equipment. Since the cogeneration units are subject to the requirements of the SCAQMD NO_x RECLAIM program, NO_x limitations stated in this rule do not apply.

Reg XIII/Rule 2005

This rule states requirements, including that new equipment meet Best Available Control Technology (BACT) standards, that emissions offsets be provided for an increase in non-attainment criteria pollutant emissions, and that air quality modeling be conducted to assess the impacts of the project on ambient air quality. Further, the addition of a fifth cogeneration unit is considered a Major Modification to an existing Major Source. The requirements of this regulation are addressed below.

<u>BACT</u>

For Major Sources, BACT is determined at the time of permitting and is the Lowest Achievable Emissions Rate (LAER) which has been achieved-in-practice. Based on recently issued permits (including Magnolia Power and Vernon City Power), the SCAQMD has determined BACT standards for natural gas fire cogeneration units, to be those stated below.

BACT for Natural Gas Fired Combined Cycle Gas Turbines

NO_x	CO	VOC	PM_{10}	SO_x	NH_3
2 ppmvd @ 15% O_2, 1-hour average	2 ppmvd @ 15% O_2, 1-hour average	2 ppmvd @ 15% O_2, 1-hour average	Natural Gas Fuel	Natural Gas Fuel with Fuel Sulfur Content of no more than 1 grain/100 scf (about 16 ppm)	5 ppmvd @ 15% O_2, 1-hour average

Criteria pollutants from the fifth cogeneration train will be controlled to very low levels, for this type of equipment. The SCAQMD has worked with the applicant and considers the standards stated below to be BACT for refinery gas/natural gas fired combined cycle gas turbines.

Control Levels for Fifth Cogeneration Unit

NO_x	CO	VOC	PM_{10}	SO_x	NH_3
2 ppmvd @ 15% O_2, 1-hour average	2 ppmvd @ 15% O_2, 3-hour average; 3 ppmvd @ 15% O_2, 1-hour average	2 ppmvd @ 15% O_2, 1-hour average	Use of Refinery Fuel Gas with the following limitations for Total Sulfur concentration, calculated as H_2S: 30 ppm (24-hour average) and 40 ppm (3-hour average) and use of Natural Gas regulated by the Public Utility Commission (PUC).	Use of Refinery Fuel Gas with the following limitations for Total Sulfur concentration, calculated as H_2S: 30 ppm (24-hour average) and 40 ppm (3-hour average) and use of Natural Gas regulated by the Public Utility Commission (PUC).	5 ppmvd @ 15% O_2, 1-hour average

A top-down BACT analysis of potential NO_x control technologies has been performed (see BP analysis in application folder entitled "Analysis of BACT/LAER Technologies for NO_x for Watson Expansion Project"). This analysis included identification of potential NO_x control technologies, evaluation of control technologies for technical feasibility, ranking of technically feasible technologies in order of control effectiveness, assuming the highest ranked technically feasible control technology is BACT (unless it can be shown to result in adverse environmental, energy, or economic impacts), and selection of BACT. The technologies evaluated include water or steam injection in the combustor, dry low NO_x combustor for the CTG with low NO_x burner in the HRSG, other combustion modifications, catalytic combustors, Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Non-Selective Catalytic Reduction (NSCR), and SCONOx. The analysis determined that the maximum degree of control, which results in the lowest NO_x emissions rate, is the use of dry low NO_x combustor in the CTG and low NO_x burner in the HRSG, in conjunction with either SCR or SCONOx technology. SCR has been demonstrated to be effective in numerous installations in the U.S. and levels of NO_x control equal to or slightly greater than 90% can be achieved (in conjunction with wet or dry combustion controls). However, the SCONOx process is not commercially demonstrated on larger, utility-scale turbines. Therefore, SCR was selected as BACT for this project.

Modeling

The applicant has determined air quality impacts of criteria pollutant emissions through air dispersion modeling. The purpose of the modeling is to ensure that the impact of the project does not result in exceedance of ambient air quality standards and in cases where the background concentration already exceeds the most stringent ambient air quality standard, to ensure that a significant change (increase) in air quality concentration will not occur. The US Environmental Protection Agency (USEPA) guideline model AERMOD (version 07026) was used as well as the latest versions of the AERMOD preprocessors to determine surface characteristics (AERSURFACE version 08009), to process meteorological data (AERMET version 06341), and to determine receptor slope factors (AERMAP version 06341). The modeling results of ground level pollutant concentrations, resulting from baseload operation of the new cogeneration unit, are shown in the table below. The applicant has also performed a similar analysis for emissions from startup/shutdown periods, commissioning activities, and modeling of cumulative emissions from the entire cogeneration facility. The analysis made use of background air quality data obtained from the North Long Beach, South Long Beach and Lynwood ambient air monitoring stations, during the period 2005 through 2007. As shown below, the impacts of the new cogeneration unit do not result in exceedance of ambient air quality standard (note: background annual average NO_2 concentrations already exceed the most stringent ambient air quality standard) and the project impacts do not exceed Allowable Significant Change, as designated by the SCAQMD.

Modeling Results for Baseload Operation of the New Cogeneration Unit

Pollutant	Averaging Time	Maximum Project Impact (ug/m3)	Background Concentration (ug/m3)	Total Impact (ug/m3)	Most Stringent Air Quality Standard (ug/m3)	Allowable Significant Change (ug/m3)
CO (ppm)	1-hour	1.930	9,600	9,601.93	23,000	1,100
	8-hour	1.370	7,315	7,316.37	10,000	500
NO_2 (ppm)	1-hour	1.585	264	265.59	339	20
	Annual	0.086	58.9	58.98	57	1
SO_2 (ppm)	1-hour	0.908	107	107.91	655	
	3-hour	0.720	86	86.72	1300	
	24-hour	0.227	28.6	28.83	105	
	Annual	0.062	7.0	7.062	80	
PM_{10} (ug/m3)	24-hour	0.363	131	131.36	50	2.5
	AGM	0.093	45.0	45.09	20	1

Note: maximum concentrations of PM_{10} due to turbine only (i.e. not from new cooling tower cells).

Since for the new cogeneration unit, peak 1-hour NO_2, 1-hour CO and 8-hour CO impacts occur during project commissioning, modeling results for emissions during commissioning are evaluated. As shown in the table below, the impacts of operation of the new cogeneration unit during commissioning, do not result in exceedance of the most stringent air quality standard.

Modeling Results for Commissioning

Pollutant	Averaging Time	Maximum Project Impact (ug/m3)	Background Concentration (ug/m3)	Total Impact (ug/m3)	Most Stringent Air Quality Standard (ug/m3)	Allowable Significant Change (ug/m3)
CO (ppm)	1-hour	34.89	9,600	9,634.89	23,000	1,100
	8-hour	26.01	7,315	7,341.01	10,000	500
NO_2 (ppm)	1-hour	28.87	264	292.87	339	20

Attachment #6 is a memorandum from Naveen Berry - Planning and Rules Manager to Jay Chen – Senior Air Quality Engineering Manager, indicating that the modeling work performed by the applicant has been reviewed and determined to be acceptable by SCAQMD staff.

A new Federal NO_2 1-hour ambient air standard of 100 ppb (188 µg/m3) was published in the Federal Register on February 9, 2010 with an effective date of April 12, 2010. The South Coast Air Basin is not designated as non-attainment for the new standard. As a result, this new Federal NO_2 standard is not applicable to the Watson Cogeneration Project. The CEC has recently made such a determination as shown in the commission decision for CPV Sentinel Energy Project dated December 2010 (Docket No. 07-AFC-3).

Emissions Offsets

PM_{10} BP seeks to mitigate PM_{10} emissions from the new cogeneration unit through adoption of an emissions limit for all five cogeneration units, which is equal to the current limit for the existing four units, minus 1 lb PM_{10}/day. The CEC permit limits PM emissions from the four existing cogeneration units to 1244 lbs/day; hence the new limit will be 1243 lbs PM_{10}/day for all five cogeneration units. This is granted since recent source testing indicates that the actual PM_{10} emissions from the four existing cogeneration units are 436 lbs/day (year 2007 test) and 153 lbs/day (year 2008 test). Thus, the potential emissions of 238 lbs PM_{10}/day from the fifth cogeneration unit should not result in exceedance of the 1243 lbs/day limit. Proposed condition A63.X2 will require the facility to calculate PM_{10} emissions from all five cogeneration units, based on emissions factors for natural gas, butane and refinery gas firing (note: cogeneration units 1 through 4 are permitted to fire butane, while the fifth cogeneration unit is not permitted to fire butane). For this project, an exemption from emissions offsets under District Rule 1304, due to Concurrent Facility Modification, is claimed for PM_{10} emissions.

ROG ERCs will be provided, either through current holdings or through purchase on the open market. As shown in the Emission Calculation section of this report, the increase in ROG emissions due to the fifth cogeneration unit is 156 lbs/day (30-day average). Using an offset ratio of 1.2, ERCs accounting for 187 lbs ROG/day are required for permitting of the project. The applicant must hold these ERCs in their account prior to issuance of Permits to Construct. The facility currently holds ERCs for 61 lbs ROG/day (ERC Certificate No. AQ007588 - 4 lbs ROG/day; ERC Certificate No. AQ008748 - 7 lbs ROG/day; ERC Certificate No. AQ010814 - 50 lbs ROG/day). The facility is working with a broker to identify and to purchase the required ERCs, equal to 126 lbs ROG/day.

NO_x NO_x RTCs will be allocated either through existing holdings or through purchase.

SO_x SO_x RTCs will be allocated either through existing holdings or through purchase.

CO Offsets will not be required since the District is designated as “attainment” with ambient CO standards.

Per 1303(b)(3), a facility in zone 1 may only obtain Emissions Reduction Credits originating in zone 1, to demonstrate to the Executive Officer a net air quality benefit in the area impacted by emissions from the subject facility. BP West Coast Products LLC is in zone 1 and thus must obtain ERCs from the same zone. The SCAQMD will ensure that ERCs for the increase in VOC emissions are obtained from facilities in zone 1.

Per 1303(b)(4), a facility must be in compliance with all applicable rules and regulations of the SCAQMD. BP West Coast Products LLC is currently in compliance with all SCAQMD rules. Under Hearing Board Case No. 5357-36, BP was granted a variance from the flare gas monitoring requirements under Rule 1118. This is addressed in the BP’s Title V permit, in condition I.1.1. BP has notified the Hearing Board, in a letter dated January 20, 2010, that final compliance with rule requirements has been achieved for all flares.

An Alternative Analysis, as described under 1303(b)(5)(A), is complied with through the CEC licensing procedure. Under this procedure, project alternatives are analyzed.

Per 1303(b)(5)(B), for a major modification at an existing major pollutant facility, the facility must demonstrate that all major sources owned or operated under common control are in compliance or on a schedule for compliance with limitations and standards of the Clean Air Act. BP West Coast Products LLC submitted to the SCAQMD, on ~~August 25, 2006~~ September 20, 2010, a statement that its facilities in California are in compliance or on schedule for compliance with applicable emissions limits and standards of the Clean Air Act (Attachment #7).

Modeling of plume visibility, as described under 1303(b)(5)(C) is not required because the project does not result in an emissions increase of 15 tons PM_{10}/year or 40 tons NO_x/year. Further, the site location is not within the prescribed distances (28 to 32 km) of a Federal Class I Area (note: minimum distance of the Watson Cogeneration project to any of the listed Federal Class I Areas is 53 km).

Under 2005(b)(2)(A) the applicant is required to demonstrate that sufficient RTCs are held to offset total emissions from the new facility from the first year of operation, at a ratio of 1:1. Condition I296.X1 addresses this requirement, stating that the equipment may not be operated unless the operator demonstrates that sufficient RTCs are held to cover the increase from the first compliance year and subsequent compliance years (at the commencement of each compliance year).

Rule 1401 This rule has requirements including that the Maximum Individual Cancer Risk (MICR) associated with the project be under $1x10^{-6}$ if T-BACT is not used, or $10x10^{-6}$ if T-BACT is applied, that the hazard indices be less than 1.0 and the cancer burden be under 0.5. A Health Risk Assessment (HRA) was conducted for the new CTG/HRSG using AERMOD and Hot Spots Analysis and Reporting Program (HARP, version 1.4a). For the new CTG/HRSG the MICR was determined to be less than ten in a million. The chronic and acute hazard indices were determined to be less than 1.0. The HRA results, which were reviewed and approved by the SCAQMD Modeling group (See Attachment #6 for memorandum from Naveen Berry to Jay Chen, dated July 22, 2009, regarding HRA review), are presented below:

Risk Category	Project Values	Applicable Significance Threshold
Cancer Risk, Residential Receptor	6.3×10^{-6}	10.0×10^{-6} with T-BACT
Cancer Risk, Worker Receptor	1.2×10^{-6}	10.0×10^{-6} with T-BACT
Chronic Hazard Index, Maximum	0.02	1.0
Acute Hazard Index, Maximum	0.008	1.0
Cancer Burden	0.028	0.5

The new CTG/HRSG, equipped with an oxidation catalyst to oxidizer hydrocarbons (including toxic air contaminants) as well as carbon monoxide, meets T-BACT standard for this application. Based on these results, the project is determined to be in compliance with Rule 1401.

Reg XVII This rule pertains to emissions of pollutants for which attainment with ambient air standards has been achieved in the South Coast Air Basin (NO_2, SO_2, CO and lead). The project meets BACT requirement. Further, the proposed modification to the Watson Cogeneration Plant does not result in a Significant Emissions Increase (as defined in Rule 1702) at a major stationary source, nor is the project located within 10 km of a Federal Class I Area. Therefore, while PSD - Regulation XVII applies to this equipment, a PSD analysis as outlined in Rule 1703 is not required for this project. Annual emissions associated with project are compared to Significant Emissions Increase under Reg XVII, below:

	Project Annual Emissions Tons/Year	Reg XVII Significant Emissions Increase Tons/Year
NO_x	39.9	40
CO	~~33.1~~ 37.8	100
VOC**	27.6	40
SO_x	19.9	40
PM_{10}	43.5	15

Notes:
** Includes VOC emissions from fugitive components.
~~PM10 is not a pollutant for which attainment of ambient air quality standards has been achieved.~~
PM_{10} is currently designated as a non-attainment air contaminant in the South Coast Air Basin.
VOC is currently designated as a non-attainment air contaminant in the South Coast Air Basin, since VOC and NO_x are precursors to ozone formation.
The South Coast Air Basin is currently designated as being in attainment with ambient air quality standards for CO, NO_2, SO_2, and lead.

Rules 2011/2012

This facility is subject to Reg. XX, RECLAIM with respect to NO_x and SO_x emissions. For Cogeneration Unit Nos. 1 through 4 there is no~~t~~ increase in emissions of these pollutants. Therefore, there are no additional requirements under these rules for these units.

The new CTG/HRSG is classified as a Major NO_x Source/Major SO_x Source under these rules, requiring the installation of CEMS, totalizing fuel meter, and equipment to transmit daily NO_x/SO_x emissions to the SCAQMD central station. A certified NO_x CEMS must be used to measure and record NO_x emissions, to ensure continued compliance with the NO_x BACT limit and to provide daily mass emissions for submittal to the SCAQMD. The CEMS must be installed within 90 days of startup. Since the new CTG/HRSG is fired with refinery gas, it is subject to SO_x RECLAIM as a Major SO_x Source. As such, the new CTG/HRSG is required to be equipped with a SO_x CEMS or a continuous fuel sulfur analyzer

The interim NO_x emissions factor of 44 lbs/MMCF, for reporting of NO_x prior to certification of the NO_x CEMS, was calculated as the uncontrolled emissions from Case E-3 (Note: Case E-3 is the worst case for pollutant emissions – maximum CTG/HRSG firing, air temperature of 36°F, and 36% Relative Humidity) as follows:

NO_x (lbs/MMCF) = 64.56 lbs NO_x/hr / (1,363.5 MMBtu/hr $_{LHV}$ / 920.30 BTU/CF $_{LHV}$)

44 lbs NO_x/MMCF

The interim SO_x emissions factors of ~~0.80~~ 2.02 lbs/MMCF (natural gas) and 5.07 lbs/MMCF (refinery gas), for reporting of SO_x prior to certification of the SO_x CEMS, are calculated from expected fuel sulfur content as follows:

SO_x (lbs/MMCF) = ~~0.29~~ 0.75 grains H_2S/100 CF x lb/7000 grains x 64 lbs SO_2/34 lbs H_2S

x 10^6 CF/MMCF

~~0.80~~ 2.02 lbs/MMCF for natural gas

SO_x (lbs/MMCF) = 30 ppm x 34 lb H_2S/lb-mole / (10^6 ppm x 379 cf/lb-mole) x

x 64 lbs SO_2/34 lbs H_2S x 10^6 CF/MMCF

= 5.07 lbs/MMCF for refinery gas

Reg XXX The facility is subject to Reg XXX and a Title V permit was issued on September 1, 2009. The permitting of the new CTG/HRSG is a Significant Permit Revision of the Title V permit issued to BP West Coast Products LLC. BP has submitted A/Ns 496922 and 496924 to address this permit revision. As a Significant Permit Revision, the applications are subject to a 30 day public notice and a 45 day EPA review and comment period.

Rule 3006 addresses public notice requirements. It requires that a public notice be published in a newspaper serving the county where the source is located, or that a notice be sent by mail to those who request in writing to be on a list, and any other means as determined by the Executive Officer to ensure adequate notice to the affected public. This rule requires that the notice contain the following:

i) The identity and location of the affected facility;
ii) The name and mailing address of the facility's contact person;
iii) The identity and address of the South Coast Air Quality Management District as the permitting authority processing the permit;
iv) The activity or activities involved in the permit action;

v) The emissions change involved in any permit revision;
vi) The name, address, and telephone number of a person whom interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer which are relevant to the permit decision;
vii) A brief description of the public comment procedure; and,
viii) The time and place of any proposed permit hearing which may be held, or a statement of the procedure to request a proposed permit hearing if one has not already been requested.

~~The SCAQMD plans to meet all public notice and EPA review and comment requirements for this project. Compliance with this regulation is expected.~~

The public notice for this project, which included all of the elements described above, was published in two newspapers serving the area surrounding the facility, La Opinion and Daily News Los Angeles, on October 15, 2010. The public notice was also distributed to members of the public who are on an SCAQMD list as being interested in reviewing significant changes to the Title V permit issued to BP West Coast Products LLC, as well as the CEC, the State of California Air Resources Board (CARB), the City of Carson, the County of Los Angeles, the Southern California Association of Governments (SCAG), U.S. Department of Agriculture – Forrest Service, U.S. Department of the Interior – National Park Service, as well as organizations identified as Intervenors by the CEC. The SCAQMD did not receive any comments from any other governmental agency or any member of the public regarding the proposed permit.

On October 12, 2010 the SCAQMD forwarded to the EPA, for review and comment, the proposed permit, the District's evaluation of the project, the public notice, and a cover letter. The 45 day EPA review and comment period has concluded. The SCAQMD has not received any comments from the EPA regarding the proposed permit.

Thus, compliance with the EPA review and public notice requirements of this regulation has been achieved.

Reg XXXI The project is subject to Title IV of the Clean Air Act Amendments of 1990, since the turbine is a new unit serving a generator with rating greater than 25 MW. The new CTG/HRSG is subject to the Acid Rain program and allowance system, stated under 40 CFR 72. The program uses "SO_2 allowances" which are similar in concept to RECLAIM Trading Credits. Requirements include: submittal of Acid Rain permit application (including compliance plan), compliance with the monitoring requirements under part 75, holding allowances for total annual emissions of sulfur dioxide, complying with the Acid Rain emissions limitations for NO_x, submittal of a proposed offset plan for a source with excess emissions, etc. Mass emissions of SO_2 are to be recorded every hour. NO_x and O_2 must be monitored with a CEMS in accordance with the specifications under Part 75. Part 75 requires that the CEMS be installed and certified within 90 days of startup. Under this program, NO_x and SO_x emissions are reported directly to the US EPA. The facility will submit applications for inclusion in the Acid Rain program. Compliance with this regulation is expected.

40 CFR Part 64 – Compliance Assurance Monitoring

The CAM regulation applies to emissions units at major stationary sources required to obtain a Title V permit, which use control equipment to achieve a specified emissions limit and which have emissions that are at least 100% of the major source threshold on a pre-control basis. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with emissions limits. The emissions from the new CTG/HRSG are greater than the major source thresholds for NO_x, CO, and VOC and the new CTG/HRSG will be subject to an emission limitation for each pollutant.

NO_x

- Emission Limit – NO_x is subject to a 2.0 ppm (1-hour average) BACT limit
- Control Equipment – NO_x is controlled with an SCR
- Requirement – As a NO_x Major Source under RECLAIM, the new CTG/HRSG is required to have a CEMS under Rule 2012. Use of a continuous monitor to show compliance with an emissions limit is exempt from CAM under 64.2(b)(vi).

CO

- Emission Limit – CO is subject to the following BACT limits: 3.0 ppm (1-hour average), 2.0 ppm (3-hour average)
- Control Equipment – CO is controlled with an oxidation catalyst
- Requirement – The new CTG/HRSG will be required to have a CEMS under Rule 1303-BACT. Use of a continuous monitor to show compliance with an emissions limit is exempt from CAM under 64.2(b)(vi).

VOC

- Emission Limit – VOC is subject to a 2.0 ppm (1-hour average) BACT limit.
- Control Equipment – VOC is controlled with an oxidation catalyst
- Requirement – The oxidation catalyst is ineffective under low temperatures. Condition D12.X2 requires that the temperature at the inlet of the SCR/Oxidation Catalyst be continuously monitored and recorded to ensure proper operation of the SCR/oxidation catalyst.
- The CO CEMS is believed to provide an adequate means of determination of compliance with the VOC emissions limit. In development of the Maximum Achievable Control Technology (MACT) standard for FCCUs (under 40 CFR 63 Subpart UUU), EPA determined that CO was a good surrogate for organic HAP emissions from FCCUs, since efficient combustion in the regenerator is expected to yield low CO and organic HAP emissions. For the subject CTG/HRSG, CO and VOC emissions are a function of combustion efficiency and control by the CO catalyst. CO emissions are the best

indicator of combustion efficiency and effectiveness of the CO catalyst. The CO CEMS data will be supplemented with source testing for VOC every three years.

For the reasons stated above, a CAM Plan will not be required for the new CTG/HRSG.

40 CFR 63, Subpart CC

The National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Petroleum Refineries states standards for equipment at plants which are major sources of Hazardous Air Pollutants (HAP)s and which contain or contact one or more of the HAPs listed in Table 1 of the subpart. Equipment for which standards are stated include miscellaneous process vents, storage vessels, wastewater streams and treatment operations, equipment leaks, gasoline loading racks, marine vessel loading operations, and storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station.

Fugitive components associated with the existing cogeneration units and the new CTG/HRSG are not subject to this regulation. The basis of the exemption is that fugitive components either do not contain or contact HAPs listed in Table 1 of the subpart, or are associated with the refinery fuel gas system. Under this regulation, no testing, monitoring, recordkeeping, or reporting is required for fuel gas systems or equipment venting to fuel gas systems.

40 CFR 63, Subpart YYYY

This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility which emits 10 tons per year or more of a single HAP, or 25 tons per year of a combination of HAPs, based on the potential-to-emit. The BP Carson refinery is a major source of HAPs. The National Emissions Standards for Hazardous Air Pollutants (NESHAP)s require the application of Maximum Achievable Control Technology (MACT) to any new or reconstructed source of HAPs to minimize those emissions. Under this regulation, Cogeneration Unit Nos. 1 through 4 are designated "Existing Stationary Combustion Turbines," since they were constructed prior to January 14, 2003. Under this regulation, there are no emissions or operating limits for existing gas turbines.

Specifically, the regulation applies to the combustion turbine portion of any stationary cogeneration cycle combustion system. As stated in section 63.6095, gas fired combustion turbines (lean premix gas fired stationary combustion turbines or diffusion flame gas fired stationary combustion turbines) are required to meet initial notification requirements, but are not required to meet any other requirements of this regulation until the US EPA takes final action to require compliance and publishes a document in the Federal Register. Notification within 120 days of becoming subject to this subpart (i.e. within 120 days of start-up of a new lean pre-mix gas fired stationary combustion turbine) is required. The notification must include a statement that the combustion turbine has no additional emissions limitations requirements. Compliance with the requirements of this regulation, for the new combustion turbine, is expected.

40 CFR 63, Subpart DDDDD

This regulation establishes emissions limits and work practice standards for HAPs emitted from industrial, commercial, institutional boilers and process heaters located at major sources of HAPs. It was promulgated on September 13, 2004. However, on June 19, 2007 the United States Court of Appeals for the District of Columbia Circuit vacated and remanded it. A new rule was proposed on June 4, 2010; the public comment period for the proposed rule ends on August 23, 2010.

Under the proposed regulation a boiler is defined as an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. A HRSG equipped with a duct burner, which is designed to supply 50% or more of the total rated capacity of the HRSG, is classified as a boiler. The fifth train will be equipped with a duct burner with a capacity of 510 MMBtu/hr. This represents approximately 50% of the capacity of the boiler, designed to produce 624,000 lbs/hr of steam @ 924◦F. Under the proposed regulation, the HRSG will likely be classified as new boiler (note: the proposed regulation does not include a date which specifies the construction date for new boilers). The proposed regulation lists eleven subcategories of boilers and process heaters; the HRSG would be classified under category nine – units designed to burn natural gas/refinery gas. The proposed regulation does not state any emissions limits for this category of equipment. However, new boilers and process heaters in natural gas/refinery gas service, with a heat input exceeding 10 MMBtu/hr, are required to perform an annual tune-up. The tune-up includes the following: inspection of the burner and cleaning/replacement of components; inspection and optimization of the flame pattern; inspection and correction of the air-to-fuel control system; minimization of total CO emissions; measurement of CO concentration before and after adjustments are made; maintaining on site an annual report containing: 1) CO concentration measurements made before and after adjustments, 2) description of corrective actions taken as part of combustion adjustments, and 3) type and quantity of fuel used prior to annual adjustment. The HRSG is not subject to any operating limits, performance testing, or other requirements stated in Tables 4 through 8 of the proposed regulation. Thus, compliance with the applicable requirements of this regulation is expected.

RECOMMENDATIONS

Since the proposed equipment is found to be compliance with SCAQMD rules, issuance of Permits to Construct which are subject to the following conditions, is recommended:

S2.X1 The operator shall limit emissions from this system as follows:

CONTAMINANT	EMISSIONS LIMIT
NOx	Less than 39.9 TONS IN ANY 12-MONTH PERIOD

Compliance with this limitation shall be determined monthly and shall be based on the total emissions over the previous 12 month period.

[RULE 1703 PSD Analysis, 10-7-1988]

[Systems subject to this condition: Process 17, System 9]

S7.X1 The following condition shall apply to all refinery operation and related devices from this system:

The operator shall upon completion of construction, operate and maintain this equipment in accordance with all mitigation measures stipulated in the Final California Energy Commission decision for the 09-AFC-1 project.

The operator shall maintain records, in a manner approved by the District, to demonstrate compliance with the applicable measures stipulated in the "Final California Energy Commission decision for the 09-AFC-1 project " document.

[CA PRC CEQA, 11-23-1970]

[Systems subject to this condition: Process 17, System 9, 10]

S7.X2 The following condition shall apply to all refinery operation and related devices from this system:

The operator shall submit to the District for review and approval, final drawings and specifications of the selective catalytic reduction system and carbon monoxide oxidation catalytic reactor to be installed, at least 30 days prior to construction. This equipment shall meet performance specifications stated in the application for permit to construct for the APC system serving Cogeneration Unit No. 5.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Systems subject to this condition: Process 17, System 10]

~~S31.10 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 454566, 454567, 454568, 458598, 458600, 458610, 459257, 459284, 459286 & 496922:~~

~~The operator shall provide to the District, no later than 90 days after initial startup, a recalculation of the fugitive emissions based on actual components installed and removed from service. The valves and flanges shall be categorized by size and service. The operator shall submit a listing of all new non-bellows seal valves which shall be categorized by tag no., size, type, operating temperature, operating pressure, body material, application, and reasons why bellows seal valves were not used.~~

~~All new valves in VOC service, except those specifically exempted by Rule 1173 and those in heavy liquid service as defined in Rule 1173, shall be bellows seal valves, except as approved by the~~

~~District, in the following applications: heavy liquid service, control valve, instrument piping/tubing, applications requiring torsional valve stem motion, applications where valve failure could pose safety hazard (e.g., drain valves with valve stems in horizontal position), retrofits/special applications with space limitations, and valves not commercially available.~~

~~All new valves and major components in VOC service as defined by Rule 1173, except those specifically exempted by Rule 1173 and those in heavy liquid service as defined in Rule 1173, shall be distinctly identified from other components through their tag numbers (e.g., numbers ending in the letter "N"), and shall be noted in the records.~~

~~All new components in VOC service as defined in Rule 1173, except valves and flanges, shall be inspected quarterly using EPA reference Method 21. All new valves and flanges in VOC service, except those specifically exempted by Rule 1173, shall be inspected monthly using EPA Method 21.~~

~~If 98.0 percent or greater of the new (non-bellows seal) valves and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv for two consecutive months, then the operator may change to a quarterly inspection program with the approval of the District.~~

~~The operator shall revert from quarterly to monthly inspection program if less than 98.0 percent of the new (non-bellows seal) valves and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv.~~

~~All new components in VOC service with a leak greater than 500 ppmv but less than 1,000 ppmv, as methane, measured above background using EPA Method 21 shall be repaired within 14 days of detection. Components shall be defined as any valve, fitting, pump, compressor, pressure relief valve, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.~~

~~The operator shall keep records of the monthly inspection (quarterly where applicable), subsequent repair, and reinspection, in a manner approved by the District. Records shall be kept and maintained for at least five years, and shall be made available to the Executive Officer or his authorized representative upon request.~~

~~All open-ended valves shall be equipped with cap, blind flange, plug, or a second valve.~~

~~All pressure relief valves shall be connected to a closed vent system or equipped with a rupture disc and telltale indicator.~~

~~All pumps shall utilize double seals and be connected to a closed vent system.~~

~~All compressors to have a seal system with a higher pressure barrier fluid.~~

~~**[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996]**~~

~~[Systems subject to this condition: Process 17, System 9]~~

S31.X The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 496922:

The operator shall provide to the District, no later than 90 days after initial startup, a recalculation of the fugitive emissions based on actual components installed and removed from service. The valves and flanges shall be categorized by size and service. The operator shall submit a listing of all new non-bellows seal valves which shall be categorized by tag no., size, type, operating temperature, operating pressure, body material, application, and reasons why bellows seal valves were not used.

All new valves in VOC service, except those specifically exempted by Rule 1173 and those in heavy liquid service as defined in Rule 1173, shall be bellows seal valves, except as approved by the District, in the following applications: heavy liquid service, control valve, instrument piping/tubing, applications requiring torsional valve stem motion, applications where valve failure could pose safety hazard (e.g., drain valves with valve stems in horizontal position), retrofits/special applications with space limitations, and valves not commercially available.

All new valves and major components in VOC service as defined by Rule 1173, except those specifically exempted by Rule 1173 and those in heavy liquid service as defined in Rule 1173, shall be distinctly identified from other components through their tag numbers (e.g., numbers ending in the letter "N"), and shall be noted in the records.

All new components in VOC service as defined in Rule 1173, except valves and flanges, shall be inspected quarterly using EPA reference Method 21. All new valves and flanges in VOC service, except those specifically exempted by Rule 1173, shall be inspected monthly using EPA Method 21.

If 98.0 percent or greater of the new (non-bellows seal) valves and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv for two consecutive months, then the operator may change to a quarterly inspection program with the approval of the District.

The operator shall revert from quarterly to monthly inspection program if less than 98.0 percent of the new (non-bellows seal) valves and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv.

All new components in VOC service with a leak greater than 500 ppmv but less than 1,000 ppmv, as methane, measured above background using EPA Method 21 shall be repaired within 14 days of detection. Components shall be defined as any valve, fitting, pump, compressor, pressure relief valve, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

The operator shall keep records of the monthly inspection (quarterly where applicable), subsequent repair, and reinspection, in a manner approved by the District. Records shall be kept and maintained for at least five years, and shall be made available to the Executive Officer or his authorized representative upon request.

All process drains shall be equipped with water seal, or a closed vent system and control device complying with the requirements of 40CFR60 Subpart QQQ Section 60.692-5.

All open-ended valves shall be equipped with cap, blind flange, plug, or a second valve.

All pressure relief valves shall be connected to a closed vent system or equipped with a rupture disc and telltale indicator.

All pumps shall utilize double seals and be connected to a closed vent system.

All compressors to have a seal system with a higher pressure barrier fluid.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Systems subject to this condition: Process 17, System 9]

A63.12 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
ROG	Less than or equal to 108 LBS PER DAY
NOX	Less than or equal to 2156 LBS PER DAY
SOX	Less than or equal to 59 LBS PER DAY
CO	Less than or equal to 82 LBS PER DAY
PM	Less than or equal to 186 LBS PER DAY

The operator shall calculate the emissions, as the total emissions from the waste heat boiler exhaust of a cogeneration unit during the 24 hours of operation following firing.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

A63.X1 The operator shall limit emissions from this equipment as follows

CONTAMINANT	EMISSIONS LIMIT
VOC	Less than or equal to 3,095 LBS IN ANY ONE MONTH

For the purposes of this condition, the limit(s) shall be based on the total combined emissions from equipment DX1 (Gas turbine) and DX2 (Duct Burner). The operator shall calculate emissions by using monthly fuel use data and an emissions factor 2.64 lbs VOC/MMscf for Natural Gas. For Refinery Gas, the following formula should be used to calculate emissions factors, in units of lbs VOC/MMscf: 2.94E-7 x F_d-Factor x GCV_v; where the F_d-Factor is the ratio of the volume of products of combustion to the fuel heat content, in units of dscf/MMBtu, and GCV_v is gross fuel calorific value, in units of Btu/scf. Monthly averages of F_d-Factor and GCV_v for Refinery Gas shall be used in this calculation.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

A63.X2 The operator shall limit emissions from this equipment as follows

CONTAMINANT	EMISSIONS LIMIT
PM10	Less than or equal to 1,243 lbs in any one day

For the purposes of this condition, the limit(s) shall be based on the total combined emissions from Cogeneration Units 1 (D1226 and D1227 in Process 17, System 1), 2 (D1233 and D1234 in Process 17, System 2), 3 (D1236 and D1237 in Process 17, System 3), 4 (D1239 and D1240 in Process 17, System 4), and 5 (DX1 and DX2 in Process 17, System 9).

The operator shall initially calculate the daily PM10 emissions using daily fuel use data for each combustion unit (D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240, DX1 and DX2), the higher heating value of the fuel burned in each combustion unit, and the following emissions factors: 0.00393 lbs PM10 / MMBTU for Natural Gas or Butane and 0.00402 lbs PM10 / MMBTU for Refinery Gas.

The PM10 emission factor for Cogeneration Units 1, 2, 3, 4, and 5 shall be revised annually based on results of individual PM10 source tests performed as specified in permit conditions D28.1 and D29X4. The PM10 emission factor shall be calculated as the average emission rate in lb/MMBtu for all valid source test runs during each individual source test.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2, D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

A99.1 The 8 PPM NOX emission limit(s) shall not apply when this equipment is operating during startup and shutdown modes.

[**RULE 2005, 5-6-2005**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

A99.2 The 2.5 PPM CO emission limit(s) shall not apply when the associated gas turbine is operating at less than 85 percent of the rated capacity. This condition refers to CO emission limit.

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

A99.3 The 2.5 PPM CO emission limit(s) shall not apply when the equipment is operating at startup and shutdown modes.

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

A99.X1 The 5 ppm NH3 limit(s) shall not apply during commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 550 hours. The time for cold startup shall not exceed 3 hours for each startup. The time for warm startup shall not exceed 1 hour. The time for shutdown shall not exceed 1 hour. The turbine shall be limited to 4 cold startups per year, ~~12~~ 24 warm startups per year, and ~~16~~ 29 shutdowns per year. Written records of commissioning, cold startups, warm startups and shutdowns shall be maintained and made available upon request from the Executive Officer.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: CX1]

A99.X2 The 2 PPM NOX emission limit(s) shall not apply during commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 550 hours. The time for cold startup shall not exceed 3 hours for each startup. The time for warm startup shall not exceed 1 hour. The time for shutdown shall not exceed 1 hour. The turbine shall be limited to 4 cold startups per year, ~~12~~ 24 warm startups per year, and ~~16~~ 29 shutdowns per year. Written records of commissioning, cold startups, warm startups and shutdowns shall be maintained and made available upon request from the Executive Officer.

[RULE 2005, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

A99.X3 The 2 PPM CO emission limit(s) shall not apply during commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 550 hours. The time for cold startup shall not exceed 3 hours for each startup. The time for warm startup shall not exceed 1 hour. The time for shutdown shall not exceed 1 hour. The turbine shall be limited to 4 cold startups per year, ~~12~~ 24 warm startups per year, and ~~16~~ 29 shutdowns per year. Written records of commissioning, cold startups, warm startups and shutdowns shall be maintained and made available upon request from the Executive Officer.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

A99.X4 The 3 PPM CO emission limit(s) shall not apply during commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 550 hours. The time for cold startup shall not exceed 3 hours for each startup. The time for warm startup shall not exceed 1 hour. The time for shutdown shall not exceed 1 hour. The turbine shall be limited to 4 cold startups per year, ~~12~~ 24 warm startups per year, and ~~16~~ 29 shutdowns per year. Written records of commissioning, cold startups, warm startups and shutdowns shall be maintained and made available upon request from the Executive Officer.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

A99.X5 The 44 LBS/MMCF NOX emission limit(s) shall only apply during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial startup date.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

A99.X6 The 0.80 LBS/MMCF SOX emission limit(s) shall only apply during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial startup date.

[RULE 2011, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

A99.X7 The 5.07 LBS/MMCF SOX emission limit(s) shall only apply during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial startup date.

[RULE 2011, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

A195.X1 The 5 PPM NH3 emission limit(s) is averaged over 60 minutes at 15 percent O2, dry. The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH3(ppmv) = [a-(b*c)/1E6]*1E6/b

where,
a= NH3 injection rate (lb/hr)/17(lb/lbmole)
b= dry exhaust gas flow rate(lb/hr)/29(lb/lbmole)
c= change in measured NOx across the SCR (ppmvd at 15 percent O2).

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppm accurate to within + /- 5 percent calibrated at least every 12 months.
The NOx analyzer shall be installed and operated within 90 days of initial start-up.

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

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

[**RULE 1303(a)(1)-BACT, 5-10-1996**; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: CX1]

A248.1 The 8 PPM NOX emission limit is dry, corrected to 15 percent oxygen.

[**RULE 2005, 5-6-2005**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

A248.2 The 2 PPM SOX emission limit is dry, corrected to 15 percent oxygen.

[**RULE 2005, 5-6-2005**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

A248.3 The 2.5 PPM CO emission limit is dry, corrected to 15 percent oxygen.

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

A248.4 The 4.5 PPM CO emission limit is dry, corrected to 15 percent oxygen.

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

~~A248.X1~~ A195.X2 The 2 PPMV NOX emission limit(s) ~~are~~ is averaged over 60 minutes at 15 percent oxygen, dry.

[RULE 2005, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

~~A248.X2~~ A195.X3 The 2 PPMV CO emission limit(s) ~~are~~ is averaged over 180 minutes at 15 percent oxygen, dry.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: DX1, DX2]

~~A248.X3~~ A195.X4 The 3 PPMV CO emission limit(s) ~~are~~ is averaged over 60 minutes at 15 percent oxygen, dry.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

~~A248.X4~~ A195.X5 The 2 PPMV VOC emission limit(s) ~~are~~ is averaged over 60 minutes at 15 percent oxygen, dry.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

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

[**RULE 475, 10-8-1976**; RULE 475, 8-7-1978]

[Devices subject to this condition: DX1, D1226, D1233, D1236, D1239]

A327.2 For the purpose of determining compliance with District Rule 476, combustion contaminant emissions may exceed the concentration limit or mass emission limit listed, but not both limits at the same time.

[**RULE 476, 10-8-1976**]

[Devices subject to this condition: DX2, D1227, D1234, D1237, D1240]

A433.X1 The operator shall comply at all times with the 2.0 ppm 1 hour BACT limit for NOx, except as defined in condition A99.X2, and for the following operating scenarios:

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Cold Start	175.0	This is a startup which occurs more than 48 hours after a gas turbine shutdown. NOx emissions shall not exceed 211.24 lbs per cold start-up. Written records of cold start-ups shall be maintained and made available upon request from the Executive Officer.
Warm Start	21.32	This is a startup which occurs within 48 hours of a gas turbine shutdown. NOx emissions shall not exceed 21.32 lbs per warm start-up. Written records of warm start-ups shall be maintained and made available upon request from the Executive Officer.

Shutdown	12.85	This is the period beginning immediately prior to the termination of fuel flow to the gas turbine, until complete termination of fuel flow. NOx emissions shall not exceed 12.85 lbs per shutdown. Written records of shutdowns shall be maintained and made available upon request from the Executive Officer.

[RULE 2005, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

B61.1 The operator shall only use refinery gas containing the following specified compounds:

Compound	ppm by volume
Total Sulfur less than	100

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

B61.2 The operator shall only use butane containing the following specified compounds:

Compound	ppm by volume
Total Sulfur less than	50

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

B61.3 The operator shall only use natural gas containing the following specified compounds:

Compound	ppm by volume
Total Sulfur less than	5

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

B61.4 The operator shall not use fuel gas, except uncombined natural gas which is not regulated by this condition, containing the following specified compounds:

Compound	ppm by volume
H2S greater than	160

[**40CFR 60 Subpart J, 6-24-2008**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

B61.X1 The operator shall not use refinery gas containing the following specified compounds:

Compound	ppm by volume
Total Reduced Sulfur (calculated as H2S) greater than	40
Total Reduced Sulfur (calculated as H2S) greater than	30

The 40 ppm limit shall be based on a rolling 3-hour averaging period.
The 30 ppm limit shall be based on a rolling 24-hour averaging period.

Refinery gas is defined as a mixture of refinery fuel gas, produced within the refinery, and natural gas obtained from a utility regulated by the Public Utilities Commission (PUC), for which the natural gas component of the mixture (formed at a point upstream of the sampling location for Total Reduced Sulfur concentration) shall not exceed 50% of the total, by Higher Heating Value (HHV) content.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

B61.X2 The operator shall not use fuel gas, except uncombined natural gas which is not regulated by this condition, containing the following specified compounds:

Compound	ppm by volume
H2S greater than	162
H2S greater than	60

The 162 ppm limit shall be based on a rolling 3-hour averaging period.
The 60 ppm limit shall be based on a rolling 365 successive day average.

[**40CFR 60 Subpart Ja, 6-24-2008**]

[Devices subject to this condition: DX1, DX2]

C1.33 The operator shall limit the duration of shutdown to no more than 4 hour(s).

For the purpose of this condition, “duration of shutdown” shall be defined as the duration prior to extinguishing the flame in the gas turbine.

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

C1.34 The operator shall limit the duration of startup to no more than 8 hour(s).

For the purpose of this condition, “duration of startup” shall be defined as the duration beginning immediately following initial firing of the gas turbine.

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

C1.X1 The operator shall limit the firing rate to no more than 1069.9 MM Btu per hour.

For the purpose of this condition, firing rate shall be defined as energy or heat input of natural gas and refinery gas to the equipment combustion chamber based on the higher heating value (HHV) of the natural gas and refinery gas used.

The refinery gas input to the turbine in any hour shall not exceed 35% of the total volume of gas combusted. Refinery gas shall be as defined in condition B61.X1.

To comply with this condition, the operator shall install and maintain a(n) continuous monitoring system to accurately indicate the energy being supplied to the turbine.

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

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: DX1]

C1.X2 The operator shall limit the firing rate to no more than 510 MM Btu per hour.

For the purpose of this condition, firing rate shall be defined as energy or heat input of natural gas and refinery fuel gas to the equipment combustion chamber based on the higher heating value (HHV) of the natural gas and refinery fuel gas used.

To comply with this condition, the operator shall install and maintain a(n) continuous monitoring system to accurately indicate the energy being supplied to the duct burner.

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

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: DX2]

C157.X The operator shall install and maintain a pressure relief valve with a minimum pressure set at 30 psig.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: DX3]

D12.1 The operator shall install and maintain a(n) continuous monitoring system to accurately indicate the fuel usage at the gas turbine for each fuel being fired.

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

The measuring device or gauge shall be accurate to within + or – 5.0 percent. It shall be calibrated once every 12 months.

[RULE 1303(b)(2)-Offset, 5-10-1996]

[Devices subject to this condition: DX1, D1226, D1233, D1236, D1239]

D12.2 The operator shall install and maintain a(n) continuous monitoring system to accurately indicate the steam-to-fuel ratio at the gas turbine for each fuel fired.

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

The measuring device or gauge shall be accurate to within + or – 5.0 percent. It shall be calibrated once every 12 months.

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

D12.X1 The operator shall install and maintain a(n) continuous monitoring system to accurately indicate the energy input at the gas turbine by measurement of Higher Heating Value (HHV) of refinery fuel gas.

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

For the purpose of this condition, continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The purpose of this condition is to demonstrate compliance with the limitation of refinery fuel gas, as having natural gas accounting for no more than 50% of the Higher Heating Value (HHV) of the mixture, formed at a point upstream of the sampling location for Total Reduced Sulfur concentration.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

D12.X2 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

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

For the purpose of this condition, continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: CX1]

D12.X3 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

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

For the purpose of this condition, continuously record shall be defined as recording at least once every week and shall be calculated based upon the average of the continuous monitoring for the week.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: CX1]

D12.X4 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH_3).

The operator shall also install and maintain a device to continuously record the parameter being measured and to continuously record the ammonia to emitted NO_x mole ratio.

For the purpose of this condition, continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The measuring device or gauge shall be accurate to within + or – 5.0 percent. It shall be calibrated once every 12 months.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: CX1]

D12.X5 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the CO catalyst reactor in inches water column.

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

For the purpose of this condition, continuously record shall be defined as recording at least once every week and shall be calculated based upon the average of the continuous monitoring for the week.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: CX2]

D28.1 The operator shall conduct source test(s) in accordance with the following specifications:

The test shall be conducted at least annually.

The test shall be conducted to determine the NOX emissions at the outlet.

The test shall be conducted to determine the SOX emissions at the outlet.

The test shall be conducted to determine the flow rate at the outlet.

The test shall be conducted to determine the CO emissions at the outlet.

The test shall be conducted to determine the total hydrocarbon emissions at the outlet.

The test shall be conducted to determine the ~~total PM~~ PM10 emissions at the outlet.

The test shall be conducted to determine the NH3 emissions at the outlet.

The test shall be conducted to determine the formaldehyde emissions at the outlet.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

D29.X1 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District method 100.1	1 hour	Outlet of APC No. 5
CO emissions	District method 100.1	1 hour	Outlet of APC No. 5
SOX emissions	Approved District method	District-approved averaging time	Fuel Sample
ROG emissions	Approved District method	1 hour	Outlet of APC No. 5
PM10 emissions	Approved District method	District-approved averaging time	Outlet of APC No. 5
NH3 emissions	Approved District method	1 hour	Outlet of APC No. 5

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

The test shall be conducted within 90 days after achieving maximum production rate, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the test shall measure the fuel flow rate (CFH) for each fuel, Higher Heating Value (HHV) of fuel gas other than natural gas, the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted when this equipment is operating at loads of 90 percent or greater, 75 percent, and 50 percent of maximum design capacity.

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

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

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002**; RULE 2005, 5-6-2005]**

[Devices subject to this condition: DX1, DX2]

D29.X2 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	Approved District method	1 hour	Outlet of APC No. 5

The test shall be conducted and the results submitted to the District within ~~45~~ 60 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 days prior to the test.

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: CX1]

D29.X3 The operator shall conduct source test(s) for the pollutant(s) identified below:

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	Approved District method	District-approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of APC No. 5

The test(s) shall be conducted at least once every three years after the initial source test, required under condition D29.X1.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the test shall measure the fuel flow rate (CFH) for each fuel, Higher Heating Value (HHV) of fuel gas other than natural gas, the flue gas flow rate, and the turbine generating output in MW.

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

The test shall be conducted when the equipment is operating at 90 percent or greater of maximum capacity.

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

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

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

D29.X4 The operator shall conduct source test(s) for the pollutant(s) identified below:

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
PM10 emissions	Approved District method	District-approved averaging time	Outlet of APC No. 5

The test shall be conducted when the equipment is operating at 90 percent or greater of maximum design capacity.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the test shall measure the fuel flow rate (CFH) for each fuel, Higher Heating Value (HHV) of fuel gas other than natural gas, the flue gas flow rate, and the turbine generating output in MW.

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

D82.X1 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv
Concentrations shall be corrected to 15 percent oxygen on a dry basis.
The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.
The CEMS shall be installed and operated, in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD.
The CEMS shall be installed and operated to measure CO concentration over one-hour and three-hour averaging time periods.
The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2)-PSD-BACT, 10-7-1988]**

[Devices subject to this condition: DX1, DX2]

D82.X2 The operator shall install and maintain a CEMS to measure the following parameters:

NOX concentration in ppmv
SOX concentration in ppmv
Concentrations shall be corrected to 15 percent oxygen on a dry basis.
The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine and shall comply with the requirements of Rules 2011 and 2012. During the interim period between the initial startup and provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2011(f)(2) and 2011(f)(3) and Rule 2012(h)(2)

and 2012(h)(3). Within two weeks after the turbine startup date, the operator shall provide written notification to the District of the exact date of startup.

[RULE 2011, 5-6-2005; RULE 2012, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

D90.3 The operator shall periodically analyze the fuel gas for total sulfur content in the refinery gases and butane used in the cogeneration facility according to the following specifications:

The operator shall analyze once every week.

[**RULE 2005, 5-6-2005; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

D90.4 The operator shall continuously monitor the H2S concentration in the fuel gases being burned in this device according to the following specifications:

The operator shall use Gas Chromatograph meeting the requirements of 40CFR60 Subpart J to monitor the parameter.

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

The operator may monitor the H2S concentration at a single location for fuel combustion devices, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned in this device.

[**40CFR 60 Subpart J, 6-24-2008**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

D90.17 The operator shall periodically monitor the H2S concentration at the inlet of this device according to the following specifications:

The Alternative Monitoring Plan (AMP) approved by the United States Environmental Protection Agency (USEPA) on July 11, 2003 for the periodic monitoring and reporting of H2S concentration for refinery gas streams to four WCC turbines.

In addition, the operator shall also comply with all other requirements of the AMP issued by the USEPA on July 11, 2003 for four WCC turbines.

[**40CFR 60 Subpart A, 6-13-2007; 40CFR 60 Subpart J, 6-24-2008**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

D90.X1 The operator shall continuously monitor Total Reduced Sulfur compounds, calculated as concentration of H2S, in the fuel gases being burned in this device according to the following specifications:

The continuous monitoring system shall be approved by the District prior to initial startup.

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

The operator may monitor Total Reduced Sulfur compounds, calculated as concentration of H2S, at a single location for fuel combustion devices if monitoring at this location accurately represents the concentration of Total Reduced Sulfur compounds in fuel gas being burned in this device.

[RULE 2005, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

D90.X2 The operator shall continuously monitor the H2S concentration in the fuel gases being burned in this device according to the following specifications:

The operator shall use Gas Chromatography meeting the requirements of 40CFR60 Subpart Ja to monitor the parameter.

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

The operator may monitor the H2S concentration at a single location for fuel combustion devices, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned in this device.

[40CFR 60 Subpart Ja, 6-24-2008]

[Devices subject to this condition: DX1, DX2]

D94.1 The operator shall install, maintain, and operate a sampling line from the sampling port and made accessible in the gas turbine exhaust duct and after the ~~waste~~ heat recovery boiler in accordance with District guidelines.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996]

[Devices subject to this condition: DX1, D1226, D1233, D1236, D1239]

~~E17.1 The operator shall not use more than 4 of the following items simultaneously:~~

~~Device ID: D1226 [TURBINE, W/ TWO GAS STOP/RATIO VALVES, WITH STEAM INJECTION, DRIVING A 90.87 MVA ELECTRIC GENERATOR, SITE RATED AT 82.72 MW]~~

~~Device ID: D1233 [TURBINE, W/ TWO GAS STOP/RATIO VALVES, WITH STEAM INJECTION, DRIVING A 90.87 MVA ELECTRIC GENERATOR, SITE RATED AT 82.72 MW]~~

~~Device ID: D1262 [BOILER, NO. 42, WITH 2 AIR PREHEATERS AND 2 FORCED DRAFT FANS]~~

~~Device ID: D1226 [TURBINE, W/ TWO GAS STOP/RATIO VALVES, WITH STEAM INJECTION, DRIVING A 90.87 MVA ELECTRIC GENERATOR, SITE RATED AT 82.72 MW]~~

~~Device ID: D1236 [TURBINE, W/ TWO GAS STOP/RATIO VALVES, WITH STEAM INJECTION, DRIVING A 90.87 MVA ELECTRIC GENERATOR, SITE RATED AT 82.72 MW]~~

~~[**RULE 1303(b)(2)-Offset, 5-10-1996**]~~

~~[Devices subject to this condition: D1226, D1233, D1236, D1239]~~

E54.1 The operator is not required to vent this equipment to the following equipment if any of the requirements listed below are met:

Device ID: D2808 [DRUM, KNOCK OUT, VERTICAL, SFIA VAPOR RECOVERY WEST]

Requirement number 1: During periods of startup and shutdown modes

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

E57.X1 The operator shall vent this equipment to dust control equipment whenever SCR catalyst loading/unloading or handling/transport operations produces catalyst fines.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: CX1]

E71.1 The operator shall not fire this equipment during the startup mode of operation.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: D1227, D1234, D1237, D1240]

E73.1 Notwithstanding the requirements of Section E conditions, the operator may, at his discretion, choose not to use steam injection if any of the following requirement(s) are met:

Startup and shutdown modes of operation.

[**RULE 2005, 5-6-2005**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

E73.X1 Notwithstanding the requirements of Section E conditions, the operator may, at his discretion, choose not to use ammonia injection if the following requirement(s) are met:

Temperature measured at the SCR inlet is less than 500 Deg F, not to exceed 3 hours during cold startup.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: CX1]

E144.X The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**]**

[Devices subject to this condition: DX3]

~~E226.1 The following condition number(s) shall only apply if any of the requirement(s) stated below are met:~~

~~Condition number 17-1~~

~~Requirement 1: Boiler No. 42 is in operation~~

~~[**RULE 1303(b)(2)-Offset, 5-10-1996**]~~

~~[Devices subject to this condition: D1226, D1233, D1236, D1239]~~

H23.1 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, SUBPART	J

[**40CFR 60 Subpart J, 6-24-2008**]

[Devices subject to this condition: D1226, D1227, D1233, D1234, D1236, D1237, D1239, D1240]

H23.3 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1173
VOC	40CFR60, SUBPART	GGG

[**RULE 1173, 5-13-1994**; RULE 1173, 2-6-2009; **40CFR60 Subpart GGG, 6-2-2008**]

[Devices subject to this condition: D2585, D2586, D2587, D2588]

H23.18 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
NOX	40CFR60, SUBPART	GG
SOX	40CFR60, SUBPART	GG
H2S	40CFR60, SUBPART	J

[**40CFR60 Subpart GG, 2-24-2006; 40CFR 60 Subpart J, 6-24-2008**]

[Devices subject to this condition: D1226, D1233, D1236, D1239]

H23.19 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, SUBPART	J
NOX	40CFR60, SUBPART	Db

[**40CFR60 Subpart Db, 1-28-2009; 40CFR 60 Subpart J, 6-24-2008**]

[Devices subject to this condition: D1227, D1234, D1237, D1240]

H23.X1 This equipment is subject to the applicable requirements of the following rules and regulations:

Contaminant	Rule	Rule/Subpart
NOX	40CFR60, SUBPART	KKKK
SOX	40CFR60, SUBPART	KKKK

[40 CFR 60 Subpart KKKK, 6-6-2006]

[Devices subject to this condition: DX1]

H23.X2 This equipment is subject to the applicable requirements of the following rules and regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, SUBPART	Ja

[40 CFR 60 Subpart Ja, 6-24-2008]

[Devices subject to this condition: DX1, DX2]

I296.X1 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall, prior to the 1st compliance year hold a minimum NOx RTCs of 99,850 lbs/yr and a minimum SOx RTCs of 31,050 lbs/yr. This condition shall apply during the 1st 12 months of operation, commencing with the initial operation of the gas turbine/heat recovery steam generator.

[2005, 5-6-2005]

[Devices subject to this condition: DX1, DX2]

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

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM Cubic Feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF. Solid PM emissions shall be calculated and expressed as lbs/MMBTU.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen and carbon dioxide levels in the exhaust; fuel flow rate (SCFH) for each fuel fired; Higher Heating Value (HHV), total sulfur concentration, and H2S concentration of refinery fuel gas; the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[RULE 1303(a)(1)-BACT, 5-10-1996; ; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

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

Type and quantity of fuel usage, ammonia usage, actual and corrected NOX emission concentration

[RULE 1303(b)(2)-Offset, 5-10-1996]

[Devices subject to this condition: DX1, D1226, D1233, D1236, D1239]

K67.X1 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Commissioning hours, type of control, and fuel use

Date and time of each start-up and shutdown

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

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

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: DX1, DX2]

ATTACHMENT #1

COMMISSIONING PERIOD ACTIVITIES

The new combustion turbine's commissioning is expected to require a total of 550 hours of operation. The commissioning activities are summarized below.

Commissioning Activities

Stage	Activities	Emissions Controls	Duration (time, hours)
1	1. Combustion turbine first fire 2. Combustion turbine no load testing 3. HRSG boil out	DLN: None SCR/CO: None/None	100 hours
2	1. Steam blow 2. Combustion turbine no load operation	DLN: None SCR/CO: None/None	50 hours
3	1. Combustion turbine generator load testing 2. HRSG steam production	DLN: None SCR/CO: None/None	100 hours
4	1. Combustion turbine DLN combustor tuning 2. Combustion turbine control system tuning	DLN: Partial SCR/CO: None/None	150 hours
5	1. SCR catalyst installation 2. Ammonia Injection/SCR tuning 3. CO catalyst installation	DLN: Full SCR/CO: Partial/Partial	100 hours
6	1. Emissions control final tuning 2. Peak testing 3. Duct burner testing	DLN: Full SCR/CO: Full/Full	50 hours

ATTACHMENT #2

ANNUAL NO_x AND CO EMISSIONS CALCULATIONS

Annual NO_x Emissions
For Average Annual Case (63.1°F Ambient Temperature/60% Relative Humidity)
100% Combustion Turbine/Unfired Duct Burner Emissions = 7.88 lbs NO_x/hr
100% Combustion Turbine/Minimum Fired Duct Burner Emissions = 8.26 lbs NO_x/hr
100% Combustion Turbine/Maximum Fired Duct Burner Emissions = 11.35 lbs NO_x/hr

Annual Events:
4 Cold Start-Ups = 4 events (3 hours each) x 211.24 lbs/event = 844.96 lbs
24 Warm Start-Ups = ~~12~~ 24 events (1 hour each) x 21.32 lbs/event = ~~255.84~~ 511.68 lbs
29 Shutdowns = ~~16~~ 29 events (1 hour each) x 12.85 lbs/event = ~~205.60~~ 372.65 lbs
~~6620~~ 6695 hours Minimum Duct Fired Case = ~~6620~~ 6695 hours x 8.26 lbs/hr = ~~54,681.20~~ 55,300.70 lbs
~~2100~~ 2000 hours Maximum Duct Fired Case = ~~2100~~ 2000 hours x 11.35 lbs/hr = ~~23,835.00~~ 22,700.00 lbs

= ~~79,822.60~~ 79,729.99 lbs / 2000 lbs/ton = 39.9 tons NO_x/year

Annual CO Emissions
For Average Annual Case (63.1°F Ambient Temperature/60% Relative Humidity)
100% Combustion Turbine/Unfired Duct Burner Emissions = 7.20 lbs CO/hr
100% Combustion Turbine/Minimum Fired Duct Burner Emissions = 7.54 lbs CO/hr
100% Combustion Turbine/Maximum Fired Duct Burner Emissions = 10.37 lbs CO/hr

Annual Events:
4 Cold Start-Ups = 4 events (3 hours each) x 300.65 lbs/event = 1,202.60 lbs
24 Warm Start-Ups = 24 events (1 hour each) x 58.72 lbs/event = 1,409.28 lbs
29 Shutdowns = 29 events (1 hour each) x 57.60 lbs/event = 1,670.40 lbs
6695 hours Minimum Duct Fired Case = 6695 hours x 7.54 lbs/hr = 50,480.30 lbs
2000 hours Maximum Duct Fired Case = 2000 hours x 10.37 lbs/hr = 20,740.00 lbs

= 75,502.58 lbs / 2000 lbs/ton = 37.75 tons CO/year

ATTACHMENT #3

TURBINE EMISSIONS UNDER VARIOUS OPERATING SCENARIOS

Case	Operating Conditions	NO_x Emissions (lbs/hr)	CO Emissions (lbs/hr)	VOC Emissions (lbs/hr)	PM_{10} Emissions (lbs/hr)	SO_2 Emissions (lbs/hr)
Case E-1	Ambient Temperature = 36°F; Relative Humidity = 36% Combustion Turbine = 100%; Duct Burner = Unfired	8.22	7.51	2.87	5.00	~~2.84~~ 3.71
Case E-2	Ambient Temperature = 36°F; Relative Humidity = 36% Combustion Turbine = 100%; Duct Burner = Minimum	8.59	7.85	3.00	5.50	~~3.15~~ 4.01
Case E-3	Ambient Temperature = 36°F; Relative Humidity = 36% Combustion Turbine = 100%; Duct Burner = Maximum	11.94	10.91	4.16	9.93	~~5.87~~ 6.74
Case E-4	Ambient Temperature = 59°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Unfired	7.95	7.26	2.77	5.00	~~2.75~~ 3.59
Case E-5	Ambient Temperature = 59°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Minimum	8.33	7.61	2.90	5.50	~~3.06~~ 3.89
Case E-6	Ambient Temperature = 59°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Maximum	11.47	10.47	4.00	9.65	~~5.61~~ 6.44
Case E-7	Ambient Temperature = 85°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Unfired	7.49	6.85	2.61	5.00	~~2.59~~ 3.38
Case E-8	Ambient Temperature = 85°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Minimum	7.87	7.19	2.74	5.50	~~2.90~~ 3.69
Case E-9	Ambient Temperature = 85°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Maximum	10.71	9.78	3.73	9.25	~~5.21~~ 6.00
Case E-10	Ambient Temperature = 102°F; Relative Humidity = 16% Combustion Turbine = 100%; Duct Burner = Unfired	7.48	6.83	2.61	5.00	~~2.67~~ 3.44
Case E-11	Ambient Temperature = 102°F; Relative Humidity = 16% Combustion Turbine = 100%; Duct Burner = Minimum	7.85	7.17	2.74	5.50	~~2.89~~ 3.68
Case E-12	Ambient Temperature = 102°F; Relative Humidity = 16% Combustion Turbine = 100%; Duct Burner = Maximum	10.72	9.80	3.74	9.30	~~5.23~~ 6.01
Annual Average Case 1	Ambient Temperature = 63.1°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Unfired	7.88	7.20	2.75	5.00	~~2.75~~ 3.59
Annual Average Case 2	Ambient Temperature = 63.1°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Minimum	8.26	7.54	2.88	5.50	~~3.06~~ 3.89
Annual Average Case 3	Ambient Temperature = 63.1°F; Relative Humidity = 60% Combustion Turbine = 100%; Duct Burner = Maximum	11.35	10.37	3.96	9.58	~~5.61~~ 6.44

Basis

1. NO_x and VOC concentration of 2 ppm @ 15% O_2.
2. CO concentration of 3 ppm @ 15% O_2.
3. PM_{10} emissions from firing refinery gas and PUC regulated natural gas
4. SO_2 emissions based on fuel H_2S content of: 40 ppm for refinery gas and ~~0.29~~ 0.75 grains/100 cf for natural gas. (The annual average total sulfur content in natural gas, calculated as H_2S, is expected to be 0.29 gr/100 cf, but the short-term total sulfur content may reach 0.75 gr/100 cf.)
5. SO_2 emissions for Annual Average Cases are the same as in Cases 4, 5, and 6 since these have most similar operating conditions.
6. Combustion turbine firing mixture of natural gas (65 ~~wt%~~ vol%) and refinery gas (35 ~~wt %~~ vol%). Duct burner firing only refinery gas.

ATTACHMENT #3 (CONTINUED)

TURBINE OPERATING PARAMETERS

Case	Net Facility Output (kW)	Desuper-heated Steam to Watson Header (lbs/hr)	Fogger Status	Vaporized Ammonia (lbs/hr)	Natural Gas Input - MMBtu/hr (LHV)	Refinery Gas Input - MMBtu/hr (LHV)	Cooling Water, Total (gpm)
Case E-1	90,537	341,457	Off	18	648.4	308.4	2,655
Case E-2	90,478	378,124	Off	19	648.4	349.4	2,655
Case E-3	89,999	680,844	Off	31	648.4	715.2	2,655
Case E-4	85,770	339,143	On	17	627.4	298.5	2,655
Case E-5	85,712	375,670	On	18	627.4	339.5	2,655
Case E-6	85,263	659,293	On	29	627.4	682.1	2,655
Case E-7	78,845	334,148	On	16	591.2	281.3	2,655
Case E-8	78,788	370,492	On	17	591.2	322.3	2,655
Case E-9	78,382	627,188	On	27	591.2	632.3	2,655
Case E-10	79,623	333,956	On	16	576.3	294.0	2,655
Case E-11	79,565	370,333	On	18	589.7	321.6	2,655
Case E-12	79,154	630,046	On	28	589.7	635.1	2,655

Notes: Based on information supplied by the applicant, the LHV of fuels is as follows,
LHV of Natural Gas 926.76 Btu/scf and 20,584.6 Btu/lb
LHV of Refinery Gas 907.03 Btu/scf and 18,188.2 Btu/lb

ATTACHMENT #4

EMISSIONS FACTORS FOR EMISSIONS CALCLATIONS

BP uses the emissions factors, listed below, for PM emissions calculations to demonstration of compliance with condition A63.12.

Natural Gas: 0.00393 lbs PM / MMBtu
Refinery Gas: 0.00402 lbs PM / MMBtu

Therefore, it is proposed to use these factors for calculation of PM_{10} emissions under condition A63.X2 (note: for gas fired equipment it may be assumed that 100% of measured PM emissions are PM_{10}). The following data is from the 2007/2008 source tests of the four cogeneration units:

	Natural Gas Flow Rate (lbs/sec)	**Duct Burner Fuel Gas (MSCFH)**	**PM Emissions Measured (lbs/hr)**	**Emissions Factor lbs PM/MMBtu**
Unit 91 (2007 Test)	11.22	183.38	5.49	0.00497
Unit 92 (2007 Test)	11.86	180.01	5.42	0.00469
Unit 93 (2007 Test)	11.29	212.39	2.98	0.00261
Unit 94 (2007 Test)	11.28	188.40	4.26	0.00382
Unit 91 (2008 Test)	11.49	103.52	1.58	0.00151
Unit 92 (2008 Test)	11.25	128.90	1.65	0.00157
Unit 93 (2008 Test)	11.44	101.25	1.52	0.00146
Unit 94 (2008 Test)	11.53	109.85	1.64	0.00155
Average Emissions Factor				**0.00277**

Notes: Emissions Factor is calculated using Natural Gas HHV of 22,834.6 Btu/lb and Refinery Gas HHV of 998.95 Btu/scf, as are reported in the AFC.

The average emissions factor for the testing conducted over the past two years is 0.00277 lbs PM / MMBtu. Since this average emissions factor, which due to both natural gas and refinery gas combustion, is below both natural gas and refinery gas emissions factors (Natural Gas: 0.00393 lbs PM / MMBtu; Refinery Gas: 0.00402 lbs PM / MMBtu), it is proposed to use these in condition A63.X2. These factors may be amended in the future, based on new source testing results.

ATTACHMENT #4 (CONTINUED)

EMISSIONS FACTORS FOR EMISSIONS CALCLATIONS

Emissions factors for VOC emissions, due to natural gas and refinery gas combustion, proposed for use in condition A63.X1, are calculated below. These are based on the limitation of 2 ppmv @ 15% O_2. The limit will be verified through source testing. The calculations make use of an F_d-Factor of 8710 dscf/MMBtu for natural gas (EPA Method 19) and heating value for natural gas of 1028.05 Btu/scf (from the AFC). Because data for refinery gas in the AFC are very limited, it is required to use values of F_d-Factor and GCV_v obtained from plant measurements.

VOC (lbs/MMscf) = 2 ppm x 16 lb/lb-mole x 20.9% x 8710 dscf/MMBtu x1028.05 Btu/scf /
For Natural Gas 10^6 ppm x (20.9%-15%) x 385 cf/lb-mole

= 2.64 lbs/MMscf

VOC (lbs/MMscf) = 2 ppm x 16 lb/lb-mole x 20.9% x F-Factor x GCV /
For Refinery Gas 10^6 ppm x (20.9%-15%) x 385 cf/lb-mole

= 2.94E-7 x F_d-Factor x GCV_v (units of lbs/MMscf)

Where: F_d-Factor = factor representing the ratio of volume of products of combustion to the heat content of the fuel, dry basis @ 0% excess oxygen, for refinery gas.
GCV_v = gross calorific value of refinery gas in units of Btu/scf.

ATTACHMENT #5

EMISSIONS OF AMMONIA FROM THE STORAGE TANK

The ammonia storage tank will be equipped with a pressure relief valve set to open at 30 psig. At this pressure setting there should be no breathing losses from the tank. The vapor return line will be used to control emissions during filling operations. Emissions during filling operations are calculated below:

Working Loss Calculation:

Lw = 0.0010 x Mv x Pva x Kn x Kp xQ

Where:

Lw = working loss, lbs/yr
Mv = molecular weight of product vapor (lb/lb-mole) = 17 lbs/lb-mole
Pva = vapor pressure at daily average liquid surface temperature
(assume 70◦F daily average liquid surface temperature) = 4.28 psia
Q = volume of liquid pumped into tank = 181,040 gallons/yr = 4,310 barrels/yr
N = tank turnovers = 181,040 gallons/yr / 12,000 gallons x 0.85 maximum fill ratio = 17.7
Kn = working loss turnover (saturation) factor (based on < 36 tank turnovers) = 1
Kp = working loss product factor = 1
Lw = working loss = 0.001 x Mv x P x Kn x Kp x Q
Lw = 0.0010 x 17 x 4.28 x 1 x 1 x 4,310 = 313.60 lbs/yr

Max Yearly Uncontrolled Emissions = 313.60 lbs/yr
Assume control efficiency of vapor return line = 95%
Max Yearly Controlled Emissions = 313.60 lbs/yr x 0.05 = 15.68 lbs/yr
30-Day Average Emissions = 15.68 lbs/yr x (1 / 12 months/yr) x (1 / 30 days) = 0.044 lbs/day

Attachment #6 – Air Quality Modeling and Health Risk Assessment Review Memorandum

SOUTH COAST AIR QUALITY M ANAGEMENT DISTRICT

MEMORANDUM

DATE: July 22, 2009

TO: Jay Chen

FROM: Naveen Berry

SUBJECT: Modeling Review of Watson Cogeneration Company Project

As you requested, Planning, Rule Development & Area Sources (PRA) staff reviewed the modeling conducted for the proposed project. The Watson Cogeneration Company is proposing to install a fifth cogeneration unit to complement the existing four cogeneration units located at a site within the BP Carson Refinery. The cogeneration unit will be rated at 85 MW and will increase the electrical capacity of the facility from 385 MW to 470MW. The applicant has prepared modeling analysis to demonstrate compliance with District rules 1303(b)(1), 2005(b)(1)(B), and 1401. The report (dated March 2009) and electronic files were submitted along with the modeling review requesting memo dated May 21, 2009. Based on our initial review, there was an error in the estimation of health risks from the project and the applicant submitted the revised health risk analysis report on July 20, 2009. Our comments on the modeling conducted in the most recently submitted reports are as follows:

- **Rules 1303 and 2005 - AERMOD Modeling Analysis for NO_2, CO, and PM_{10}**
  - ✓ The applicant utilized AERMOD (version 07026) for the air dispersion modeling, which requires hourly meteorological data. The applicant obtained meteorological data from the Long Beach Airport and upper air sounding data collected at the Miramar Naval Air Station to run AERMET (version 06341). Data from 2002 to 2006 were used. Surface characteristics were determined by using AERSURFACE (version08009). This is consistent with the EPA recommended methodology for the application of AERMOD.
  - ✓ The applicant used the most recent versions of all applicable models except for AERMAP. Version 06341 has been updated with Version 09040. PRA staff review was conducted using this updated version of AERMAP.
  - ✓ The AERMOD modeling utilized the Urban and Regulatory default options and generally conforms to the District's dispersion modeling procedures.
  - ✓ The receptor grid spacing and the area covered are adequate to determine the maximum impacts from the facility.
  - ✓ The source parameters and emission factors used are consistent with the information contained in Table 5.2-18 in the report and the Table I-B-10 in Appendix I-B. The source parameters and emission factors are assumed to be correct.
  - ✓ The applicant has modeled the emissions from the project plus the projects cumulative emissions, which include the existing emissions. PRA staff review only focused on the project only analysis.
  - ✓ The applicant estimated the air quality impacts for the proposed project. The applicant used the highest monitoring data from the most recent three years (2005 through 2007) for SRA 4, South Coast LA County 1 and 2 (Nos. 072 and 077) and SRA 12, South Central LA County (No. 084) monitoring stations to determine the background

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concentrations. The predicted modeling impacts were added to the background concentrations for comparison to the ambient air quality standards, where appropriate.

- ✓ The model results for NO_2, CO, SO_2, PM_{10} and $PM_{2.5}$ for the proposed project are presented in the applicant's report. PRA staff reproduced the modeling analysis and confirmed that the information provided in the March 2009 report and May 21, 2009 requesting memo are consistent with our findings when analyzed. The results of PRA staff's analysis are summarized below.
- ✓ The peak 1-hour NO_2 impact from the project is 28.9 $\mu g/m^3$ and occurs during project commissioning. When added to the worst-case background concentration, the peak 1-hour NO_2 impact is 292.9 $\mu g/m^3$, which is less than the state 1-hour NO_2 standard of 339 $\mu g/m^3$. Background annual NO_2 air quality levels in the impact area exceed the state annual NO_2 standards; therefore, project increments are compared to the Rule 1303 significance thresholds in Table A-2. The peak annual NO_2 impact from the project is 0.09 $\mu g/m^3$, which is less than the annual NO_2 significance change threshold of 1 $\mu g/m^3$.
- ✓ The maximum 1-hour and 8-hour CO impacts occur during project commissioning, where the peak 1-hour and 8-hour CO impacts plus the worst-case background for the proposed project are 9,635 $\mu g/m^3$ and 7,341 $\mu g/m^3$, respectively. These impacts are less than the state 1-hour and federal 8-hour CO standards of 23,000 $\mu g/m^3$ and 10,000 $\mu g/m^3$, respectively.
- ✓ Background PM_{10} air quality in the impact area exceeds the state 24-hour and annual PM_{10} standards; therefore, project increments are compared to the Rule 1303 significance thresholds in Table A-2. The peak 24-hour and annual PM_{10} impacts for the proposed project are 0.36 $\mu g/m^3$ and 0.10 $\mu g/m^3$, respectively. These impacts are less than the Rule 1303 PM_{10} 24-hour and annual significance thresholds of 2.5 $\mu g/m^3$ and 1.0 $\mu g/m^3$, respectively.

- **Rule 1401 - Application of HARP for the Health Risk Impacts**
  - ✓ The applicant performed the risk assessment using AERMOD and the Hot Spots Analysis and Reporting Program (HARP, version 1.4a), which is consistent with District HRA procedures. HARP On-Ramp was used to incorporate the AERMOD results into HARP.
  - ✓ The applicant estimated the health risks for the proposed project.
  - ✓ The PRA staff re-ran the HARP model using the applicant provided data and reproduced the applicant's analysis.
  - ✓ The peak cancer risk for the proposed project is 6.3 in one million for a residential receptor and 1.2 in one million for a worker receptor. The peak acute and chronic hazard indices for the proposed project are 0.008 and 0.02, respectively. These total facility risks are less than the Rule 1401 cancer and non-cancer permit limits of 10 in one million and hazard index of 1, respectively. Therefore, the cancer and non-cancer risks from individual permit units are less than the Rule 1401 permit limits.

Modeling staff spent a total of 40 hours on this review. Please direct any questions to Thomas Chico at ext. 3149.

TC:JB
cc: Rafik Beshai

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Attachment #7 – Certification of Statewide Compliance of Facilities Owned and/or Operated by BP West Coast Products LLC

bp

BP West Coast Products LLC
BP Carson Refinery
2350 E. 223rd Street
Mailing Address: Box 6210
Carson, California 90749-6210
United States of America

Telephone: +1 (310) 816-8100

VIA CERTIFIED MAIL

September 20, 2010

South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182
Attn: Mr. Rafik Beshai

BP CARSON REFINERY FACILITY ID 131003
SCAQMD RULE 1303(b)(5)(B) – STATEWIDE COMPLIANCE

Based on reasonable inquiry and to the best of my knowledge and belief, the major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by BP West Coast Products LLC (BP) in the State of California as listed below are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act:

- BP Carson Refinery, 1801 East Sepulveda Blvd., Carson, CA 90749
- East Hynes Terminal, 5905 Paramount Blvd., CA 90805
- Hathaway Terminal, 2350 Hathaway Drive, Signal Hill, CA 90806
- Marine Terminal 2, 1300 Pier B St., Long Beach, CA 90802
- Carson Crude Terminal, 24696 Wilmington Ave., Carson, CA 90745
- BP Sacramento Terminal, 1601 S. River Rd., West Sacramento 95691
- BP Stockton Terminal, 2700 W. Washington St., Stockton 95203
- BP Vinvale Terminal, 8601 S. Garfield Ave. Southgate, CA 90280
- BP Carson Products Terminal, 2149 E. Sepulveda, Carson, CA 90745
- BP Colton Terminal, 2395 S. Riverside Ave., Bloomington, CA 92316
- BP Wilmington Calciner, 1175 Carrack Ave., Wilmington, CA 90744

If you have any questions please contact Mr. Alan Seese, BP Carson Refinery Environmental Department Manager, at 310.847.5658.

Sincerely,

Jorge Lanza
BP Carson Refinery Business Unit Leader

Map of 22850 Wilmington Ave , Carson, CA by MapQuest

Attachment #8 – Listing of Nearby Schools to the Watson Cogeneration Facility

MAPQUEST

1 **Preferred College of Nursing**
- 0.77 miles away
22010 Wilmington Ave # 101, Carson, CA
310-952-1005

2 **Bonita Street Elementary Schl**
- 1.02 miles away
21929 Bonita St, Carson, CA
| 310-834-8588

3 **Carnegie Middle School** - 1.09 miles away
21820 Bonita St, Carson, CA
310-952-5700

4 **Intercoast Colleges** - 1.23 miles away
1 Civic Plaza Dr, Carson, CA
| 310-847-8400

5 **Carson Christian School** - 1.24 miles away
21828 Avalon Blvd, Carson, CA
| 310-538-5370

6 **Del Amo Elementary School**
- 1.3 miles away
21228 Water St, Carson, CA
| 310-830-5351

7 **Dolores Childrens Ctr** - 1.44 miles away
22309 Catskill Ave, Carson, CA
| 310-830-6987

8 **Catskill Avenue Elementary**
- 1.44 miles away
23536 Catskill Ave, Carson, CA
310-834-7241

9 **Dolores Street Elementary Schl**
- 1.46 miles away
22526 Dolores St, Carson, CA
| 310-834-2565

10 **Broad Avenue Elementary School**
- 1.47 miles away
24815 Broad Ave, Wilmington, CA
| 310-835-3118

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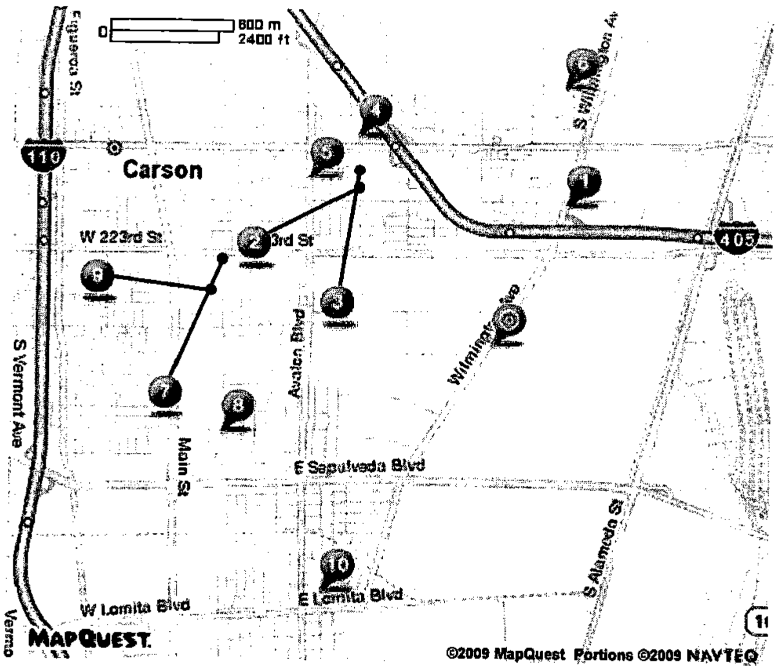
SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 90	PAGE 87
ENGINEERING DIVISION	APPL. NO. See Below	DATE 3/4/11
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY Rafik Beshai	CHECKED BY Tran Vo



Attachment #9 – Results of the 2008 Source Test of the Watson Cogeneration Facility

PROPRIETY INFORMATION STATEMENT

UNITS 91-94
SOURCE EMISSIONS TEST REPORT
FOR THE SCAQMD PERMIT COMPLIANCE
WATSON COGENERATION COMPANY
FACILITY ID 131003
NOVEMBER 19, 20, 21, AND 25, 2008

Source Location:	22850 South Wilmington Avenue Carson, California 90749-6203
Unit Tested:	Heat Recovery Steam Generators/Combustion Gas Turbine Generators (HRSGs/GTGs) Units 91-94
Date Tested:	November 19, 20, 21, and 25, 2008
Prepared For:	Watson Cogeneration Company
Submitted To:	Monitoring and Engineering Monitoring and Analysis Branch South Coast Air Quality Management District 21865 E. Copley Drive Diamond Bar, California 91765-4182
AQE Proj. No.:	08-457
Issue Date:	January 20, 2009

Prepared By:

Thanh Dao, Report Coordinator

Reviewed By:

Sean H. Nguyen, Manager

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2.0 RESULTS SUMMARY

Reference temperature and pressure of 60 °F and 29.92" Hg was used to correct from actual to standard conditions. Concentrations reported are corrected to 15% O_2.

Units 91, 92, 93, and 94 source emissions test results are summarized in Table 1. The table shows that all SCAQMD permit conditions and/or emission limits were met. Continuous emissions monitoring data show that the unit was operating steadily during the test period.

Isokinetic sampling rates for Method 5.2 were clearly within the quality control objective of 100±10 percent.

Pollutant/Parameter	Unit 91	Unit 92	Unit 93	Unit 94	Limit
Oxides of Nitrogen (ppmv)¥	2.24	2.29	2.23	2.45	8
Oxides of Nitrogen (lbs/day)	240.7	232.5	226.9	256	2600‡
Carbon Monoxide (ppmv) ¥	1.19	0.93	0.91	1.04	2.5
Carbon Monoxide (lbs/day)	77.7	57.5	56.3	65.9	568‡
Reactive Organic Gases (lbs/day)	66.6	48.2	74.5	69.7	531‡
Particulate Matter (lbs/day)	37.9	39.7	36.4	39.3	1244‡
Ammonia Slip (ppmv) ¥	10.0	6.61	6.10	12.3	20
Oxides of Sulfur (ppmv) ¥	ND	ND	ND	ND	2
Oxides of Sulfur (lbs/day)	NA	NA	NA	NA	246‡
Formaldehyde (lbs/hr)	0.114	0.167	0.100	0.100	NA

¥ ppmv @ 15% O_2

‡ Combined Limit

NA – Not applicable

ND – Non Detected

TABLE 1

UNITS 91-94 SOURCE EMISSIONS TEST RESULTS SUMMARY
WATSON COGENERATION COMPANY

		UNIT 91	UNIT 92	UNIT 93	UNIT 94	Concentration Limit	Combined Emission Limits
Date Tested	NA	11/19/2008	11/20/2008	11/21/2008	11/25/2008		
Stack Oxygen	%	14.01	14.04	14.24	14.07		
Stack Carbon Dioxide	%	3.96	3.99	3.91	3.95		
Average Stack Volumetric Flow[1]	dscfm	527,745	500,593	516,599	517,129		
Stack Temperature	°F	342	343	335	331		
Stack Moisture Concentration	%	10.0	9.9	8.9	10.5		
DeNO$_x$ Steam Flow	lb/sec	14.6	14.3	14.5	15.0		
Power Produced	MW	86	86	85	86		
Natural Gas Fuel Flow Rate	lb/sec	11.5	11.3	11.4	11.5		
Duct Burner Fuel Flow Rate	mscfh	104	129	101	110		
Ammonia Injection Rate	scfh	1601	1487	1366	1662		
600# Steam Make	mlb/hr	418	418	407	423		
Oxides of Nitrogen as NO_2 - Method 100.1							
at found	ppmv	2.61	2.66	2.52	2.84		
at 15% O_2	ppmv	2.24	2.29	2.23	2.45		
emission rate	lbs/hr	10.03	9.69	9.45	10.67		
	lbs/day	240.68	232.49	226.85	256.00		2600
Carbon Monoxide - Method 10.1							
as found - Sample A	ppmv	1.28	1.14	1.02	1.20		
as found - Sample B	ppmv	1.49	1.02	1.03	<1		
as found - Average	ppmv	1.39	1.08	1.03	1.20		
at 15% O_2	ppmv	1.19	0.93	0.91	1.04	2.5	
emission rate	lbs/hr	3.24	2.39	2.34	2.75		
	lbs/day	77.7	57.5	56.3	65.9		568
VOC as Total Gaseous Non-Methane Organic - Method 25.3							
VOC as TOC in Impinger Vial - Sample A	ppmv	0.56	0.50	0.50	0.65		
VOC as TGNMO in Canister - Sample A	ppmv	1.2	1.11	1.64	2.19		
Combined Vial and Canister Conc. - Sample A	ppmv	1.76	1.61	2.14	2.84		
VOC as TOC in Impinger Vial - Sample B	ppmv	0.63	0.39	0.52	0.54		
VOC as TGNMO in Canister - Sample B	ppmv	1.77	1.17	2.09	1.06		
Combined Vial and Canister Conc. - Sample B	ppmv	2.4	1.56	2.61	1.6		
as found - Average	ppmv	2.08	1.59	2.38	2.22		
at 15% O_2	ppmv	1.78	1.36	2.10	1.92		
emission rate	lbs/hr	2.78	2.01	3.10	2.90		
	lbs/day	66.6	48.2	74.5	69.7		531
Particulate Matter (PM) - Method 5.2							
Stack Volumetric Flow	dscfm	527,745	500,593	516,599	517,129		
Isokinetic Sampling Rate (I)	%	99	101	100	102	90<=I<=110	
Stack Moisture Concentration	%	10.1	10.48	9.76	10.92		
Stack Temperature	°F	342	343	335	331		
Corrected Gas Volume Collected	dscf	123.6	119.854	121.517	125.189		
Stack Total PM Conc.	mg	2.80	3.00	2.70	3.00		
Stack Total PM - at found	gr/dscf	3.49E-04	3.85E-04	3.42E-04	3.69E-04		
Stack Total PM at 15% O_2	gr/dscf	2.99E-04	3.31E-04	3.03E-04	3.19E-04		
Stack Total PM at 3% O_2	gr/dscf	7.76E-04	8.64E-04	8.15E-04	8.36E-04		
PM emission rate	lbs/hr	1.58	1.65	1.52	1.64		
	lbs/day	37.9	39.7	36.4	39.3		1244
Stack Solid PM Conc.	mg	2.80	3.00	2.70	3.00		
Stack Solid PM - at found	gr/dscf	3.49E-04	3.85E-04	3.42E-04	3.69E-04		
Stack Solid PM at 15% O_2	gr/dscf	2.99E-04	3.31E-04	3.03E-04	3.19E-04		
Stack Solid PM Emission Rate	lbs/hr	1.58	1.65	1.52	1.64		
Ammonia Slip - Method 207.1							
Stack Moisture Concentration	%	9.41	8.59	9.41	10.09		
Corrected Gas Volume Collected	dscf	44.344	44.059	45.628	46.372		
NH_3 Conc. in Gas Sample	mg	10.60	6.91	6.45	13.40		
NH_3 Conc. in Gas Sample	gr/dscf	3.68E-03	2.42E-03	2.18E-03	4.45E-03		
NH_3 Conc. in Gas Sample	ppmv	11.7	7.7	6.9	14.2		
NH_3 Conc. in Gas Sample at 15% O_2	ppmv	10.0	6.61	6.1	12.3	20	
Sulfur Oxides as SO_2 - Method 6.1							
Stack Moisture Concentration	%	10.37	10.5	7.52	10.43		
Corrected Gas Volume Collected	dscf	103.664	100.304	103.394	100.1		
SO_x Conc. in Gas Sample	mg	0.39	0.00	0.00	0.00		
SO_x Conc. in Gas Sample	ppmv	0.05	0.00	0.00	0.00		
SO_x Conc. in Gas Sample at 15% O_2	ppmv	0.04	0.00	0.00	0.00	2	
SO_x Emission Rate	lb/hr	0.26	0.00	0.00	0.00		
	lbs/day	6.32	0.00	0.00	0.00		246
Formaldehyde - CARB 430							
Run 1	mg/dscm	0.03901	0.00000	0.02502	0.01244		
Run 2	mg/dscm	0.01222	0.08443	0.01263	0.03608		
Run 3	mg/dscm	0.01284	0.01424	0.01965	0.00893		
Average	mg/dscm	0.02136	0.03289	0.01910	0.01915		
Formaldehyde Conc. in Gas Sample	ppmv	0.017	0.026	0.015	0.015		
Formaldehyde Conc. in Gas Sample at 15% O_2	ppmv	0.018	0.028	0.017	0.017		
Formaldehyde Emission Rate	lb/hr	0.114	0.167	0.100	0.100		
	lbs/day	2.74	4.00	2.40	2.41		