PERMIT TO CONSTRUCT EVALUATION

COMPANY NAME, LOCATION ADDRESS:

Ultramar Inc, SCAQMD ID # 800026
2402 E. Anaheim Street
Wilmington CA 90744

EQUIPMENT DESCRIPTION:

Additions to the equipment description are underlined. New or modified conditions are underlined. Deletions to the equipment description and conditions are noted in strikeouts.

Section D of Ultramar's Facility Permit, ID# 800026

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 15: STEAM GENERATION					
SYSTEM 1: BOILER					
BOILER, 86-B-9000, REFINERY GAS, WITH LOW NOX BURNER, 39 MMBTU/HR WITH A/N: ~~329705~~ <u>527886</u> BURNER, REFINERY GAS, ZURN, MODEL MJ-21, ONE BURNER, LOW NOX BURNER, 39MMBTU/HR	D377		NOX: LARGE SOURCE; SOX: MAJOR SOURCE	**CO**: 400 PPMV (5) [**RULE 1146, 11-17-2000**; RULE 1146, 9-5-2008] ; **CO**: 2000 PPMV (5) [**RULE 407, 4-2-1982** **NOX**: 125 PPMV (3) **[RULE 2012, 5-6-2005]** **PM**: 0.1 GRAINS/SCF (5) [RULE 409,8-7-1981]	<u>A63.x</u>, B61.2, <u>D28.11</u>, <u>D29.x1</u>, D90.3, H23.5
SYSTEM 2: BOILER					
BOILER, 86-B-9001, REFINERY GAS, 127.8 MMBTU/HR WITH A/N: ~~504766~~ <u>527885</u>	D378	C379 (SCR)	NOX: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO**: 2000 PPMV (5) [**RULE 407, 4-2-1982** **NOX**: 0.01 LBS/MMBTU (8) [CONSENT DECREE VALERO, 6-16-2005] **PM**: 0.01 GRAINS/SCF (5B) [**RULE 476, 10-8-1976]**; **PM**: 0.1 GRAINS/SCF (5) [**RULE 409,8-7-1981**];	<u>A63.x</u> , A195.15, A327.1, B61.2, <u>D29.x1</u>, D90.3, D328.1, H23.5

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
				PM: 11 LBS/HR (5A) [**RULE 476, 10-8-1976]**	

Section H of Ultramar's Facility Permit, ID# 800026

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 15: STEAM GENERATION					
SYSTEM 4: BOILER					
BOILER, 86-B-9002, REFINERY GAS, RENTECH BOILER SYSTEMS, MODEL BAF-200/250, 245 MMBTU/HR WITH A/N: ~~504767~~ 527884 Permit to Construct Issued: ~~07/08/10~~ TBD BURNER, REFINERY GAS, COEN, DAF-42, WITH LOW NOX BURNER, 245 MMBTU/HR	D1550	C1551 (SCR)	NOX: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO:** 2000 PPMV (5)[**RULE 407, 4-2-1982**]; **CO:** 50 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002] **NOX:** 0.015 LBS/MMBTU (8) [**CONSENT DECREE VALERO, 6-16-2005]**; **NOX**: 9 PPMV (4) [**RULE 2005, 6-3-2011**]; **NOX:** 7 PPMV (Monthly) (4) [**RULE 2005, 6-3-2011**]; ~~**NOX:** 0.035 LBS/MMBTU REFINERY GAS (1) [**RULE 2012, 6-3-2011**]~~ **PM:** 11 LBS/HR (5A) [**RULE 476, 10-8-1976**]; **PM:** 0.01 GRAINS/SCF (5B) [**RULE 476, 10-8-1976**] **PM:** 0.1 GRAINS/SCF (5) [**RULE 409, 8-7-1981**] ~~**SOX:** 16.9 LBS/MMSCF REFINERY GAS (1) [**RULE 2011, 6-3-2011**]~~	A1.2, A63.x , A99.6~~, A99.7~~, ~~A99.8~~, A195.1, A195.16, A327.1, B61.1. B61.2, ~~D29.9,~~ D29.10, D29.x1, D82.5, D90.3, H23.5, H23.28, K67.10
VESSEL, DEAERATOR, 86-V-1, HEIGHT: 10 FT ; DIAMETER: 7 FT A/N: ~~504767~~ 527884 Permit to Construct Issued: ~~07/08/10~~ TBD	D1552				

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
DRUM, BOILER BLOWDOWN, 86-V-2, LENGTH: 6 FT ; DIAMETER: 4 FT A/N: ~~504767~~ 527884 Permit to Construct Issued: ~~07/08/10~~ TBD	D1553				
TANK, OXYGEN SCAVENGER, 86-TK-2, PORTABLE A/N: ~~504767~~ 527884 Permit to Construct Issued: ~~07/08/10~~ TBD	D1554				
TANK, DISPERSENT/POLYMER, 86-TK-3, PORTABLE A/N: ~~504767~~ 527884 Permit to Construct Issued: ~~07/08/10~~ TBD	D1555				
TANK, AMINE, 86-TK-4, PORTABLE A/N: ~~504767~~ 527884 Permit to Construct Issued: ~~07/08/10~~ TBD	D1556				

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS XX: POWER GENERATION					
SYSTEM 1: COGENERATION					S31.x
GAS TURBINE, 79-GT-1, NATURAL GAS, GENERAL ELECTRIC MODEL NO. LM2500+G4, 341.6 MMBTU/HR (HHV) A/N: 527889 Permit to Construct Issued: TBD	DX1	CX1, CX2	NOX: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO:** 2,000 PPMV (5) [**RULE 407, 4-2-1982**]; **CO:** 4 PPMV (4) **[RULE 1703(a)(2) – PSD – BACT, 10-7-1988**]; **NOx**: 2.5 PPMV (4) [**RULE 2005; 6-3-2011];** **NOx**: 52.3 LBS/MMCF (1) **[RULE 2012; 5-6-2005];** **NOx**: 10.1 LBS/MMCF (1A) **[RULE 2012; 5-6-2005];** **NOx**: 25 PPMV (8) **[40CFR**	A1.x, A63.x, A99.x1, A99.x2, A99.x3, A99.x5, A99.x6, A99.x7, A99.x8, A327.1, A327.x, D12.x1, D29.x2, D29.x3, D82.x1, D82.x2, 90.x1, H23.x2, H23.x3, I297.x1, I297.x2, K40.x1, K67.x1

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
				60 SUBPART KKKK, 7-06-2006]; **PM**: 0.1 GR/SCF (5) - [RULE 409, 8-7-1981]; **PM**: 0.01 GR/SCF (5A) [**RULE 475, 10-8-1976**; RULE 475, 8-7-1978]; **PM**: 11 LBS/HR (5B) [**RULE 475, 10-8-1976**; RULE 475, 8-7-1978]; **SO2**: 0.06 LBS/MMBTU (8A) [**40CFR 60 SUBPART KKKK, 7-06-2006];** **SOx:** 4.1 LBS/MMCF (1) **2011; 5-6-2005];** **SOx:** 3.9 LBS/MMCF (1) [**RULE 2011; 5-6-2005];** **VOC:** 3 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996]**	
DRY LOW-NOX COMBUSTORS	BX1				
GENERATOR, 79-G-1, 34 MW	BX2				
BURNER, DUCT BURNER, , REFINERY GAS, NATURAL GAS, DELTAK OR EQUIVALENT, LOW NOX TYPE, 164.5 MMBTU/HR (HHV) A/N: 527889 Permit to Construct Issued: TBD	DX2	CX1, CX2	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	CO: 2,000 PPMV (5) [**RULE 407, 4-2-1982**]; NOx: 25 PPMV (8) [**40CFR 60 SUBPART KKKK, 7-06-2006];** PM: 0.1 GR/SCF (5**)** [RULE 409, 8-7-1981]; PM: 0.01 GR/SCF (5A) **[RULE 476, 10-8-1976];** PM: 11 LBS/HR (5B) **[RULE 476, 10-8-1976],** SO2: 0.06 LBS/MMBTU (8) **[40CFR 60 SUBPART KKKK, 7-06-2006];**	A1.x, A63.x, A99.x1, A99.x2, A99.x3, A99.x5, A99.x6, A99.x7, A99.x8, A327.x1 B61.x1, B61.x2, D12.x1, D29.x2, D29.x3, D82.x1, D82.x2, D90.x1, D90.x2, H23.x1, H23.x2, H23.x4, I297.x1, I297.x2, K40.x1, K67.x1 ,

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
KNOCKOUT DRUM, 79-V-2, FUEL GAS A/N: 527889 Permit to Construct Issued: TBD	DX3				
SCRUBBER, 79-V-1, NATURAL GAS SUCTION A/N: 527889 Permit to Construct Issued: TBD	DX4				
BOILER, WASTE HEAT RECOVERY STEAM GENERATOR, UNFIRED, A/N: 527889 Permit to Construct Issued: TBD	DX5				
DRUM, 79-V-3, BLOWDOWN A/N: 527889 Permit to Construct Issued: TBD	DX6				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N: 527889 Permit to Construct Issued: TBD	DX7				H23.17
SYSTEM 2: AIR POLLUTION CONTROL FOR COGENERATION					
CO OXIDATION CATALYST, BASF OR APPROVED EQUIVALENT SYSTEM, 150 CU FT; DEPTH: 2.6 IN; WIDTH: 11 FT; HEIGHT: 56 FT A/ N: 527888 Permit to Construct Issued: TBD	CX1	DX1 DX2 CX2			D12.x2, D12,.x5
SELECTIVE CATALYTIC REDUCTION, HALDOR TOPSOE OR APPROVED EQUIVALENT SYSTEM, 425	CX2	CX1 SX		**NH3:** 5 PPMV (4) [**RULE 1303(a)(1)-BACT, 5-10-1996]**	A99.x4, A195.x4, D12.x3, D12.x4, D29.x4, E73.x1

Equipment	**ID No.**	**Connect To**	**RECLAIM Source**	**Emissions and Requirements**	**Conditions**
CU. FT. DEPTH: 13.4 IN; WIDTH: 11 FT; HEIGHT: 56 FT; WITH AMMONIA INJECTION GRID A/ N: 527888 Permit to Construct Issued: TBD	BX3				
VESSEL, 79-ME-1, AQUEOUS AMMONIA VAPORIZER A/ N: 527888 Permit to Construct Issued: TBD	DX8				
STACK, DIAMETER: 9 FT; HEIGHT: 95 FT A/N: 527888 Permit to Construct Issued: TBD	SX	CX2			

PROCESS CONDITIONS

P13.1 All devices under this process are subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
Benzene	40CFR61, SUBPART	FF

[Processes subject to this condition: P1, P2, P3, P4, P5, P7, P8, P9, P10, P11, P12, P14]

[**40CFR 61 Subpart FF, 12-04-2003**]

SYSTEM CONDITIONS

S31.x The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 527889:

All sampling connections shall be closed-purge, closed loop, or closed-vent systems.

All new valves in VOC service shall be leakless type, except those specifically exempted by Rule 1173 or approved by the District in the following applications: heavy liquid service, control valves, 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.

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellows or equivalent approved in writing by the District prior to installation.

All new components in VOC service as defined by 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. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

The following leaks shall be repaired within 7 calendar days -- all light liquid/gas/vapor components leaking at a rate of 500 to 10,000 ppm, heavy liquid components leaking at a rate of 100 to 500 ppm and greater than 3 drops/minute, unless otherwise extended as allowed under Rule 1173.

The following leaks shall be repaired within 2 calendar days -- any leak between 10,000 to 25,000 ppm, any atmospheric PRD leaking at a rate of 200 to 25,000 ppm, unless otherwise extended as allowed under Rule 1173.

The following leaks shall be repaired within 1 calendar day -- any leak greater than 25,000 ppm, heavy liquid leak greater than 500 ppm, or light liquid leak greater than 3 drops per minute.

If 98.0 percent or greater of the new valve 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 revert to a quarterly inspection program with the approval of the Executive Officer. This condition shall not apply to leakless valves.

The operator shall revert from quarterly to monthly inspection program if less than 98.0 percent of the new valves and the new flange population inspected are found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv. This condition shall not apply to leakless valves.

The operator shall keep records of the monthly inspection (quarterly where applicable), subsequent repair, and reinspection, in a manner approved by the District.

The operator shall provide to the District, prior to initial startup, a list of all non-leakless type valves that were installed. The list shall include the tag numbers for the valves and reasons why leakless valves were not used. The operator shall not startup the equipment prior to the Districts approval for the use of all non-leakless valves

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 operator shall also submit a complete, as built, piping and instrumentation diagram(s) and copies of requisition data sheets or field inspection surveys for all non-leakless type valves with a listing of tag numbers and reasons why leakless valves were not used.

[**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 XX, System 1]

DEVICE CONDITIONS:

A. Emission Limits

A1.2 Compliance with the emission limit(s) specified in the emissions and requirements column for this device shall be determined as follows:

Emittant	Emission Limit Type	Averaging time	Compliance Verification Method
CO	(5) - Command and Control	15 minute (3 percent oxygen)	Source test
CO	(4)- BACT	1 hour (3 percent oxygen)	Certified CEMS
NOx	(4)- BACT	1 hour (3 percent oxygen)	Source test, Certified CEMS
PM	(5) - Command and Control	1 hour (3 percent oxygen)	Source test

The NOx BACT identified above applies only to the 9 PPM limit.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 2005, 6-3-2011; RULE 407, 4-2-1982; RULE 409, 8-7-1981; RULE 476, 10-8-1976**]

[Devices subject to this condition: D1550]

<u>A1.x</u> <u>Compliance with the emission limit(s) specified in the emissions and requirements column for this device shall be determined as follows:</u>

<u>Emittant</u>	<u>Emission Limit Type</u>	<u>Averaging time</u>	<u>Compliance Verification Method</u>
<u>CO</u>	<u>(5) - Command and Control</u>	<u>15 minute (15 percent oxygen)</u>	<u>Source test</u>
<u>CO</u>	<u>(4)- BACT</u>	<u>1 hour (15 percent oxygen)</u>	<u>Certified CEMS</u>
<u>NOx</u>	<u>(4)- BACT</u>	<u>1 hour (15 percent oxygen)</u>	<u>Source test, Certified CEMS</u>
<u>PM</u>	<u>(5) - Command and Control</u>	<u>1 hour (15 percent oxygen)</u>	<u>Source test</u>
<u>SOx</u>	<u>(4)- BACT</u>	<u>1 hour (15 percent oxygen)</u>	<u>Source test, Certified CEMS</u>
<u>VOC</u>	<u>(4)- BACT</u>	<u>1 hour (15 percent</u>	<u>Source test</u>

		oxygen)

The above limits are all determined at standard conditions of 68°F and 1 atm.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 2005, 6-3-2011; RULE 407, 4-2-1982; RULE 409, 8-7-1981; RULE 476, 10-8-1976**]

[Devices subject to this condition: DX1, DX2]

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

CONTAMINANT	EMISSION LIMIT
VOC	Less than or equal to 2,981 LBS IN ANY ONE MONTH
PM10	Less than or equal to 4,897 LBS IN ANY ONE MONTH

For the purposes of this condition, the above emission limits shall be based on the combined emissions from Boiler 86-B-9000, Boiler 86-B-9001, Boiler 86-B-9002, Gas Turbine 79-GT-1, and Duct Burner.

The operator shall initially calculate the monthly emissions for VOC and PM10 using the equation below.

Monthly Emissions, lb/ month = (Monthly fuel usage in mmscf/day) * (Emission factors indicated below)

The emission factors for the gas turbine and duct burner during the commissioning period shall be as follows: VOC, 6.20 lb/mmscf; PM10, 14.01 lb/mmscf.

After commissioning, the emission factors of the gas turbine and duct burner shall be as follows: VOC, 4.14 lb/mmscf; PM: 9.78 lb/mmscf.

The emission factors for the boilers 86-B-9000, 86-B-9001, 86-B-9002 shall be as follows: VOC, 5.5 lb/mmscf; PM10, 7.6 lb/mmscf.

The VOC and PM10 emission factors for boilers 86-B-9000, 86-B-9001, 86-B-9002 shall be revised annually based on results of individual VOC and PM10 source tests performed as specified in permit condition D29.x1. The VOC and PM10 emission factor shall be calculated as the average emission rate in lb/mmscf from all valid source test runs during the annual source test.

The VOC and PM10 emission factors for the gas turbine and duct burner shall be revised initially and annually, thereafter, based on the results of individual VOC and PM10 source tests performed as specified in permit conditions D29.x2 and D29.x3. The VOC and PM10 emission factor shall be calculated as the average emission rate in lb/mmscf from all valid source test runs during the annual source test.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

[**RULE 1303(b)(2)–Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; **RULE 1313, 12-7-1995]**

[Devices subject to this condition: D377, D378, D1550, DX1, DX2]

A99.6 The 9 ppm NOx emission limit(s) shall not apply during any startup.

For the purposes of this condition, startup shall be defined as the period when the exhaust temperature of this equipment is below 475 degrees F, which is the minimum ammonia injection temperature.

[**RULE 2005, 6-3-2011**]

[Devices subject to this condition: D1550]

~~A99.7 The 0.035 lb/MM Btu NOx emission limit(s) shall only apply during the interim reporting period to report RECLAIM emissions. The interim reporting period, which is defined as the period between the initial startup of the major NOx source and the provisional approval of the CEMS, shall not exceed 12 months from the initial startup date. The operator shall provide the AQMD with written notification of the initial startup date.~~

~~To comply with this condition, the operator shall install and maintain a(n) non-resettable totalizing fuel meter to accurately indicate the fuel usage of the combustion device.~~

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

~~[**RULE 2012, 5-6-2005**]~~

~~[Devices subject to this condition: D1550]~~

Note: The NOx RECLAIM CEMS has been certified. The emission limit is no longer applicable.

~~A99.8 The 16.9 LBS/MMSCF SOx emission limit(s) shall only apply during the interim reporting period to report RECLAIM emissions. The interim reporting period, which is defined as the period between the initial startup of the major sox source and the provisional approval of the~~

~~CEMS, shall not exceed 12 months from the initial startup date. The operator shall provide the AQMD with written notification of the initial startup date.~~

~~To comply with this condition, the operator shall install and maintain a(n) non-resettable totalizing fuel meter to accurately indicate the fuel usage of the combustion device.~~

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

~~[**RULE 2011, 6-3-2011**]~~

~~[Devices subject to this condition: D1550]~~

Note: The SOx RECLAIM CEMS has been certified. The emission limit is no longer applicable.

A99.x1 The 2.5 PPM NOx emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The turbine commissioning shall not exceed 376 total hours. The turbine shall be limited to a maximum of 20 hours of start-ups and shutdown per year.

For the purposes of this condition, the start-up and shutdown period shall be defined as the initial 30 minute time period when the equipment is shutting down or the initial 60 minute time period when the equipment is starting up and the temperature of the exhaust gas at the inlet of the SCR is below 535 ^{o}F.

NOx emissions shall not exceed 28.4 lbs/startup and 11 lbs/shutdown.

[RULE 1703(a)(2) – PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]

[Devices subject to this condition: DX1, DX2]

Note: The maximum hours of startup and shutdown is based an annual limit instead of a monthly limit because the emissions of NOx and CO are greatest when the shutdowns and startups occurs, while the emissions of VOC, PM10, and SOx are greatest during normal operation (without shutdown and startup).

A99.x2 The 4.0 PPM CO emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The turbine commissioning shall not exceed 376 total hours. The turbine shall be limited to a maximum of 20 hours of start-ups and shutdown per year.

For the purposes of this condition, the start-up and shutdown period shall be defined as the initial 30 minute time period when the equipment is shutting down or the initial 60 minute time period when the equipment is starting up and the temperature of the exhaust gas at the inlet of the SCR is below 535 ^{o}F.

[RULE 1703(a)(2) – PSD-BACT, 10-7-1988]

[Devices subject to this condition: DX1, DX2]

A99.x3 The 3 PPM VOC emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The turbine commissioning shall not exceed 376 total hours. The turbine shall be limited to a maximum of 20 hours of start-ups and shutdown per year.

For the purposes of this condition, the start-up and shutdown period shall be defined as the initial 30 minute time period when the equipment is shutting down or the initial 60 minute time period when the equipment is starting up and the temperature of the exhaust gas at the inlet of the SCR is below 535 ^{o}F.

[**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 5 PPM NH3 emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The turbine commissioning shall not exceed 376 total hours. The turbine shall be limited to a maximum of 20 hours of start-ups and shutdown per year.

For the purposes of this condition, the start-up and shutdown period shall be defined as the initial 30 minute time period when the equipment is shutting down or the initial 60 minute time period when the equipment is starting up and the temperature of the exhaust gas at the inlet of the SCR is below 535 ^{o}F.

With the exception of the commissioning period, the ammonia injection system shall be in full operation at all times that the exhaust gas temperature at the inlet to the SCR is greater than 535 ^{o}F.

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

[Devices subject to this condition: Cx2]

A99.x5 The 52.3 LBS/MMCF NOx emission limit(s) shall only apply during turbine commissioning during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial start up of the turbine.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition: DX1, DX2]

A99.x6 The 10.1 LBS/MMCF NOx emission limit(s) shall only apply after turbine commissioning during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial start up of the turbine.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition: DX1, DX2]

A99.x7 The 4.10 LBS/MMCF SOx emission limit(s) shall only apply during turbine commissioning during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial start up of the turbine.

[**RULE 2011, 5-6-2005**]

[Devices subject to this condition: DX1, DX2]

A99.x8 The 3.9 LBS/MMCF SOx emission limit(s) shall only apply after turbine commissioning during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial start up of the turbine.

[**RULE 2011, 5-6-2005**]

[Devices subject to this condition: DX1, DX2]

A195.1 The 7 ppmv (monthly) NOx emission limit(s) is averaged over a calendar month and is at dry condition, corrected to 3 percent oxygen.

This NOx calendar monthly emission limit shall be calculated based on the measured NOx emissions using a certified RECLAIM CEMS and the heat input during all boiler operating hours for the calendar month except during:

Any District required source test performed without ammonia;
Periods of the exhaust temperature entering the SCR catalyst is less than 475 degrees F, which is the minimum ammonia injection temperature);
RATA testing;
RECLAIM Missing Data period;
Calibration and maintenance periods;
Equipment breakdown periods as defined in Rule 2004; and
Periods of zero fuel flow.

The heat input weighted average NOx concentration shall be calculated using this equation, or other equivalent equation: PPMV at 3 percent oxygen = (Et/Qt) x K, where:

PPMV at 3 percent oxygen = Concentration of NOx in PPMV at 3 percent oxygen
Et = Total measured NOx emissions during the averaging period (excluding exempt periods as noted above)
Qt = Total heat input during the averaging period (excluding exempt periods as noted above)
K =A conversion factor from lbs/MMBtu to PPM, which can be determined using EPA 40 CFR60 Method 19

A data acquisition system (DAS) shall be installed and maintained to record the parameters necessary to determine the calendar monthly NOx concentration. In addition, the DAS shall calculate and display on demand the average monthly NOx PPM.

Any corrections to the DAS data and calculation shall be completed within 72 hours after the end of the calendar month. The recorded parameters and the calculated average monthly NOx PPM shall be kept for a period as stated in the Section E of this facility permit and shall be readily available to the District personnel upon request.

A violation of the 7 PPM NOX limit shall be a violation of the emission limit for the entire averaging period.

[**RULE 2005, 6-3-2011**]

[Devices subject to this condition: D1550]

A195.15 The 0.01 lb/mmBTU NOx emission limit(s) is averaged over 365 rolling days and based on the HHV.

This Consent Decree interim NOx emission limit is calculated by CEMS data measured and recorded in accordance with Rule 2012.

This emission limit shall only apply during the interim emission reduction period from January 1, 2010 to December 31, 2011.

[Consent Decree Valero, 6-16-2005]

[Devices subject to this condition: D378]

A195.16 The 0.015 lb/mmBTU NOx emission limit(s) is averaged over 365 rolling days and based on the HHV.

This Consent Decree interim NOx emission limit is calculated by CEMS data measured and recorded in accordance with Rule 2012.

This emission limit shall only apply during the interim emission reduction period from January 1, 2010 to December 31, 2011.

[Consent Decree Valero, 6-16-2005]

[Devices subject to this condition: D1550]

A327.1 For the purpose of determining compliance with District Rule 476, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

[RULE 476, 10-8-1976]

[Devices subject to this condition: D378, D1550, DX1, DX2]

A327.x For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the 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, DX2]

B. Material/Fuel Type Limits

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

Compound	ppm by volume
Sulfur	less than 100

The operator shall maintain a continuous total sulfur analyzer to monitor the sulfur content of the fuel gas.

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

[Devices subject to this condition: D3, D6, D8, D9, D12, D22, D59, D60, D73, D74, D98, D429, D430, D768, D1550]

B61.2 The operator shall not use fuel gas containing the following specified compounds:

Compound	ppm by volume	
H2S	greater than	160

The H2S concentration limit of 160 ppm shall be based on a rolling 3-hour averaging period at the standard condition of 60 ^{o}F and 14.7 psia, as defined in Rule 102. This H2S concentration limit of 160 ppm is equivalent to 162 ppm at the standard conditions of 68 ^{o}F and 29.92 inches Hg, as defined as 40CFR 60 Subpart A.

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

[Devices subject to this condition: D3, D6, D8, D9, D12, D22, D38, D52, D53, D59, D60, D73, D74, D98, D377, D378, D429, D430, D768, D1550]

B61.x1 The operator shall not use fuel gas containing the following specified compounds:

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

The 60 ppmv limit is based on a rolling 365 consecutive calendar day rolling average. The 162 ppmv limit is based on a rolling 3-hour averaging period.

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

[Devices subject to this condition: DX2]

B61.x2 The operator shall not use fuel gas containing the following compounds:

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

The 40 ppm limit shall be based on a 1-hour averaging time.

For the purposes of this condition, fuel gas is defined as natural gas obtained from a utility regulated by the Public Utilities Commission (PUC) or a mixture of refinery fuel gas, produced within the refinery, and natural gas.

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

[Devices subject to this condition: DX2]

D. Monitoring and Testing Requirements

D12.x1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the turbine and duct burner.

The operator shall also install and maintain a device to continuously record the parameter being measured in accordance with Rule 2012.

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; [**RULE 2012, 5-6-2005**]

[Devices subject to this condition: DX1, DX2]

D12.x2 The operator shall install and maintain a(n) temperature reading device to accurately indicate the temperature at the inlet to the CO catalyst bed.

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 +/- 5 percent. It shall be calibrated once every 12 months.

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

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

[Devices subject to this condition: CX1]

D12.x3 The operator shall install and maintain a(n) temperature reading device to accurately indicate the temperature at the inlet to the SCR catalyst bed.

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 +/- 5 percent. It shall be calibrated once every 12 months.

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

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

[Devices subject to this condition: CX2]

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.

The operator shall also install and maintain a device to continuously record the parameter being measured every 15 minutes.

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

The calibration records shall be kept on site and made available to District personnel upon request.

The ammonia injection system shall be placed in full operation as soon as the minimum temperature at the inlet to the SCR reactor is reached. The minimum temperature is 535 deg F.

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

[Devices subject to this condition: CX2]

D12.x5 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the CO catalyst bed in inches of 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 a week and shall be calculated based upon the average of the continuous monitoring for that week.

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

The pressure drop across the catalyst shall not exceed 6 inches water column.

[**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; RULE 2005, 6-3-2011]**

[Devices subject to this condition: CX1]

D28.11 The operator shall conduct source test(s) in accordance with the following specifications:

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 when this equipment is operating at 80 percent or greater of its maximum design heat rating, or within a capacity approved by the District.

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

The test shall be conducted at least annually. If equipment has not been in operation during the calendar year, the source test does not have to be conducted. The source test shall be conducted in the calendar year the equipment resumes operation. The Facility Permit holder shall keep records to demonstrate that the equipment had not been operated. Upon resumption of operation, the Facility Permit holder shall keep records of each day operated.

[Devices subject to this condition: D377]

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002;**RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 407, 4-2-1982**]

[Devices subject to this condition: D9, D59, D 60, D73, D377]

~~D29.9 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~~
~~CO emissions~~	~~District Method 100.1~~	~~1 hour~~	~~Outlet of the SCR~~
~~PM emissions~~	~~Approved District Method~~	~~District-approved averaging time~~	~~Outlet of the SCR~~
~~NOX emissions~~	~~Approved District Method~~	~~1 hour~~	~~Outlet of the SCR~~
~~NH3 emissions~~	~~District Method 207.1 and 5.3 or EPA Method 17~~	~~1 hour~~	~~Outlet of the SCR~~

~~The test shall be conducted within 60 days after achieving maximum production rate, but no later than 180 days after the construction/modification is completed.~~

~~The test shall be conducted when this equipment is operating at 80 percent or greater of its maximum design heat rating, or within a capacity approved by the District, with ammonia injection.~~

~~During the source test(s), the facility permit holder shall also measure the oxygen levels in the exhaust, flue flow rate (CFH), the flue gas rate, and flue gas temperature.~~

~~In addition to the source test requirements of Section E of this facility permit, the facility permit holder shall submit the protocol to the AQMD engineer no later than 45 days prior to the proposed test date, and notify the District of the date and time of the test at least 10 days prior to the test.~~

~~The operator shall also provide to the District a source test report containing, at a minimum, the following information:~~

~~Required Data~~	~~Reported As~~
~~Emissions data~~	~~Concentration (ppmv) corrected to 3 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM Cubic Feet~~
~~Moisture concentration~~	~~Grains per DSCF~~

~~Exhaust flow rate~~	~~Dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM)~~
~~Flue gas temperature~~	~~Degrees F~~
~~Moisture concentration~~	~~Percent oxygen~~
~~Fuel flow rate (CFH)~~	~~cubic feet per hour (cfh)~~

~~Not withstanding the requirements of Section E conditions, the source test results shall be submitted to the District no later than 60 days after the source test was conducted.~~

~~The test shall be conducted to demonstrate compliance with Rules 1303(a)(1)-BACT, 2005, 407, 409, and 476.~~

~~[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 2005, 6-3-2011; RULE 407, 4-2-1982; RULE 409, 8-7-1981; RULE 476, 10-8-1976**~~]

~~[Devices subject to this condition: D1550]~~

Note: This initial source test has been conducted. The source test results have been reviewed and accepted. This condition is no longer applicable.

D29.10 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
~~PM emissions~~	~~Approved District Method~~	~~District-approved averaging time~~	~~Outlet of the SCR~~
CO emissions	Approved District Method	District-approved averaging time	Outlet of the SCR

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

~~The test shall be conducted when the combustion devices being vented to the SCR are operating under normal operating conditions.~~

The test shall be conducted to demonstrate compliance with Rules 407~~, 409, and 476~~.

[**RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 407, 4-2-1982**~~**; RULE 409, 8-7-1981; RULE 476, 10-8-1976**~~]

[Devices subject to this condition: D1550]

<u>D29.x1 The operator shall conduct source test(s) for the pollutant(s) identified below.</u>

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
PM10 emissions	Approved District Method	1 hour (15 percent oxygen)	Stack Outlet
VOC emissions	Approved District Method	1 hour (15 percent oxygen)	Stack Outlet

The test shall be conducted when this equipment is operating at 80 percent or greater of the maximum design capacity at which ammonia injection occurs during the PM10 test.

The test(s) shall be conducted at least annually. If equipment has not been in operation during the calendar year, the source test does not have to be conducted. The source test shall be conducted in the calendar year the equipment resumes operation. The Facility Permit holder shall keep records to demonstrate that the equipment had not been operated. Upon resumption of operation, the Facility Permit holder shall keep records of each day operated.

The District shall be notified of the date and time of the test at least 10 days prior to the test.

Source test results shall include the following parameters: fuel gas usage of the boiler, ~~and~~ amount of ammonia injected, if applicable, for NOx control, the flue gas flow rate, and Higher Heating Value (HHV) of fuel gas other than natural gas.

The test shall be conducted to demonstrate compliance with Rules 1303(b)(1)-BACT, 1303(b)(2)-Offsets, 409, and 476.

[RULE 1303(b)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 409, 8-7-1981; RULE 476, 10-8-1976]

[Devices subject to this condition: D377, D378 , D1550**]**

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
NOX emissions	District –approved Method	1 hour (15 percent oxygen)	Outlet of the SCR serving this equipment
CO emissions	District – approved Method	15 mins (15 percent oxygen)	Outlet of the SCR serving this equipment
SOX emissions	District-approved method	1 hour (15 percent oxygen)	Stack Outlet
VOC emissions	District –	1 hour	Outlet of the SCR

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
	approved Method	(15 percent oxygen)	serving this equipment
PM10 emissions	District-approved method	1 hour (15 percent oxygen)	Outlet of the SCR serving this equipment
NH3 emissions	District – approved Method	1 hour (15 percent oxygen)	Outlet of the SCR serving this equipment

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

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

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

The test shall be conducted with duct firing when this equipment is operating at maximum, average, and minimum loads at which ammonia injection occurs during the NOx and PM test. The fuel combusted in the duct burner during the source test shall be at least 40% refinery gas.

For the purpose of this condition, alternative test method may be allowed for each of the above pollutants upon concurrence of AQMD, EPA and CARB.

[**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 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 6-3-2011]**

[Devices subject to this condition: DX1, DX2]

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
VOC emissions	District-approved Method	1 hour (15 percent oxygen)	Outlet of the SCR
PM10 emissions	District-approved Method	1 hour (15 percent oxygen)	Outlet of the SCR

The test shall be conducted annually. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

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

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

The test shall be conducted when this equipment is operating at a load of 80 percent or greater of the maximum design capacity at which ammonia injection occurs during the PM test. The fuel combusted in the duct burner during the source test shall be at least 40% refinery gas.

For the purposes of this condition, alternative test method may be allowed for each of the above pollutants upon concurrence of AQMD, EPA, and CARB.

The test shall be conducted for compliance verification of the BACT VOC 3 ppmv limit.

[**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 1703(a)(2)-PSD-BACT, 10-7-1988]**

[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
NH3 emissions	District-approved	1 hour (15	Outlet of the SCR

	Method	percent oxygen)

The test(s) shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted no later than 180 days after initial startup.

The test results submitted to the District within 60 days after the test date.

The test shall be conducted when the gas turbine and duct burner are operating at a load of 80 percent or greater of the maximum design capacity.

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

If the equipment is not operated in any given quarter, the operator may elect to defer the required testing to a quarter in which the equipment is operated.

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

[Devices subject to this condition: CX2]

D82.5 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

The CEMS shall be installed and operated in accordance with an approved AQMD Rule 218 CEMS plan application.

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

[Devices subject to this condition: D1550]

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

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

[**RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 218, 8-7-1981**; RULE 218, 5-14-1999]

[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

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

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

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

[**RULE 1703(a)(2)-PSD-BACT, 10-7-1988**; **RULE 2005, 6-3-2011; [RULE 2012, 5-6-2005**]

[Devices subject to this condition: DX1, DX2]

D90.3 The operator shall continuously monitor the H2S concentration in the fuel gas before being burned in this device according to the following specifications:

The operator shall use an NSPS Subpart J approved instrument meeting the requirements of 40CFR60 Subpart J 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 J, 6-24-2008]

Devices subject to this condition: D3, D6, D8, D9, D12, D22, D38, D52, D53, D59, D60, D73, D74, D98, D377, D378, D429, D430, D768, D1550]

D90.x1 The operator shall continuously monitor the H2S concentration in the fuel gas before being burned in this device according to the following specifications:

The operator shall use an NSPS Subpart Ja approved instrument meeting the requirements of 40CFR60 Subpart J to monitor the parameter.

The operator shall also install and maintain a device to continuously record the parameter being monitored in accordance with NSPS Subpart Ja.

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]

D90.x2 The operator shall continuously monitor the total sulfur compounds calculated as H2S concentration in the refinery fuel gas before being burned in this device according to the following specifications:

The CEMS shall be approved by the District before the initial startup.

The operator shall also install and maintain a device to continuously record the parameter being monitored every 15 minutes.

The operator may monitor the total sulfur compounds 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.

[RULE 2005, 6-3-2011]

Devices subject to this condition: DX2]

D328.1 The operator shall determine compliance with the CO emission limit(s) either: (a) conducting a source test at least once every five years using AQMD method 100.1 or 10.1; or (b) conducting a test at least annually using a portable analyzer and AQMD-approved test method. The test shall be conducted when the equipment is operating under normal conditions to demonstrate compliance with the CO emission limit(s). The operator shall comply with all general testing, reporting, and recordkeeping requirements in Sections E and K of this permit.

[**RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 407, 4-2-1982**]

[Devices subject to this condition: D3, D6, D8, D12, D22, D52, D53, D98, D378, D429, D768]

E. Equipment Operation/Construction Requirements

<u>E73.x1 Notwithstanding the requirements of Section E conditions, the operator may, at his discretion, choose not to use ammonia injection if:</u>

<u>The inlet temperature of the SCR reactor is below 535 ^{o}F.</u>

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

<u>[Devices subject to this condition: CX2]</u>

H. Applicable Rules

H23.5 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: D3, D6, D8, D9, D12, D22, D38, D52, D53, D59, D60, D73, D74, D98, D377, D378, C400, C402, C403, D429, D430, D768, D1550]

H23.17 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1173

[**RULE 1173, 5-13-1994**; RULE 1173, 6-1-2007]

Devices subject to this condition: D872, D1321, D1323, D1353, D1626, <u>DX4</u>]

H23.28 This equipment is subject to the applicable requirements of the following rules or regulations:

Rule	Rule/Subpart
40CFR60, SUBPART	Db

[40 CFR60, Subpart Db, 11-16-2006]

[Devices subject to this condition: D1550]

H23.x1 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, SUBPART	Ja

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

[Devices subject to this condition: DX2]

H23.x2 This equipment is subject to the applicable requirements of the following rules or regulations:

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

[40 CFR 60 Subpart KKKK, 7-6-2006]

[Devices subject to this condition: DX1, DX2]

H23.x3 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
HAPs	40CFR63, SUBPART	YYYY

[40 CFR 63 Subpart YYYY, 4-20-2006]

[Devices subject to this condition: DX1]

H23.x4 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
HAPs	40CFR63, SUBPART	DDDDD

[40 CFR 63 Subpart DDDDD, 5-20-2011]

[Devices subject to this condition: DX2]

I. Administrative

I297.x1 This equipment shall not be operated unless the facility holds 44,137 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

For the purposes of this condition, the above amount of RTCS held shall apply to the combined emissions of the Gas Turbine 79-GT-1 and Duct Burner.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: DX1, DX2]

I297.x2 This equipment shall not be operated unless the facility holds 15,318 pounds of SOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

For the purposes of this condition, the above amount of RTCS held shall apply to the combined emissions of the Gas Turbine 79-GT-1 and Duct Burner.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: DX1, DX2]

K. Recordkeeping/Reporting

K40.x2 The operator shall provide to the District a source test report in accordance with the following specifications:

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

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.

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

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

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the heating content of the fuel, 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; **RULE 1703(a)(2)-PSD-BACT, 10-7-1988**; **RULE 2005, 6-3-2011]**

[Devices subject to this condition: DX1, DX2]

K67.10 The operator shall keep records, in a manner approved by the district, for the following parameter(s) or item(s):

fuel gas usage

fuel gas heating value

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

[Devices subject to this condition: D1550]

K67.x1 The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Refinery fuel gas and natural gas fuel use during the commissioning period.

Refinery fuel gas and natural gas fuel use after the commissioning period and prior to CEMS certification.

Refinery fuel gas and natural gas fuel use after CEMS certification.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: DX1, DX2]

BACKGROUND:

Ultramar, Inc. (Valero Wilmington) is a refinery in the city of Wilmington. The facility is a NOx and SOx RECLAIM, Title V facility. The refinery submitted applications for new construction on a new cogeneration unit consisting of a gas turbine, heat recovery steam generator (HRSG) with duct burner, selective catalytic reduction (SRU), and CO catalytic oxidization unit and for change of condition on three (3) existing boilers at the refinery. Ultramar submitted the applications listed in Table 1:

Table 1 – AQMD Applications Submitted

A/N	Date Submitted	Equipment	Device ID	Requested Action	Previous A/N
527884	10/05/2011	Boiler, > 50 MMBtu/hr, 86-B-9002	D1550	Change of condition	504767
527885	10/05/2011	Boiler, > 50 MMBtu/hr, 86-B-9001	D870	Change of condition	504766/ G9100
527886	10/05/2011	Boiler, >20-50 MMBtu/hr, 86-B-9000	D871	Change of condition	329705/ F10022
527888	10/05/2011	Selective Catalytic Reduction (SCR) System and CO Catalyst	TBD	Construct new SCR and CO oxidation catalyst	n/a
527889	10/05/2011	Gas Turbine, Natural Gas , ≤ 50MW **MASTER APPLICATION**	TBD	Construct new gas turbine, heat recovery steam generator, and duct burner	n/a
527890	10/05/2011	Title V Significant Permit Revision	n/a	n/a	n/a

FEE EVALUTION:

The fees paid for the applications submitted are as follows:

Table 2 – Application Fees Submitted

A/N	Equipment	BCAT	Type	Status	Fee Schedule	Fees Required, $	Fees Paid, $
527884	Boiler, > 50 MMBtu/hr, 86-B-9002	011605	60	21	E	$ 4,572.62	$ 4,572.62
	Expedited Permit Processing	--	--	--	--	$ 2,286.31	$ 2,286.31
527885	Boiler, > 50 MMBtu/hr, 86-B-9001	011605	60	21	E	$4,572.62	$ 4,572.62
	Expedited Permit Processing	--	--	--	--	$ 2,286.31	$ 2,286.31
527886	Boiler, >20-50 MMBtu/hr, 86-B-9000	011604	60	21	D	$3,114.35	$ 3,114.35
	Expedited Permit Processing	--	--	--	--	$ 1,557.18	$ 1,557.18
527887	Steam Generator, Duct Burner, >50 MMBtu/hr	031015	10	20	E	$5,330.66	$ 5,330.66
	Expedited Permit Processing	--	--	--	--	$ 2,665.33	$ 2,665.33
527888	Selective Catalytic Reduction (SCR) System/CO Catalyst	81	10	20	C	$3,359.43	$ 3,359.43
	Expedited Permit Processing	--	--	--	--	$ 1,679.72	$ 1,679.72
527889	Gas Turbine, Natural Gas , $\leq$ 50MW	013008	10	20	D	$4,636.58	$ 4,636.58
	Expedited Permit Processing	--	--	--	--	$ 2,318.29	$ 2,318.29
527890	Title V Significant Permit Revision	555009	85	21	n/a	$1,747.19	$ 1,747.19
Total						$40,126.59	$ 40,126.59

PERMIT HISTORY:

The proposed Cogeneration system is a new unit. Therefore, there is no permit history on the new proposed gas turbine and SCR/CO unit.

The permit history on the boilers is as follows:

Table 3. Boiler Permit History

Boiler 86-B-9002 (D1550):

A/N	Application Type	Permit #	Permit Status	Application Description
504767	60	n/a	n/a	Change of condition to include interim NOx Consent Decree emission limit. Permit to Construct issued July 8, 2010
416628	10	n/a	n/a	Construction of new boiler. Permit to Construct issued on December 16, 2004.

Boiler 86-B-9001 (D378):

A/N	Application Type	Permit #	Permit Status	Application Description
504766	60	G9100	Active	Change of condition to include interim NOx Consent Decree emission limit. Permit to Construct issued July 8, 2010
177991	40	D07102	Inactive	Change of ownership from Union Pacific Resources to Ultramar; Permit to Operate issued in 1989
C41519	10	M37242	Inactive	Construction of new boiler to replace boilers B-900A and B-900B. Permit to Operate issued in 1987.

Boiler 86-B-9000 (D377):

A/N	Application Type	Permit #	Permit Status	Application Description
329705	50	F10022	Active	Change of RECLAIM NOx concentration limit. Permit to Operate issued in 1997.
299331	50	D94767	Inactive	Replace burners and derate boiler to 39 MMBTU/hr from 48.5 MMBtu/hr. Permit to Operate issued in 1995
177554	40	D07027	Inactive	Change of ownership from Union Pacific Resources to Ultramar; Permit to Operate issued in 1989
152368	50	n/a	n/a	Burner modification. Permit to Construct issued in 1987
C27271	20	M34717	Inactive	Construction of new boiler (48.5 MMBtu/hr) ; Permit to Construct issued in 1980; Permit to Operate issued in 1983

PROCESS DESCRIPTION:

Ultramar Inc. is proposing to install a new 34.4 megawatt (MW) Cogeneration Unit at the refinery. The installation of this Cogeneration Unit will stabilize electrical needs and transfer steam production to a more efficient steam generating system. The Los Angeles Department of Water and Power (LADWP) currently supplies the majority of the electricity to the refinery. The refinery also relies on additional steam and electricity from the adjacent Air Products facility. Ultramar has three Boilers 86-B-9000, 86-B-9001, and 86-B-9002 that produces steam for refinery operations. The proposed Cogeneration Unit will replace almost all the power supplied by LADWP during normal operation for the refinery with no anticipated changes to the power and steam received from the Air Products facility. The refinery is required to be connected to the LADWP electrical grid on a continuous basis in order to have LADWP-supplied power available in the event of a planned or unplanned shutdown of the Cogeneration Unit. Under normal operating conditions, Ultramar anticipates 3MW LADWP-supplied power would be the maximum needed. In addition, the Cogeneration Unit will provide up to 260,000 pounds per hour of steam to support the refinery operations. The installation of the Cogeneration Unit will allow the facility's existing boilers to operate at reduced rates. As a result, Ultramar submitted applications for the new equipment associated with the Cogeneration Unit (gas turbine, heat recovery steam generator with duct burner, selective catalytic reduction (SCR) for NOx control, and catalytic oxidation unit for CO control) and change of condition applications for Boilers 86-B-9000, 86-B-9001, and 86-B-9002.

The Cogeneration Unit will consist of the following equipment:

- Combustion gas turbine (CTG), Model GE LM2500+G4, natural gas fired, 341.6 mmBtu/hr (HHV);
- Generator, 34 MW at ambient temperature of 36 ^{o}F;
- Heat recovery steam generator (HRSG) with duct burner, 164.5 mmBtu/hr (HHV) refinery gas and natural gas fired;
- Selective catalytic reduction (SCR) for NOx control;
- Catalytic oxidation unit (a.k.a., CO catalyst) for CO and VOC control; and
- Ancillary support equipment including a static excitation system, electric starting system, evaporative inlet air cooler, packaged electrical/control systems, fire protection system, vibration monitoring, compressor water wash care, and engine and generator lubrication oil systems.

The proposed CTG will be configured as a *combined heat and power type* as opposed to a simple or combined cycle; that is, there will be a HRSG and duct burner to produce additional steam but no additional steam turbine to produce additional electricity. The HRSG will produce 260,000 lbs/hr of 320 psig and 575 ^{o}F steam. The net power generated, after deducting auxiliary power consumption, will be derived solely from the single generator.

A selective catalytic reduction (SCR) system and CO oxidation catalyst will be utilized for control of NOx and CO emissions, respectively. An existing 9,000 gallon ammonia (NH_3) storage tank will provide aqueous ammonia for the SCR. The existing aqueous ammonia delivery system will be modified to include a delivery line to the new SCR unit. No diesel emergency internal combustion engine (black start engine) is proposed to be used to start up the plant in the event of a loss of grid power.

As noted above, the existing Boilers 86-B-9000, 86-B-9001, and 86-B-9002 currently supply most of the steam for the refinery. The Cogeneration Unit will replace most of the production capacity of the existing boilers. To keep the boilers available to produce steam should the Cogeneration Unit unexpectedly shut down, the boilers would be operating at reduced loads. Therefore, Boilers 86-B-9000, 86-B-9001, and 86-B-9002 will be operated at reduced levels when the proposed Cogeneration is in operation but the boilers and new Cogeneration Unit will stay below the overall emissions limit established by the New Source Review balances for the boilers.

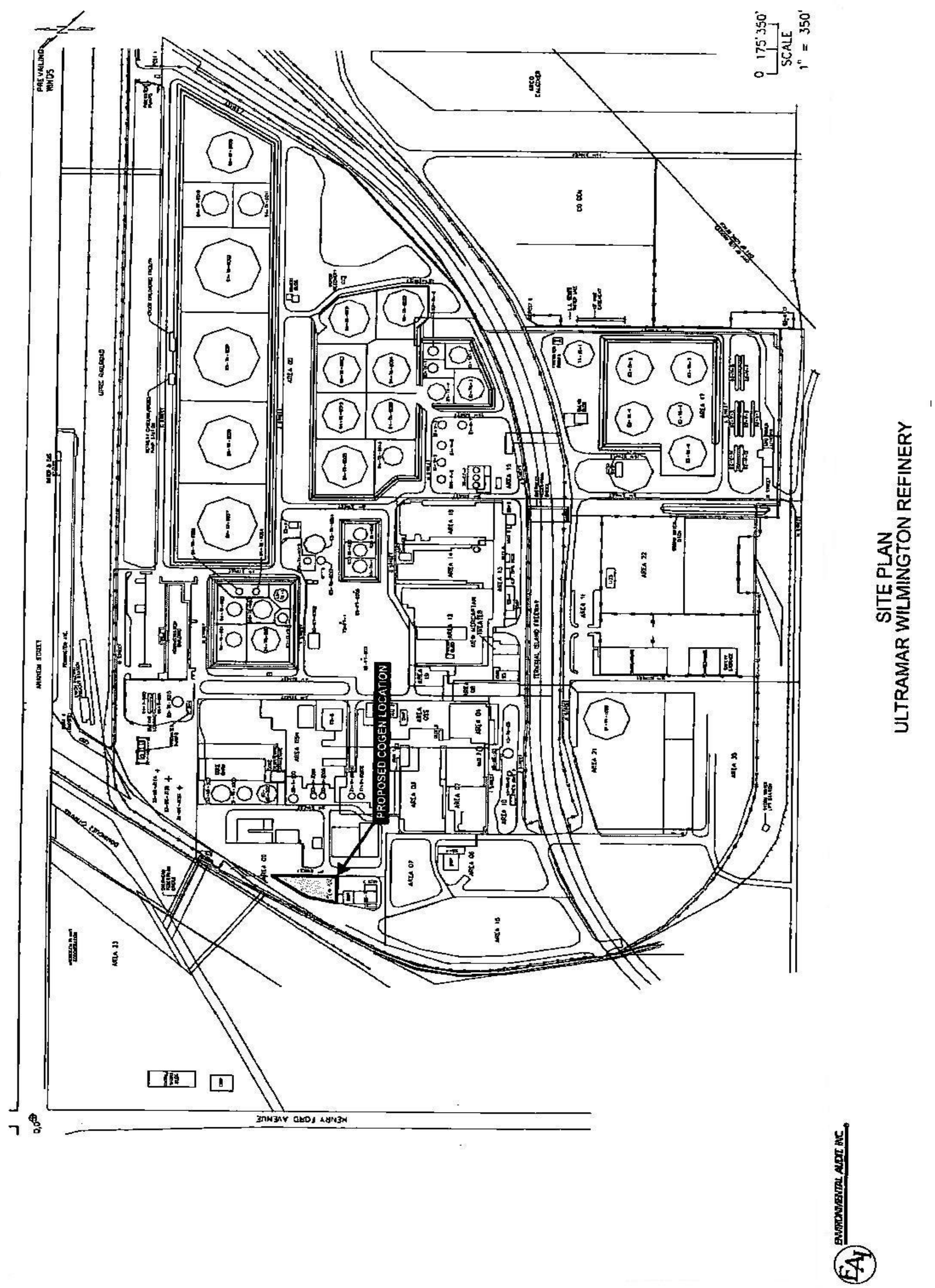
Hence, the overall focus of the proposed project is to generate electricity on-site allowing the refinery to rely mainly on on-site power generation under normal operating conditions as part of an effort to reduce the risk of process upset due to interruption of power supplied by an outside provider (LADWP). In addition, the intent of the permit applications is to allow the flexibility to operate the Cogeneration Unit and boilers to provide reliable electricity and steam to the refinery without an increase in emissions.

California Energy Commission

The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger, including any related facilities such as transmission lines, fuel supply lines, and water pipelines. Since the proposed Cogeneration Unit will be rated at 34.4 MW, no certification from the CEC is required.

Proposed Site

The proposed site of the Cogeneration Unit will be in the West Plant of the facility near the LADWP substation 7. The next figure is the general vicinity aerial map for the proposed site.



SITE PLAN
ULTRAMAR WILMINGTON REFINERY
PROPOSED COGEN LOCATION
0 175' 350'
SCALE
1" = 350'
HENRY FORD AVENUE
ENVIRONMENTAL AUDIT, INC.

Proposed Equipment

Gas Turbine and Heat Recovery Steam Generator (HRSG) with Duct Burner (A/N 527889)
As noted above, Ultramar is proposing to install a **General Electric LM2500** gas turbine, electric generator, and a HRSG with supplemental duct firing. The LM2500 is an industrial and marine gas turbine produced by GE Aviation. The LM2500 is an aeroderivative of the General Electric CF6 aircraft engine. The turbine is an internal combustion engine that operates with rotary motion. The gas turbine is nominally rated 341.6 mmBtu/hour HHV with a gross unit power output of 34.97 MW and net unit power output of 34.54 MW. The gas turbine will be fired on natural gas. The duct burner is rated at 164.5 mmBtu/hour HHV and will be fired with refinery gas blended with natural gas. Ultramar chose to install an aeroderivative engine based on their power demand. The refinery's power demand is approximately 40 MW, whereby 13 MW is purchased from neighboring Air Products. The annual energy usage for the refinery for the past two years is as follows:

Year	Purchased Power (MW)	3rd Party Generated (MW)	Total Power (MW)
2010	27.470	13.060	40.530
2011	25.850	13.380	39.230

Aeroderivative units are sized to produce 13 to 100 MW. Frame engines are sized to produce 43 megawatts (MW) and up. Using a frame unit at Ultramar would be at approximately 63 percent of the operational design of the engine. As a result, the LM2500 series (34 MW) operates in the power range desired by Ultramar. Ultramar has noted that a maximum of 3 MW of power will be supplied from LADWP after the Cogen Unit is installed. The refinery still needs to purchase a nominal amount of electricity on a continuous basis from LADWP to maintain an electrical connectivity to the grid so power could immediately be available in the event of a planned or unplanned shutdown of the Cogen Unit. This connectivity must be maintained regardless of the gas turbine type (Frame vs. Aeroderivative) or size.

The turbine will be used to generate electric power to the refinery and will be operated mainly under base load operating scenario (a.k.a., continuous operation). Combustion air to the gas turbine will be supplied to the gas turbine through an inlet air filter, inlet air evaporative cooling system, and associated inlet air ductwork. Downstream of the air cooling section, the air will be compressed in a compressor prior to being fed to the combustor. The compressed air will be mixed with fuel in the combustor and the mixture will be ignited. The high-pressure, high-temperature gas produced in the combustion chamber is expanded through the turbine blades, driving the turbine, the electric generator, and the turbine compressor. Hot exhaust gas from the turbine will flow through an insulated ductwork to recover the heat in the HRSG, which is exhaust gas heat exchanger. The HRSG will have a duct burner to produce steam for the refinery. Table 4 lists technical specification for the gas turbine and HRSG/duct burner:

Table 4. Combustion Gas Turbine and HRSG/Duct Burner Specifications

Parameter		Specifications
Gas Turbine Manufacturer		General Electric
Gas Turbine Model		LM2500+G4 (Aeroderivative)
Gas Turbine Fuel Type		Natural Gas
Gas Turbine Rating		341.6 MMBTU/hr (HHV)
CTG Heat Input (HHV) at Full Load		280.9 mmBtu/hr (90 °F ambient) 307.6 mmBtu/hr (70 °F ambient) 341.6 mmBtu/hr (36 °F ambient)
CTG exhaust gas temperature at full load		973 °F
Exhaust flow at full load		67.20 acfm w/o duct firing @ 36°F ambient 63.40 acfm w/ duct firing @ 36°F ambient 56.27 acfm w/o duct firing @ 90°F ambient 53.42 acfm w/ duct firing @ 90°F ambient
CTG Gross Power Output		34.97 MW
Net Unit Power Output		34.54 MW
CTG Gross Heat Rate (HHV)		10,349 Btu, HHV/kWh at 90°F ambient
Net Cogeneration Heat Rate (HHV) at Full Load[1]		6,422 Btu, HHV/kW-hr at 90°F ambient
Duct Burner Fuel Type		Refinery Gas and Natural Gas
Duct Burner Rating		164.5 MMBTU/hr (HHV)
Stack flow rate, 1000 lb/hr		765.4
Stack temperature at full load		276 °F
Gross Gas Turbine Heat Rate		8,811 BTU/kW-hr LHV 9,769 BTU/kW-hr HHV
Net Cogeneration Heat Rate		5,032 BTU/kW-hr LHV 6,422 BTU/kW-hr HHV
CO emissions	Cogeneration Outlet	47 ppmv
	SCR Outlet	4 ppmv
NOx emissions	Cogeneration Outlet	42.3 ppmv
	SCR Outlet	2.5 ppmv
VOC emissions	Cogeneration Outlet	4.9 ppmv
	SCR Outlet	3 ppmv
Natural Gas Heating Value (HHV)		22,873 Btu/lb 1,017.6 Btu/SCF 1,050 Btu/SCF (SCAQMD default) used for emission calculations
Refinery Gas Heating Value (HHV)		20,013 Btu/lb 1,143.6 Btu/SCF 1,150 Btu/SCF (SCAQMD default) used for emission calculations

1. Net Cogeneration Heat Rate = (Gas Turbine Fuel Heat Input + Duct Burner Fuel Heat Input – Steam Thermal Energy)/Net Electric Output

Air Pollution Control (APC) Equipment for Gas Turbine (A/N 527888)

Emissions controls will also be located in the HRSG. The HRSG will contain the SCR to control NOx and an oxidation catalyst to remove CO. The CO oxidization catalyst will control CO and VOC emissions down to 4 ppm and 3 ppmv (@15% O2), respectively. The oxidation catalyst will also provide some control of benzene, toluene, ethylene, and xylene (BTEX), formaldehyde, and acetaldehyde emissions. The SCR, which is located downstream of the CO catalyst, will provide control of NOx emissions down to 2.5 ppmv (@15% O2). Specifications for the proposed CO and SCR catalyst are shown in the following tables.

Table 5. Specifications for CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	BASF or equivalent
Catalyst Description	Carnet or equivalent
Catalyst Dimensions	56 ft (h) x 11 ft (w) x 2.6 in (d)
Catalyst Volume	150 ft^3
Catalyst Life (performance guarantee)	4 years
Space Velocity	163324 - 112578 hr^{-1} (36 ^{o}F full load, 100% duct firing)
Minimum Operating Temperature	550 °F
CO Removal efficiency	86.2 % (assuming CO before control: 29 ppmv gas turbine; 47 ppmv duct burner)
CO Concentration @ Stack Outlet	4 ppmvd, 1-hr average, 15% O2
VOC Removal Efficiency	51 %
VOC Concentration @ Stack Outlet	3 ppmvd, 1-hr average, 15% O2
Exhaust gas velocity, feet/sec	12.8 – 15.1 (full load with 100% duct firing)

Table 6. Specifications for Selective Catalyst Reduction (SCR)

Catalyst Properties	Specifications
Manufacturer	Haldor Topsoe or equivalent
Catalyst Description	TiO2/V2O5/WO3
Catalyst Dimensions (per block)	6 ft 2.75 in (h) x 10 ft 8 in (w) x 1 ft 1.4 in (d)
Number of Blocks	9
Configuration	Homogeneous Honeycomb

Catalyst Properties	Specifications
Catalyst Volume	425 ft^3
Space Velocity	5447 -37526 hr^{-1} (36 ^oF full load, 100% duct firing)
Catalyst Life (performance guarantee)	4 years
Minimum Injection Temperature	535 °F*
Exhaust temperature	~ 270 -333 °F
Ammonia Injection Rate	24.25 lb/hr aqueous ammonia
NOx Removal efficiency	> 90 percent (assuming NOx before control: 25.9 ppmv gas turbine; 42.3 ppmv duct burner)
NOx Concentration @ Stack Outlet	2.5 ppmvd, 1-hr average, 15% O2
NH3 Concentration @ Stack Outlet	5 ppmvd, 1-hr average, 15% O2
SO2 at SCR exit	0.023 lb-mol/hr

*This minimum injection temperature was provided by the manufacturer. According to the applicant, different manufacturer's of SCR equipment might have different minimum ammonia injection temperature. Below is a breakdown of some minimum ammonia injection tempts for some cogen units:

Chevron: 597°F
Tesoro: 500°F (Project cancelled in 2013)
BP: 500°F (Project cancelled in 2012)
CPV Sentinel LLC: Maintain inlet tempt to SCR between 740 – 840°F
Walnut Creek: Maintain inlet tempt to SCR between 450 – 750°F
Riverside: None
Canyon Power: 540°F
Burbank: Maintain inlet tempt to SCR between 0 – 900°F

The SCR catalyst will use ammonia injection in the presence of the catalyst to reduce the NOx. Aqueous ammonia will be stored in existing storage tank 33-V-1 (D449 in P14S6). Ammonia will be pumped and evenly distributed across an ammonia injection grid located between the CO oxidation catalyst and SCR and inside the HRSG. The resulting reaction will reduce NOx to elemental nitrogen and water, resulting in NOx concentrations in the exhaust gas at no greater than 2.5 ppmv at 15% O2 on a 1-hour average. The ammonia slip will be limited to 5 ppmvd at 15% O2.

Equipment List

The following table contains the equipment list for the proposed Cogeneration Unit. A process flow diagram is contained in the engineering file.

Table 7. Equipment List of Proposed Cogeneration Unit

Equipment	Device Tag No.	Device ID.
Gas Turbine	79-GT-1	DX1
Generator	79-G-1	BX1
Duct Burner	79-SG-1	DX2
Fuel gas knockout drum	79-V-2	DX3
Natural gas compressor aftercooler	79-C-1A-E1	Not listed on permit
Natural gas suction scrubber	79-V-1	DX4
Natural gas compressors	79-C-1A/B	Not listed on permit
Waste heat recovery steam generator (HRSG)		DX5
CO oxidation catalyst		CX1
Selective Catalytic Reduction (SCR)		CX2
Blowdown drum	79-V-3	DX6
Fugitive Emissions		DX7
Ammonia Vaporizer	79-ME-1	DX8
Gas turbine evaporative cooler and inlet air filter	79-GT-1-F1	Not listed on permit

Existing Equipment

Boiler 86-B-9000 (A/N 527886)
Boiler 86-B-9001 (A/N 527885)
Boiler 86-B-9002 (A/N 527884)

Ultramar operates three existing Boilers 86-B-9000, 86-B-9001, and 86-B-9002 to produce steam for various refinery processes. All three boilers operate on refinery gas. Both Boilers 86-B-9001 and 86-B-9002 are equipped with SCR to control the NOx emissions. For the years 2009, 2010, and 2011, the fuel usage for the boilers was as follows:

Table 8. Boiler Fuel Usage (CY 2009-2011)

Boiler	Maximum Rating		Maximum Annual Fuel Usage	Annual Refinery Gas Fuel Usage mmscf/year		
	mmBtu/hr	mmBtu/year	mmscf/year	2009	2010	2011
86-B-9000	39	341,640	297	0	0	0
86-B-9001	127.8	1,119,528	974	522.10	593.82	777.06
86-B-9002	245	2,146,200	1,866	1,022.20	1,400.65	1,491.93
Total	411.8	3,607,368	3,137	1,544.3	1,994.47	2,268.99

The proposed duct burner to be installed in the HRSG in the Cogeneration Unit will replace most of the steam production capacity of the existing boilers. To keep the boilers available to produce steam during Cogeneration Unit's unexpectedly shut down, scheduled shutdowns, and turnarounds, Boilers 86-B-9000, 86-B-9001, and 86-B-9002 will be operating at reduced loads. Therefore, Ultramar submitted applications for change of conditions to restrict the operation of the boilers to allow the Cogeneration Unit to be installed with no net increase in emissions.

EMISSIONS

Evaluation of Requested Changes of Permit Conditions for Boilers 86-B-9000, 86-B-9001, & 86-B-9002

This section contains a review and analysis of the permit condition changes proposed by Ultramar for existing Boilers 86-B-9000, 86-B9001, and 86-B-9002 and the emissions associated with the condition changes.

Ultramar submitted applications for change of conditions to restrict the operation of Boilers 86-B-9000, 86-B9001, and 86-B-9002 by combining the existing individual emission limits established in New Source Review for PM10 and VOC (non RECLAIM pollutants subject to offsets) for the three boilers and to include the combined emission limits with the newly proposed Cogeneration Unit. That is, Boilers 86-B-9000, 86-B9001, 86-B-9002, Gas Turbine 79-GT-1, and Duct Burner will be subject to a single emission limit in lbs/day for each pollutant.

Each of these existing units was subject to New Source Review (NSR) upon original construction. The original Permits to Operate for Boilers 86-B-9000 and 86-B-9001 were issued in 1983 and 1987, respectively. The Permit to Construct was issued to Boilers 86-B-9002 in 2004. Only the most recently permitted Boiler 86-B-9002 has limits on mass emissions of CO, PM10, and VOC on its permit. The original Permit to Operate for Boiler B-9000 was conditioned with a NOx emission limit. This limit was based on Regulation XIII offset requirements. The emission limit was subsequently subsumed by RECLAIM so it was removed from the RECLAIM Facility Permit. The boiler mass emission limits for CO, PM10, VOC, NOx and SO2 in NSR are shown in the following table.

Table 9. Existing Mass Emission Limits

Boiler	Mass Emission Limit (30-day Average), lbs/day				
	NOx	CO	VOC	PM10	SO2
86-B-9000	94	30	5	15	15.0
86-B-9001	47.8	11.5	47.5	58.7	75.1
86-B-9002	70.98	235.2	46.9	88.2	70.56
Total	212.78	276.7	99.4	161.9	160.7

The VOC and PM10 mass emission limits for Boilers 86-B-9000, 86-B-9001, & 86-B-9002 will be combined into bubble VOC and PM10 limits with the proposed new Cogeneration Unit. As noted in a May 20, 2010 email from Mr. Jay Chen, Senior AQ Engineering Manager of the District's Refinery and Waste Management Permitting, regarding "NSR Emission Bubbles", formation of a combined emission limit that includes a new or modified permit unit along with one or more existing permit units qualifies for the concurrent facility modification offset exemption at Rule 1304(c)(2) if the combined limit represents a reduction in maximum potential emissions calculated according to Rule 1303(d). A copy of Mr. Chen's email is contained in the engineering file. The new combined VOC and PM10 emission limit for Boilers 86-B-9000, 86-B-9001, & 86-B-9002, and new Cogeneration Unit will be 98 lbs/day and 161 lbs/day, respectively. This is one (1) lb/day less than the sum of the current individual VOC and PM10 emission limits for Boilers 86-B-9000, 86-B-9001, & 86-B-9002, (VOC: 5 + 47.5 + 46.9 - 1 = 98 ; PM10: 15 + 58.7 + 88.2 - 1 = 161). Based on the maximum potential VOC and PM10 emissions (30-day average) for the proposed Cogeneration Unit, the VOC and PM10 emissions are 55 and 110 lb/day, respectively, (See Table 21 for 30-day average for new Cogeneration Unit).

Since the Cogeneration Unit's new 164.5 mmBtu/hr duct burner will provide up to 260,000 pounds per hour of steam to support the refinery operations, the facility's three existing boilers can operate at reduced rates. The total maximum firing rate of the three existing boilers is 411.8 mmBtu/hr. The new duct burner is reported to be 40% more efficient than the existing boilers. To keep the boilers available to produce steam during the Cogeneration Unit's unexpected shut downs, scheduled shutdowns, and turnarounds, Boilers 86-B-9000, 86-B-9001, and 86-B-9002 will be operating at reduced loads (roughly between 95 to 133 mmBtu/hr out of the maximum 411.8 mmBtu/hr) while the Cogeneration Unit is operating. The facility cannot completely shutdown the boilers because it would take too long to restart the boilers and reach capacity and thus jeopardize the refinery operation. As a result, Ultramar anticipates curtailing the operation of the boilers in the following four possible scenarios with the proposed Cogeneration Unit operating at 100%.

Table 10. Boiler and Cogeneration Unit Operating Scenarios

Equipment	Device ID	Maximum Firing Rate, MMBtu/hr	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
			Projected Firing Rate, MMBtu/hr	% of Maximum Capacity	Projected Firing Rate, MMBtu/hr	% of Maximum Capacity	Projected Firing Rate, MMBtu/hr	% of Maximum Capacity	Projected Firing Rate, MMBtu/hr	% of Maximum Capacity
Boiler 86-B-9000	377	39	0	0%	0	0%	0	0%	0	0%
Boiler 86-B-9001	378	127.8	48.5	38%	95.3	75%	38.4	30%	0	0%
Boiler 86-B-9002	1550	245	76.8	31%	0	0%	88.5	36%	133	54%
Boiler Total		411.8	125.3	30%	95.3	23%	126.9	31%	133	32%
Gas turbine	DX1	341.6	341.6	100%	341.6	100%	341.6	100%	341.6	100%
HRSG	DX2	164.5	164.5		164.5		164.5		164.5	
Cogen Total		506.1	506.1	100%	506.1	100%	506.1	100%	506.1	100%

Evaluation of Emissions from Cogeneration Unit

This section contains a review and analysis of emissions from the new Cogeneration Unit.

Criteria air pollutant (CO, NOx, PM_{10}, SO2, and VOC) emission estimates are contained in this section. These estimates include emissions for four possible non-emergency operating scenarios such as normal operation, commissioning, planned shutdowns and start-ups. These different modes of operation will affect the emissions profile of the Cogeneration Unit. As a result, the criteria pollutants emissions are evaluated independently. Emissions from emergency events are not included since they cannot be accurately anticipated and estimated.

Greenhouse gas (GHG) emissions were also estimated and contained in this section. These estimates include emissions for normal operation only.

PM2.5 emissions were also estimated for purposes of Rule 1325: Federal $PM_{2.5}$ New Source Review Program.

Normal Operation - Normal operation occurs when the Cogeneration Unit, CO oxidation catalyst, and SCR are working optimally. Emissions may vary slightly during normal operation due to variations in ambient conditions and the age and condition of the CO oxidation catalyst and SCR.

The facility has identified the top eight operating conditions in which fuel consumption of the turbine ranges from a low of 211.2 MMBtu/hr to a maximum of 341.6 MMBtu/hr as shown in Table 11 below:

Table 11. Operating Conditions

	Case Number/Operating Condition							
Parameter	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Ambient Temperature, ^oF	90	70	36	90	70	36	90	36
Relative Humidity, %	32%	64%	67%	32%	64%	67%	32%	67%
Duct Burner Status	ON	ON	ON	OFF	OFF	OFF	ON	ON
Gross Unit Power Output, MW	27.14	30.62	34.97	27.14	30.62	34.97	16.30	20.99
Fuel Consumption, Gas Turbine, HHV, MMBtu/hr	280.9	307.6	341.6	280.9	307.6	341.6	211.2	250.3
Fuel Consumption, Duct Burner, HHV, MMBtu/hr	164.5	164.5	165.4	0	0	0	152.0	164.5
Net Cogeneration Heat Rate, Btu/kW-hr LHV	4,873	4,923	5,032	5,013	5,070	5,189	5,384	5,614
Net Cogeneration Heat Rate, Btu/kW-hr HHV	6,445	6,402	6,422	6,042	6,068	6,158	7,523	7,509
Net Cogeneration Efficiency, % LHV	70.0	69.3	67.8	68.1	67.3	65.8	63.4	60.8
Exhaust Temperature, ^oF	270	273	276	323	328	333	261	266
Evaporative Cooler (on/off)	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Cogeneration Steam Flow, 1000 lb/hr	247.2	252.3	257.4	108.0	112.5	116.7	220.2	235.5

The worst case scenario from an emissions standpoint occurs during periods of maximum fuel consumption (507 MMBtu/hr, Case Number/Operating Condition 3). Based on the information in Table 9, this occurs at full load (34.97 MW), ambient temperature of 36 ^oF, and an exhaust temperature of 276 ^oF and with the duct burner on.

Commissioning - Gas turbine commissioning consists of zero load, partial load and full load testing performed immediately after construction for the purposes of optimizing turbine machinery, gas turbine combustors, and optimizing and testing of the SCR/CO catalysts. Emissions during the commissioning year for NOx, CO, and VOC are expected to be higher than those during a non-commissioning year due to the fact that the combustors may not be optimally tuned and the SCR/CO catalysts may be only partially operational or not operational at all. Commissioning is expected to occur over a one month period (approximately 24 days). A summary of commissioning activities is contained in the following table and the emission details are in Appendix L.

Table 12. Summary of Commissioning Activities

Commissioning Phase	Day	Description
I	1-6	First fire and steam blows. CO catalyst and SCR system are not installed or operational. All emissions are uncontrolled and based on gas turbine exhaust emissions.
II	7-13	CO and SCR catalyst blocks installed, but SCR system has not been commissioned. CO and VOC controlled emission levels reached after 30 minutes of operation.
II	14-24	Plant Tuning, Performance Testing, 72-hour Reliability Test. CO and SCR systems are operational. CO, VOC, and NOx controlled emission levels reached after 30 minutes of operation.

Start-Up (60 minutes) and Shutdown (8-30 minutes) – The proposed Cogeneration Unit will be subject to a number of planned shutdowns such as for maintenance, inspections, and major turnarounds as well as emergency unplanned shutdowns, which will be followed by start-ups.

Startups following planned shutdowns will normally be cold start-ups since the turbine is shutdown for an extended period of time prior to start-up. Occasionally a hot start-up will be performed following an emergency shutdown. Ultramar estimates a shutdown will last 8-30 minutes. A startup will last 1 hour. The GE LMS-2500 is an aeroderivative engine and is therefore able to shutdown and startup quickly. It is assumed all the start-ups as a worst case will be cold start-ups. NOx emissions are high during start-ups because the SCR catalyst bed has not reached optimal temperature to begin the chemical reactions needed to reduce emissions. NO_X emissions are also slightly higher during shutdown than during normal operation because injection of ammonia into SCR ceases during part of the shutdown sequence. The duct burners are not fired during startups and shutdowns. The CO emissions will also be higher during start-ups due to the phased effectiveness of the CO catalyst that gradually come online as the operating temperatures are being reached. Ultramar anticipates a maximum of 20 hours total of startups and shutdowns per year . The Cogeneration Unit will be limited to this 20 hours per year of startup and shutdown since NOx and CO emissions were greatest during the 20 hours of startup and shutdown, while VOC, PM10, and CO were greatest during normal operation (no startups and shutdowns) See Appendix B, Non-Commissioning Year. Table 13 is the projected annual operating for the cogeneration unit for both the Commissioning Year and Subsequent Years.

Table 13. Proposed Annual Operating Schedule For Cogeneration Unit

	1st Year-- Commissioning	**Subsequent Normal Operating Years**
Normal Operations, not including start-ups and shutdowns	8,184 hours [341 days = (365 days– 24 commissioning days)*24 hours/day]	8,760 hours (365 days)
Start-ups and Shutdown, Maximum Start-up , Maximum Range Shutdown, Maximum Range	20 hours total 13-17 hours 13-17 start-ups (60 minutes/start-up) 2-7 hours 14-18 shutdowns (8-30 minutes/shutdown)	20 hours total 13-17 hours 13-17 start-ups (60 minutes/start-up) 2-7 hours 14-18 shutdowns (8-30 minutes/shutdown)
Commissioning	376 hours (24 days)	n/a
Normal Operations, including maximum start-ups, maximum shutdowns, and commissioning (*if applicable)*	~ 8,164 hours (8,184 - 20) hours	~ 8,740 hours (8,760 - 20) hours

Requirements

Criteria pollutant emissions must be estimated to evaluate compliance with various rules or regulations including: Rule 212, Rule 1303, Rule 1325, Regulation XVII and Rule 2005. GHG emissions were estimated for the purposes of Regulation XVII (Rule 1714). For the subject Cogeneration Unit, criteria pollutants will be different during commissioning, shutdowns and start-ups than during normal operation. Therefore, emissions must also be estimated for these periods in some cases. The following table contains a summary of the emission estimate requirements for each rule/regulation and each criteria pollutant.

Table 14.
Summary of Air Pollutant Emission Estimate Requirements

Rule Requirement	Estimate Required	Criteria Pollutant						GHG
		CO	PM10	VOC	NOx	SO2	NH3	
Rule 212 – Public Notice	30-day average (1)	√	√	√	√	√		
Rule 1303(a)(1) - BACT	30-day average (2)		√	√			√	
Rule 1303(b)(1) - Modeling	Max. hourly (1)		√					
	Max. 24-hour (1)		√					
	Annual (1)		√					
Rule 1303(b)(2) - Offsets	30-day average (1)		√	√				
Rule 1303(b)(5) – Major Mod.	30-day average (1)		√	√				
Rule 1325 - Federal $PM_{2.5}$ New Source Review Program			√(4)					
Rule 1703(a)(2) – BACT	Annual (2)	√			√	√		
Rule 1703(a)(3) – Significant Increase	Annual (1)	√			√	√		
Rule 1714 – Significant Increase	Annual (3)							√
Rule 2005(c)(1)(A) - BACT	Max. hourly (3)				√	√		
Rule 2005(c)(1)(B) - Modeling	Max. hourly (1)				√			
	Annual (1)				√			
Rule 2005(c)(2) - RTCs	Annual (1)				√	√		
Rule 3005 – TV Revision Type	30-day average (1)	√	√	√	√	√		

(1) Includes emission estimate for commissioning, planned shutdowns, planned startups, and normal continuous operation.
(2) Includes estimate of planned shutdowns, planned startups, and normal continuous operation.
(3) Includes emission estimate for normal continuous operation only.
(4) $PM_{2.5}$

Methodology

Annual, monthly, and daily-average emissions are evaluated for both a commissioning and non-commissioning year.

Calendar <u>monthly</u> emissions during operation of the Cogeneration were calculated based on the following scenarios:

During Commissioning Year:

1. Twenty-four (24) days of commissioning, twenty (20) hours of startups and shutdowns and 6-days (124 hours) of full operation at the maximum combustion rate of 506.1 MMBtu/hr (HHV)

2. Twenty-four (24) days of commissioning, one (1) hour of startup, and 6 days (143 hours) of full operation at the maximum combustion rate of 506.1 MMBtu/hr (HHV)

3. Twenty-four (24) days of commissioning, one (1) hour of startup, one (1) shutdown (8-30 minutes), and 6 days (143 hours) of full operation at the maximum combustion rate of 506.1 MMBtu/hr (HHV)

During Non-commissioning Year (Subsequent Years):

1. Twenty (20) hours of startups and shutdowns and 30 days (700 hours) of full operation at the maximum combustion rate of 506.1 MMBtu/hr (HHV).

2. One (1) hour of startup, one (1) shutdown (8-30 minutes), and 30 days (719 hours) of full operation at the maximum combustion rate of 506.1 MMBtu/hr (HHV).

3. Thirty (30) days (720 hours) of full operation at the maximum combustion rate of 506.1 MMBtu/hr (HHV)

The commissioning year includes one 24-day commissioning period, 341 days of continuous operation at full load, and 20 hours of startups and shutdowns. The non-commissioning year is comprised of 365 days of continuous operation at full load and 20 hours of startups and shutdowns.

The 30-day average emission estimates specified in the table above are calculated as calendar monthly emissions divided by 30 as specified in Rule 1306. According to Rule 1306(b), calendar monthly emissions are determined from:

(1) the maximum rated capacity; and
(2) the maximum daily or monthly hours of operation as applicable; and
(3) the physical characteristics of the material processed.

30-day average emission estimates must be made for normal operating months as well as commissioning months. As a conservative estimate, it is assumed that the commissioning of the Cogeneration Unit is completed in 24 days. The emissions for a normal operating month must include emission from shutdowns and start-ups. As discussed in the *Process Description* section, Ultramar anticipates a shutdown will last between 8 -30 minutes and a startup will last 1 hour. The permit will be conditioned with a limit of 20 total hours of shutdowns and startups per year.

The CO, NOx and VOC emissions during normal operation are based on the following formula and assumptions:

$$EF\,(lb/MMBTU) = ppmv \times MW \times \left(\frac{1}{MV}\right)\left(\frac{20.9}{20.9-15}\right) \times Fd$$

where,

ppmvd = Pollutant concentration limit at stack outlet at 15% O_2,dry basis
MW = Molecular weight, lb/lb-mol
MV = Molar volume at 68 ^oF = 385.5 dscf/lb-mol
F_d = Dry oxygen f-factor for natural gas = 8,710 dscf/MMBTU

The gas turbine will burn natural gas only. The duct burner in the HRSG will burn fuel gas consisting a mixture of refinery fuel gas and natural gas to meet 40 ppmv H2S. Therefore, the SO2 emissions during normal operation for the gas turbine is based on the maximum sulfur content of natural gas of 1 grain (as H2S)/100 scf natural gas (which is equivalent to 16 ppmv), while the duct burner is based on 40 ppmv H2S limit of refinery gas. The SOx emissions during normal operation and standard operating conditions are based on the following formula and assumptions:

$$SO2\ Emissions = \left[341.6\,MMBtu/hr \times \left(\frac{1}{HHV}\right) \times 16\,ppmv \times MW \times \left(\frac{1}{MV}\right)\right] + \left[164.5\,MMBtu/hr \times \left(\frac{1}{HHV}\right) \times 40\,ppmv \times MW \times \left(\frac{1}{MV}\right)\right] = 1.82\,lb/hr$$

where,

HHV = High heating value of fuel (conservatively assume HHV for natural gas is 1050 Btu/scf and refinery gas is 1150 Btu/scf)
MW = Molecular weight of SO2 (64 lb/lb-mol)
MV = Molar volume at 68 ^oF = 385.5 dscf/lb-mol

PM10 emissions during normal operation are based on the worst case scenario from an emissions standpoint. This occurs during periods of maximum fuel consumption (506 MMBtu/hr, Case Number/Operating Condition 3) where the emissions are 4.1 lbs/hr (Gas Turbine: 2.5 lbs/hr; Duct Burner: 1.6 lbs/hr)[1]. This factor equates to 0.008 lb/mmBtu or 8.88 lb/mmcf based on an assumed high heating value and the maximum fuel consumption of 506 mmBtu/hr of both the gas turbine and duct burner combined. PM is assumed to be equivalent to PM10 for a gaseous fuel fired combustion source. In addition, the use of SCR also has the potential to increase particulate emissions in the form of ammonia sulfate compounds. Because of the sulfur inherent in the fuel burned, SCR oxidizes more of the SO2 into SO3. When the SO3 comes in contact with the unreacted ammonia (ammonia slip), ammonia sulfate compounds (i.e., ammonium sulfate) will be formed. Once the flue gas cools, the sulfate compounds precipitate out in the form of particulate matter. GE estimates the SO2 to SO3 emissions conversion as a result of the gas turbine combustion process is estimated at 5% to 10%, which is based on gathered emissions data.

[1] Steady State Emissions Computation, Rev. I, August 1, 2012, WorleyParsons

Assuming a 10% SO2 to SO3 conversion, PM10 as ammonium sulfate is calculated as follows:

$$\frac{40 \text{ lb-mol total S as H2S}}{10^6 \text{ lb-mol FG}} \times \frac{1 \text{ lb-mol SO2}}{1 \text{ lb-mol H2S}} \times \frac{64 \text{ lb SO2}}{\text{lb-mol SO2}} \times \frac{\text{lb-mol FG}}{385.5 \text{ scf FG}} \times \frac{\text{scf FG}}{1150 \text{ Btu}} \times \frac{506.1 \text{ MMBtu}}{\text{hr}} \times \frac{0.10 \text{ lbs SO3}}{\text{lb SO2}} = \frac{0.292 \text{ lb SO3}}{\text{hr}}$$

$$\frac{0.292 \text{ lb SO3}}{\text{hr}} \times \frac{\text{lb-mol SO3}}{80 \text{ lb SO3}} \times \frac{\text{lb-mol (NH4)}_2\text{ SO4}}{\text{lb-mol SO3}} \times \frac{132 \text{ lb (NH4)}_2\text{ SO4}}{\text{lb-mol (NH4)}_2\text{ SO4}} = \frac{0.48 \text{ lb (NH4)}_2\text{ SO4}}{\text{hr}}$$

The PM10 emission factor from the gas turbine, duct burner, and estimated ammonia sulfate is 4.58 lbs/hr (2.5 + 1.6 + 0.48 lbs/hr). A source test will be required with the SCR on to verify the PM10 emissions.

Therefore, the following assumptions were made in determining the emissions:

1. NOx, CO, and VOC emissions are based on the proposed BACT emission limits.
2. PM10 emissions are based on the worst case scenario from an emissions standpoint. This occurs during periods of maximum fuel consumption (507 MMBtu/hr, Case Number/Operating Condition 3).
3. Ammonia sulfate emissions from the APC equipment (SCR) is accounted for in the PM10 emission factor. Since it is the sulfur inherent in the fuel burned in the gas turbine and duct burner that forms SO2 and eventually SO3 and ammonia sulfate in the SCR, the PM10 is attributed to the cogeneration unit.
4. SOx emissions are based on 16 ppmv sulfur limit for natural gas (1 grain of sulfur per 100 scf) and 40 pmv sulfur limit for refinery gas.

Table 15. Steady State (Normal), Full Load Emission Rates of Cogeneration Unit

Pollutant	Basis – Concentration Limit or Emission Factor	Maximum Hourly Uncontrolled Emissions (lb/hr)	Maximum Hourly Controlled Emissions (lbs/hr)	Maximum Daily Controlled Emissions (lbs/day)
NOx	2.5 ppmv (1-hr avg)	47.89	4.66	111.84
CO	4 ppmv (1-hr avg)	36.46	4.54	108.96
VOC	3 ppmv (1-hr avg)	1.99	1.94	46.56
PM10		4.1	4.58	109.92
	Natural Gas: 0.0073 lb/mmBtu;	2.5	2.5	
	Refinery Gas: 0.0097 lb/mmBtu	1.6	1.6	
	Ammonium sulfate	--	0.48	
SOx		1.824	1.824	43.78
	Natural Gas: 1 grain/100 cf (16 ppm);	0.875	0.875	
	Refinery Gas: 40 ppm (1-hr avg)	0.949	0.949	

Pollutant	Basis – Concentration Limit or Emission Factor	Maximum Hourly Uncontrolled Emissions (lb/hr)	Maximum Hourly Controlled Emissions (lbs/hr)	Maximum Daily Controlled Emissions (lbs/day)
NH3	5 ppmv (1-hr avg)	0 (SCR off)	3.44 (SCR on)	82.56

Notes:

1. Emissions data are from Case Number and Operation Condition No. 3, Rev. I, August 1, 2012, Steady State Emissions Computation, Ambient Temperature = 36 ^{o}F, Relative Humidity = 67%, Maximum Firing of Gas Turbine and Duct Burner. See Appendix A and Appendix H.
2. No startup/shutdown emissions in hourly or daily emissions
3. Controlled emission based on the following removal/control efficiencies: NOx: 90%, CO: 84%; VOC: 50%. These control efficiencies are based on expected uncontrolled emissions controlled to BACT limits of NOx: 2.5 ppmv; CO: 4 ppmv; VOC: 3 ppmv
4. Maximum Daily Controlled Emissions = Maximum Hourly Controlled Emissions x 24 hours/day

The maximum hourly emissions are shown in the following table.

Table 16. Maximum Hourly Cogeneration Unit Emissions

Type Operation	Emissions (lb/hr)				
	NOx	CO	VOC	PM10	SO2
Normal (1)	4.66	4.54	1.94	4.58	1.82
Shutdown (2)	22.00	18.20	2.00	2.60	0.40
Startup (3)	28.40	18.70	0.9	2.50	0.90
Commissioning (4)	14.39	7.87	1.74	3.94	1.13

(1) Operation at full load of 506.1 MMBtu/hr (HHV). Based on NOx at 2.5 ppm, CO at 4 ppm, VOC at 3 ppm (all at 15% O2) stack limit. SOx and PM10 emissions from Steady State Emissions Computation, Rev. I, Worley Parsons, August 1, 2012, Case Number and Operating Condition. 3. SO2 emission estimates based on 40 ppmv sulfur limit for refinery fuel gas and 16 ppm sulfur limit for natural gas. See Appendix A for details of hourly emission factor.

(2) Based on consultants/manufacturers estimates: Shutdown Emissions Calculations @ 36 ^{o}F NG, Maximum Hourly Emissions, 03/2013. Detailed estimates for shutdown are contained in Appendix J. Event time ranges from 8 to 30 minutes.

(3) Based on consultants/manufacturers estimates: Startup Emissions Calculations @ 36 ^{o}F NG, Maximum Hourly Emissions, 03/2013. Detailed estimates for startup are contained in Appendix K. Event time is 60 minutes.

(4) Estimated Commission Emissions, 03/2013, Worley Parsons, Commissioning Duration: 24 days, 376 hours. Detailed estimates for commissioning are contained in Appendix L.

Table 17. Commissioning, Shutdown and Start-up Cogeneration Unit Emissions (Per Event)

Event	Emissions (lb/event)				
	NOx	CO	VOC	PM10	SO2
One Shutdown (8-30 minutes) (1)	11	9.1	1.0	1.3	0.2
One Cold Startup (1 hour) (1)	28.4	18.7	0.9	2.5	0.9
Commissioning (24 days, 376 hours) (1)	5,412	2,958	655	1,480	424

(1) Based on manufacturers estimates. Detailed estimates for shutdown, startup, and commissioning are contained in Appendices J through L.

Table 18. Maximum Monthly Cogeneration Unit Emissions (30-day Month)(1)

Type Operation	Emissions (lb/month)				
	NOx	CO	VOC	PM10	SO2
Commissioning Month (2)(3)	6,670.64	4,002.66	934.06	2,138.13	685.12
Normal Month (4)	3,942.80	3,659.70	1,396.80	3,297.60	1,310.40

(1) Combustion emissions only; Fugitive emissions are not included.
(2) Assumes commissioning is completed in a 24-day month. Commissioning does not include startup.
(3) Emissions for the following scenario that yields the highest emissions:
NOx, CO: 24 days of commissioning, 20 hours of startups (17 hours) and shutdowns (3 hrs), normal operation at full load for 6 days (124 hours);
VOC, PM10, SOx: 24 days of commissioning, one startup (1 hour), one shutdown (8 min), and normal operation at full load for 7 days (142.9 hours).
See Appendix B-Commissioning for details.
(4) Emissions for the following scenario that yields the highest emissions:
NOx, CO: 20 hours of startups (17 hours) and shutdowns (3 hrs), normal operation at full load for 30 days (700 hours);

VOC, PM10, SOx: Normal operation at full load for 30 days (720 hours).
See Appendix B-Non Commissioning for details.

Table 19. Daily (30-day Average) Cogeneration Unit Emissions (1)

Type Operation	Emissions (lb/day)				
	NOx	**CO**	**VOC**	**PM10**	**SO2**
Commissioning Month (2)(3)	222	133	31	71	23
Normal Month (3)	131	122	47	110	44

(1) Combustion emissions only. Fugitive emissions are not included.
(2) Assumes commissioning is completed in a 24-day month.
(3) 30-day average emissions = (maximum monthly emissions) / 30
See Appendix C for details.

Table 20. Maximum Annual Cogeneration Unit Emissions (1)

Type Operation		Emissions (lb/year)				
		NOx	**CO**	**VOC**	**PM10**	**SO2**
Commissioning Year (2)	lbs/year	44,137	40,504	16,532	39,962	15,318
	tons/year	22	20	8	19	8
Normal Year (3)	lbs/year	41,409	40,161	16,994	40,121	15,943
	tons/year	21	20	9	20	8

(1) Combustion emissions only. Based on 365-day year
(2) Emissions for the following scenario that yields the highest emissions:
NOx, CO: 24 days of commissioning, 20 hours of startups (13 hours) and shutdowns (minimum 8 minutes each for 3 hours), normal operation at full load for 341 days (8,164 hours);
VOC, PM10, SOx: 24 days of commissioning, 1 startup (1 hour), 1 shutdown (8 min), normal operation at full load for 341 days (8,182.9 hours).
SOx: 24 days of commissioning, 1 startup (1 hour), normal operation at full load for 341 days (8,183 hours).
See Appendix D-Commissioning for details.
(3) Emissions for the following scenario that yields the highest emissions:
NOx, CO: 20 hours of startups (13 hours) and shutdowns (3 hours), normal operation at full load for 341 days (8,740 hours);
VOC, PM10, SOx: Normal operation at full load for 365 days (8,760 hours)
See Appendix D-Non Commissioning for details.

In addition to the combustion related emissions, the new Cogeneration Unit will have VOC emissions from fugitive components due to the use of refinery gas. VOC emissions for these fugitive components are estimated by multiplying the total number of each fugitive component type by an appropriate emission factor. Emissions from fugitive components are calculated using the CAPCOA-revised 1995 EPA Correlation Equations (Table IV-3a from AQMD Guidelines for Fugitive Emissions Calculations, June 2003). As seen in the detailed fugitive VOC emission calculations, which are contained in Appendix I**,** the fugitive VOC emissions for the Cogeneration permit unit are estimated to be 8.09 lb/day. Total VOC emissions, including the 47 lb/day of combustion related VOC emissions, are estimated to be **<u>54.65 lb/day</u>**.

Table 21. Boiler and Cogeneration Unit Operating Scenarios and Emissions

Equipment	Device ID	Maximum Firing Rate, MMBtu/hr	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
			Projected Firing Rate, MMBtu/hr	% of Maximum Capacity	Projected Firing Rate, MMBtu/hr	% of Maximum Capacity	Projected Firing Rate, MMBtu/hr	% of Maximum Capacity	Projected Firing Rate, MMBtu/hr	% of Maximum Capacity
Boiler 86-B-9000	377	39	0	0%	0	0%	0	0%	0	0%
Boiler 86-B-9001	378	127.8	48.5	38%	95.3	75%	38.4	30%	0	0%
Boiler 86-B-9002	1550	245	76.8	31%	0	0%	88.5	36%	133	54%
Boiler Total		411.8	125.3	30%	95.3	23%	126.9	31%	133	32%
Boiler Emissions, lb/day[1] 30-day average		NOx	28.23		22.87		28.33		28.73	
		CO	86.63		34.81		93.44		119.35	
		VOC	19.80		10.94		20.86		24.71	
		PM10	19.61		14.92		19.86		20.82	
		SOx	44.19		33.61		44.76		46.91	
Gas turbine	DX1	341.6	341.6	100%	341.6	100%	341.6	100%	341.6	100%
HRSG	DX2	164.5	164.5		164.5		164.5		164.5	
Cogen Total		506.1	506.1	100%	506.1	100%	506.1	100%	506.1	100%
Cogen Emissions, lb/day[2] 30-day average Non-commissioning year		NOx	131.43							
		CO	122							
		VOC	46.56 + 8.09 (fugitives) = 54.65							
		PM10	109.92							
		SOx	43.68							
Total Cogen and Boiler Emissions, lb/day[1] 30-day average Non-commissioning year		NOx	159.66		154.30		159.76		**160.15**	
		CO	208.62		156.80		215.43		**241.34**	
		VOC	74.46		65.59		75.52		**79.36**	
		PM10	129.53		124.84		129.78		**130.74**	
		SOx	87.87		77.29		88.44		**90.59**	

1 See Appendix N

2 See Appendix B and N

GHGs Emissions

GHGs as defined by EPA mean the air pollutant as an aggregate group of six GHGs: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The GHG emissions associated with the Cogen Unit during normal operation (non-commissioning) are shown in Table 22.

Table 22
Cogen Unit GHG Emissions Estimates

Cogen	Duty (mmbtu/hr)	Hours Per Year	CO2eq (tonnes/yr)
Turbine	341.6	8760	158,735.1
HRSG	164.5	8760	89,872.9
Total CO2eq, tonnes/yr			248,608.0
Total CO2eq, short tons/yr			274,040.6
Total GHG- Mass Basis (CO2 + N2O + CH4), short tons/yr			273,908.4

See the discussion under Rule 1714 for details on how the GHG emissions were calculated.

<u>RULES EVALUATION:</u>

PART 1 SCAQMD REGULATIONS

Rule 212	Standards for Approving Permits	November 14, 1997
	In accordance with Rule 212(c), a significant project is a new or modified facility in which: (1) the new or modified permit unit is located within 1000 feet of a school; (2) the new or modified facility has on-site emission increases exceeding the daily maximum specified in subdivision (g); or (3) the new or modified permit unit has an increased cancer risk greater than, or equal to, one in a million ($1x 10^{-6}$) during a lifetime of 70 years or pose a risk of	

Rule 212	**Standards for Approving Permits** **November 14, 1997**

nuisance.

The project is not within ¼-mile of a school. In addition, the new or modified permit unit does not have an increased cancer risk greater than, or equal to, one in a million (1x 10^{-6}) during a lifetime of 70 years or pose a risk of nuisance. See Rule 1401 rule evaluation for details.

This project is also not considered as a significant project due to the estimated overall criteria emission decrease. Rule 212(c)(2) states any new or modified facility which has on-site emission increases exceeding the daily maximum specified in subdivision (g) is subject to public notification. The District's Rule 212 Rule Implementation Guidance for Rule 212 Public Notices, December 19, 2006, specifies that for multiple application projects (1) the total emissions from all the project's applications shall be used to determine if the emission increases at the facility exceed any of the daily maximums in subdivision (g), and (2) include emissions reduction resulting from the modification of existing piece of equipment (i.e., curtailment of usage of Boilers 86-B-9000, 9001, and 9002) in determining if the emission thresholds exceeds that specified in subdivision (g). Therefore, the post modification emissions is compared to the pre-modification emissions to determine if the emission increases exceed the daily maximum thresholds listed in subdivision (g). The table below contains a comparison of pre-modification emissions for the three existing boilers (86-B-9000, 86-B-9001, and 86-B-9002) and the post-modification emissions (estimated controlled emissions for the Cogeneration Unit and curtailed boiler emissions) versus the emission increase threshold in Rule 212(g). As noted in the table, there is an overall project emission decrease of all the criteria pollutants.

Table 23. Rule 212 Emission Comparison

Air Contaminant	R212(g) Daily Maximum Threshold (lb/day)	Emission (lb/day)					Exceeds R212(g) Daily Maximum Threshold ?
		Pre-Mod[1]	Post-Mod			Overall Project/ Modified Facility[3]	
		Boilers B-9000, B-9001, B9002	Cogen-eration Unit[2]	Boilers B-9000, B-9001, B9002	Total		
CO	220	265	122	119	241	-24	No
NOx	40	207	131	29	160	-47	No
PM10	30	162	110	21	131	-31	No
SO2	60	161	44	47	91	-70	No
VOC	30	99	55	25	80	-20	No

Rule 212 | **Standards for Approving Permits** | **November 14, 1997**

Lead	3	0	0	0	0	0	No

1. Pre-Modification Emissions: The maximum daily emissions based on equipment rated capacity
2. Post-Modification Emissions for Cogeneration Unit: 30-day average maximum potential to emit under normal operation that yields the maximum emissions during non-commissioning. NOx and CO include normal operation with maximum shutdowns and startups. PM10, SO2, and VOC include normal operation without shutdowns and startups. See Appendix C and N. Note that Appendix C only includes the emissions due to combustion; Appendix N includes both combustion emissions and fugitive emissions and is reflected in Table 23.
3. Overall project consists of the new cogeneration unit and reduced operation of existing boilers 86-B-9000, 86-B-9001, and 86-B-9002. See Appendix N, Scenario 4: Cogen Unit operating at 100% maximum capacity and Boiler 86-B-9002 operating at 54% maximum capacity. Scenario 4 represents the greatest anticipated post-modification emissions and thus lowest overall project emission decrease.

Therefore, the project is not subject to the public noticing requirements in Rule 212 since (1) the new or modified permit units are not located within 1,000 feet of a school, (2) the new or modified facility does not have on-site emission increases exceeding any of the daily maximums specified in subdivision (g) but has an decrease instead, and (3) the new or modified permit units does not have an increased cancer risk greater than, or equal to, one in a million ($1x\ 10^{-6}$) during a lifetime of 70 years or pose a risk of nuisance.

Rule 218 | **Continuous Emission Monitoring** | **May 1, 1999**

The rule sets certification standards and QA/QC procedures for CEMS that are required by permit conditions and/or regulations with the following exceptions:

- CEMS subject to RECLAIM (Regulation XX); Regulation IX - “New Source Performance Standards (NSPS)”, Regulation X - National Emission Standards for Hazardous Air Pollutants (NESHAPS), or Regulation XXXI - "Acid Rain Program".
- CEMS subject to permit conditions where the purpose of the CEMS is to

Rule 218	**Continuous Emission Monitoring** **May 1, 1999**
	monitor the performance of the basic and/or control equipment and not to determine compliance with any applicable limit or standard. • CEMS where alternative performance specifications are required by another District rule. The new Cogeneration Unit will have a CO and a NOx CEMS on the exhaust stack. SO2 emissions will be monitored through continuous measurement of fuel flow of the natural gas and refinery gas and of the total sulfur concentrations of the fuel gas that is combusted in the duct burner. Only the CO CEMS is subject to the requirements of this regulation since the NOx and SO2 CEMS are subject to RECLAIM.
218(c)(1)	*CEMS Certification:* An applicant must choose one of the following options for certification, operation, and maintenance of a CEMS: • Certify the CEMS according to District Rule 218.1(b) and operate and maintain the CEMS according to Rule 218(b), (e), (f) and (g) and Rule 218.1(b) and (d), or, • Certify the CEMS according to 40CFR60 (NSPS) Appendix B - "Performance Specifications" and operate and maintain the CEMS according to Rule 218(b), (e), (f) and (g) and 40CFR60 Appendix F - "Quality Assurance Procedures" Ultramar chose to certify, operate, and maintain the subject CO CEMS on the existing boilers according to the second (NSPS) option. *Quality Assurance Procedures [40CFR60 Appendix F]:* Ultramar has been performing the required audits of their existing CO CEMS. Based on their history of compliance with this regulation for the existing CO CEMS, it is expected that Ultramar will comply with the specified certification and QA/QC requirements for the CO CEMS on the new Cogeneration.

Rule 401	**Visible Emissions** **November 9, 2001**
	This rule specifies that a person shall not discharge emissions from a source for a period or periods aggregating more than three minutes in any one hour which are as dark or darker in shade as that designated No. 1 on the Ringelmann Chart or

Rule 401	**Visible Emissions**	**November 9, 2001**
	emissions of such opacity that it obscures an observers view to an equal or greater level. This is equivalent to opacity of 20%. Visible emissions are not expected since the subject gas turbine will combust natural gas and the duct burner will combust a blend of refinery fuel gas and natural gas. Also, Ultramar has a long record of operating the three existing boiler units within the limits of this rule. Compliance with this regulation is expected.	

Rule 402	**Nuisance**	**May 7, 1976**
	This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. Nuisance is not expected since the subject cogeneration unit will combust natural gas and refinery fuel gas. Also, Ultramar has a long record of operating the three existing boilers without causing nuisance. Compliance with this regulation is expected.	

Rule 404	**Particulate Matter - Concentration**	**February 7, 1986**
	This rule sets concentration limits for total PM (solid and condensable) emissions. The rule limit varies based on the quantity of exhaust gas (dry basis) discharged from a source. <u>New Gas Turbine and Duct Burner</u> As specified in 404(c), the provisions of this rule do not apply to emissions resulting from the combustion of liquid or gaseous fuels in steam generators or gas turbines. Therefore, the gas turbine and duct burner are exempt from this rule. <u>Boilers 86-B-9000, 86-B-9001, and 86-B-9002</u> As noted above, Rule 404(c) states this rule shall not apply to emissions resulting	

Rule 404	**Particulate Matter - Concentration** **February 7, 1986**
	from the combustion of gaseous fuels in steam generators. The boilers combust refinery gas and generate steam. Therefore, Rule 404 does not apply to the boilers.

Rule 405	**Solid Particulate Matter - Weight** **February 7, 1986**
	This rule sets solid PM mass emission limits for the processing of solid materials. The rule is not applicable to combustion sources such as the subject gas turbine, duct burner, and boilers.

Rule 407 | **Liquid and Gaseous Air Contaminants** | **April 2, 1982**

This rule contains the following emission limits:

- Carbon monoxide (CO) - 2,000 ppmv (dry; 15 minute average) [407(a)(1)]
- Sulfur Compounds - 500 ppmv (calculated as SO_2; 15 minute average) [407(a)(2)(B)]

CO Limit

New Gas Turbine and Duct Burner

The new Cogeneration Unit and duct burner will be equipped with a CO catalyst and the permit will be conditioned with a CO emission limit of 4 ppmvd (15% O_2, 1-hr avg.). According to the turbine manufacturer, maximum CO emissions during start-up and shutdown are expected to be 25 and 200 ppmvd (15% O_2), respectively. Compliance with the 2000 ppmv CO limit is expected. A CO source test will be required to verify compliance.

Boilers 86-B-9000, 86-B-9001, and 86-B-9002

All three boilers have been source tested for CO. The source test results are as follows:

Table 24. CO Source Tests for Boilers since 2005

Boiler	Source Test Date	CO Concentration, ppmv	Compliance with Rule 407?

Rule 407 | **Liquid and Gaseous Air Contaminants** | **April 2, 1982**

86-B-9000	May 2, 2005	89.36	Yes
86-B-9001	June 2, 2008	20.6	Yes
86-B-9002	October 12, 2009	21.48	Yes

Boiler 86-B-9002 is conditioned with a CO emission limit of 50 ppmv (3% O2, 1-hr avg.). Boiler 86-B-9000 is subject to Rule 1146 and is therefore subject to the more stringent limit of 400 ppmv. Therefore, continued compliance with Rule 407 is expected. CO source tests will be required for all three boilers.

Sulfur Compound Limit

The sulfur limit of 500 ppmv does not apply to the existing boilers and new Cogeneration Unit since Rule 407(c)(1) states the sulfur limit of this rule shall not apply if the equipment is subject to source specific rules in Regulation IX.

Rule 409 | **Combustion Contaminants** | **August 7, 1981**

This rule contains limit on combustion contaminants from the combustion of fuel of 0.23 gram per cubic meter (0.1 grain per cubic foot) of flue gas (15 minute avg. at 12% CO2).

Two PM/PM10 source tests have been performed on Boiler 86-B-9002 since its installation in 2006. As seen on the following table, the measured PM emissions are less than the 0.1 gr/dscf limit of this rule.

Table 25. PM10 Source Test for Boiler 86-B-9002

Boiler	Source Test Date	Measured PM Emissions (gr/dscf)	Compliance with Rule 409?
86-B-9002	Dec 15, 2011	0.0179	Yes
86-B-9002	Dec 1, 2008	0.00464	Yes

With the large margin of compliance for the Boiler 86-B-9002, it is expected that the proposed new Cogeneration Unit and existing boilers will also comply with the PM emission limit of this rule. A source test will be required of the new Cogeneration Unit and all three boilers to determine compliance with Rule 409.

Rule 431.1	**Sulfur Content of Gaseous Fuels** **June 12, 1998**
	This rule is subsumed by RECLAIM [Rule 2001(j)] for SOx RECLAIM facilities such as the Ultramar.

Rule 474	**Fuel Burning Equipment – Oxides of Nitrogen** **December 4, 1981**
	This rule is subsumed by RECLAIM [Rule 2001(j)] for NOx RECLAIM facilities such as the Ultramar.

Rule 475	**Electric Power Generating Equipment** **August 7, 1978**
	This rule applies to power generating equipment rated greater than 10 MW installed after May 7, 1976. Rule 475(a)(3) specifies that the equipment must comply with: • PM mass emission limit of 11 lb/hr; or • PM concentration limit of 0.01 grains/dscf (at 3% oxygen, dry basis averaged over 15 consecutive minutes) Compliance is demonstrated if either the mass emission limit or the concentration limit is met. According the estimated emissions provided by the facility (Steady State Emission Computation, Rev. I, August 1, 2012, Worley Parsons), the PM mass emissions from the new cogeneration unit is 4.59 lbs/hr. A source test will be required of the new Cogeneration Unit to determine compliance with Rule 475.

Rule 476	**Steam Generating Equipment** **October 8, 1976**
	Rule 476 applies to equipment that is used to produce steam, have a heat input rating of greater than 50 MMBtu/hr, and were constructed after May 7, 1976. This rule has limits on NOx and combustion contaminants. The NOx limits of this rule are subsumed by RECLAIM per 2001(j). The combustion contaminant (PM) limits are the same as the Rule 475 limits.

Rule 476 **Steam Generating Equipment** **October 8, 1976**

New Cogeneration Unit

The new duct burner is subject to the requirements of this rule. As discussed for Rule 475, compliance of the new Cogeneration Unit with the PM limit is expected. A source test will be required of the new Cogeneration Unit to determine compliance with Rule 476.

Boiler 86-B-9000

Existing boiler 86-B-9000 is rated at 39 MMBtu/hr and, therefore, not subject to this rule.

Boilers 86-B-9001 and 86-B-9002

Existing boilers 86-B-9001 and 86-B-9002 are subject to the requirements of this rule. PM/PM10 source tests were performed on Boiler 86-B-9002 in 2008 and 2011. As seen on the following table, the measured PM emissions are less than the 0.01 gr/dscf and 11 lbs/hr limit of this rule.

Table 26. PM10 Source Test for Boiler 86-B-9002

Boiler	Source Test Date	Measured PM Emissions		Compliance with Rule 476?
		gr/dscf	lb/hr	
86-B-9002	Dec 15, 2011	0.0150	5.31	Yes
86-B-9002	Dec 1, 2008	0.00464	1.62	Yes

With the large margin of compliance for boiler 86-B-9002, it is expected that Boiler 86-B-9001 will also comply with the PM emission limit of this rule. Condition D29.x1 requires Boiler 86-B-9002 to be source tested.

Rule 1109 **Emission of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries** **August 5, 1988**

Ultramar is subject to the requirements of Regulation XX (RECLAIM), which

Rule 1109	**Emission of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries**	**August 5, 1988**
	supersedes the requirements of Rule 1109 per Rule 2001(j). Therefore, the duct Burner/HRSG and existing boilers are not subject to the requirements of Rule 1109.	

Rule 1134	**Emission of Oxides of Nitrogen from Stationary Gas Turbines**	**August 8, 1997**
	This rule is applicable to all existing stationary gas turbines, 0.3 megawatt (MW) and larger, as of August 4, 1989. It is not applicable to new gas turbines such as the proposed Cogeneration Unit. In addition, the requirements of this rule have been subsumed by RECLAIM per 2001(j).	

Rule 1135	**Emission of Oxides of Nitrogen from Electric Power Generating Systems**	**July 19, 1991**
	The proposed Cogeneration system is not subject to this regulation since it is not an "electric power generating systems" as defined at 1135(b)(10). Also, the requirements of this rule have been subsumed by RECLAIM per 2001(j).	

Rule 1146	**Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters**	**September 5, 2008**
	This rule applies to boilers, steam generators, and hot oil heaters of equal to or greater than 5 million Btu per hour with the exception of boilers and process heaters with a rated heat input capacity greater than 40 million Btu per hour that are used in petroleum refineries [Reference Rule 1146(b)(2)]. Therefore, Rule 1146 does not apply to the following combustion equipment which are greater than 40 million Btu per hour: • Boiler 86-B-9002 (245 million Btu per hour) • Boiler 86-B-9001 (127.8 million Btu per hour) • Duct Burner/HRSG (164.5 million Btu per hour)	

Rule 1146 — **Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters** — **September 5, 2008**

Boiler 86-B-9000

This boiler is subject to the CO requirements of the rule. The NOx related requirements of this rule have been subsumed by RECLAIM per 2001(j) for RECLAIM facilities. A source test was conducted on May 2, 2005 and March 6, 2006. As seen on the following table, the measured CO emissions are less than the 400 ppm limit of this rule.

Table 27. CO Source Test for Boiler 86-B-9000

Boiler	Source Test Date	Measured CO Emissions (ppm)	Compliance with Rule 1146?
86-B-9000	March 6, 2006	17.3	Yes
86-B-9000	May 2, 2005	89.36	Yes

Continued compliance with this rule is expected.

Rule 1173 — **Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants** — **December 6, 2002**

The proposed construction will add valves, flanges, pumps, pressure relief devices and drains that are subject to control of fugitive emissions. Ultramar has an approved Inspection and Maintenance (I&M) Program. Ultramar will include the new components into their I &M program.

REG XIII — **New Source Review** — **April 20, 2001**
Application Deem Complete Date: 2012

This rule allows the Executive Officer to deny a Permit to Construct for any new, modified or relocated source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia, unless BACT is used. This rule also requires modeling and offset (among other

REG XIII	**New Source Review** **April 20, 2001** **Application Deem Complete Date: 2012**
	requirements) if there is a net increase in any nonattainment air contaminants for any new or modified source. The definition of "Source" in Rule 1302(ao) is "any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. The South Coast Air Basin (SOCAB) is designated in attainment for CO, NOx and SOx. As specified in a Policy and Procedures memo from Mr. Mohsen Nazemi, Executive Officer for the District's Engineering and Compliance Office, CO is subject to only the BACT requirements. An evaluation must be performed for PM10, VOC, and ammonia for compliance with Reg XIII. NOx and SOx emissions from RECLAIM facilities are regulated under Regulation XX (RECLAIM). Therefore, New Source Review requirements for NOx and SOx are specified in Rule 2005. The proposed new construction of the Cogeneration Unit will cause an emission increase of CO, VOC, and PM. The emission increase due to the Cogeneration Unit is shown in Table 21. The following is a discussion of each requirement in NSR.
BACT: 1303(a)	Any new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia, must employ BACT for the new or relocated source or for the actual modification to an existing source. Per District policy, BACT is required for any increase in emissions that exceeds 1.0 lb per day on a maximum daily basis. BACT has been included in the design of the proposed project. BACT means the most stringent emission limitation or control technique which: (1) has been achieved in practice for such category or class of source; or (2) is contained in any State Implementation Plan (SIP) approved by the US EPA for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitations or control technique is not presently achievable; or (3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost effective as compared to measures as listed in the Air Quality Management Plan

REG XIII	**New Source Review**	**April 20, 2001 Application Deem Complete Date: 2012**

(AQMP) or rules adopted by the District Governing Board.

Fugitive emissions. The majority of fugitive components begin installed are in natural gas and refinery gas service. BACT for fugitive emission control is summarized below:

- **Valves:** Bellow-sealed valves are required with the following exemptions which must included in the approved I&M program,

  1. Heavy liquid service (i.e., streams with a vapor pressure <0.1 psia @ 100 ^{o}F (kerosene) based on the most volatile class present > 20% by volume)
  2. Control valve
  3. Instrument tubing application
  4. Applications requiring torsional valve stem motion
  5. Applications where valve failure could pose safety hazard (e.g., drain valves with valve stem in horizontal position)
  6. Retrofit/special applications with space limitation (special applications such as skid mounted standard packaged systems)
  7. Valves not commercially available

  Valves installed where Bellow-sealed valves are not available will be subject to a leak rate of less than 500 ppmv by EPA Method 21 and an approved I&M program.

- **Relief Valves:** All relief valves will be connected to a closed vent system or equipped with a rupture disc.

- **Process Drain:** Process drains will be equipped with p-traps or seal pots and included in the approved I&M program.

- **Pumps:** Pumps in light liquid service will be equipped with double or tandem seals vented to a closed system with a leak rate less than 1000 ppm by EPA Method 21 and included in an approved I&M program. Pumps in heavy liquid service will include single mechanical seals with a leak rate less than 1000 ppm by EPA Method 21 and included in an approved I&M program. Ultramar does not expect to install any pumps.

- **Flanges:** All flanges must meet ANSI/API standards and included in an approved I&M program.

REG XIII	**New Source Review** **April 20, 2001** **Application Deem Complete Date: 2012**

- **Compressors:** All compressors will be vented to a closed vent system. No new compressors are expected to be installed.

Existing Boilers 86-B-9000, 86-B-9001, 86-B-9002. The proposed permit condition changes do not cause an increase in the emission of any criteria pollutants for the existing boilers so BACT is not required. The following BACT was required and was implemented by Ultramar during original construction of these units:

Boiler 86-B-9000:

- NOx: Use of low-NOx burner.
- CO & VOC: Good combustion practice
- PM10/SOx: Use of refinery fuel gas that complies with the 160 ppmv H2S limit of NSPS Subpart J

Boiler 86-B-9001:

- NOx: Use of SCR.
- PM10/SOx: Use of refinery fuel gas that complies with the 160 ppmv H2S limit of NSPS Subpart J
- Ammonia: Ammonia slip concentration must be less than 20 ppmvd

Boiler 86-B-9002:

- NOx: Use of low-NOx burner and SCR. Permit conditioned with a stack gas NOx concentration limit of 9 ppmvd (hourly avg) and 7 ppmvd (monthly avg).
- CO: Permit conditioned with a stack gas CO concentration limit of 50 ppmvd
- PM10/SOx: Use of refinery fuel gas with a total sulfur concentration less than 100 ppmv
- Ammonia: Ammonia slip concentration must be less than 20 ppmvd

Both Boilers 86-B-9001 and 86-B-9002 are equipped with a certified CO and NOx CEMs to show continuous compliance with the stack gas CO and NOx concentration limits. The V-1000 fuel drum which supplies refinery fuel gas to the boilers is equipped with certified fuel sulfur gas chromatograph based semi-continuous emission monitoring systems to monitor TRS concentrations. Annual source tests are performed on the SCRs for Boilers 86-B-9001 and 86-B-9002 to demonstrate compliance the ammonia slip limit.

REG XIII **New Source Review** **April 20, 2001**

Application Deem Complete Date: 2012

New Cogeneration Unit - The proposed Cogeneration Unit is a new source with an increase in emissions of CO, NOx, PM10, SOx, VOC and NH3. It is subject to BACT for PM10, VOC, and NH3 under Rule 1303. Additionally, the source is subject to BACT for NOx and SOx under Rule 2005 and for CO, NOx and SOx under Regulation XVII. Ultramar has proposed the following BACT for the non-RECLAIM pollutants for the gas turbine, duct burner, and SCR:

Table 28. Ultramar's Proposed BACT for Non-RECLAIM Pollutants

A/N	Equipment	Proposed BACT*			
		CO	VOC	PM10	NH_3, Inorganic
527889	Gas Turbine + with HRSG/Duct Burner	4 ppmv dry corrected to 15% O2	3 ppmv dry corrected to 15% O2	Gas Turbine: Natural Gas HRSG/Duct Burner: Natural gas/Refinery gas	--
527888	SCR	--	--	--	5 ppmv

\+ Aeroderivative engine
* BACT limit are based on a 1-hour averaging time

See discussion under Rule 2005 for an analysis of BACT for NOx and SOx.

For major sources, BACT is determined at the time the Permit to Construct is issued, and is the Lowest Achievable Emission Rate (LAER) which has been achieved in practice. The BACT Guidelines for Cogeneration Units operating on natural gas and/or refinery gas are as follows for VOC, CO, PM_{10}, and NH_3:

Table 29 . Non-RECLAIM Pollutant BACT for Cogeneration Units

	Facility/ A/N	Gas Turbine Type	Fuel	CO	VOC	PM	NH3

REG XIII	**New Source Review**	**April 20, 2001** **Application Deem Complete Date: 2012**

Techno-logically Feasible	Chevron* A/N 470782	Frame	Natural Gas; Refinery Gas	2 ppmv	2 ppmv	Natural Gas; Refinery gas	5 ppmv
	Tesoro* A/N 484368	Frame	Natural Gas; Refinery Gas	2 ppmv	2 ppmv	Natural gas; Refinery gas	5 ppmv
	CPV Sentinel LLC+ A/Ns 472139, 472143, 472147, 472154, 472156, 472158	Aeroderi-vative	Natural Gas	4 ppmv	2 ppmv	Natural gas	5 ppmv
	Walnut Creek+ A/Ns 450894, 450895, 450896, 450897, 450898	Aeroderi-vative	Natural Gas	6 ppmv	2 ppmv	Natural gas	5 ppmv
Achieved in Practice	City of Riverside+ A/Ns 481647, 481649	Aeroderi-vative	Natural Gas	4 ppmv	2 ppmv	Natural gas	5 ppmv
	Canyon Power+ A/Ns 476651, 476656, 476659, 476661	Aeroderi-vative	Natural Gas	4 ppmv	2 ppmv	Natural gas	5 ppmv

REG XIII | **New Source Review** | **April 20, 2001**
Application Deem Complete Date: 2012

	City of Burbank* A/N 386305	Frame	Natural Gas	2 ppmv	2 ppmv	Natural gas	5 ppmv
	Vernon City Power* A/N 394164	Frame	Natural Gas	2 ppmv	2 ppmv	Natural gas	5 ppmv

* Combined Cycle
\+ Simple Cycle

Ultramar is proposing to install an aeroderivative engine. The Cogeneration Unit proposed is neither a combined cycle or simple cycle system, but rather a *combined heat and power type*, where there is a HRSG and duct burner to produce additional steam but no steam turbine to produce additional electricity.

A carbon monoxide (CO) oxidation catalyst for CO and VOC control is typically used in conjunction with the SCR. The CO oxidation catalyst oxidizes the CO and a portion of the VOC in the exhaust gas into carbon dioxide. The proposed CO oxidation catalyst is guaranteed to reduce the CO from 47 ppmvd to 4 ppmvd and the VOC from 4.9 ppmvd to 3 ppmvd, all at 15% O_2, except during start-up and shut-down events.

Ultramar's proposal of 4, 3, and 5 ppm for CO, VOC, and ammonia slip, respectively, is acceptable as BACT since the duct burner will burn refinery gas and natural gas while the other aeroderivative engines Achieved in Practice listed above operate only natural gas. Please see the discussion in Rule 2005 for NOx and SOx BACT levels. Therefore, the proposed control levels will meet the BACT requirements for CO, PM_{10}, and NH_3.

BACT limits and limits from prohibitory rules (e.g., Rule 409) will be imposed on the permit. In addition, source tests will be required for CO, PM, and NH_3 since this project is subject to BACT and the prohibitory rules.

1303(b)(1)

Modeling: The applicant must substantiate with modeling that the new facility or modification will not cause a violation, or make significantly worse an existing violation of any state or national ambient air quality standards at any receptor location in the District. According to 1306(b), the new total emissions for modified sources shall be calculated on a pound per day basis for determination

REG XIII	**New Source Review** **April 20, 2001** **Application Deem Complete Date: 2012**
	of BACT and modeling applicability. The modeling procedures are discussed in Appendix A of this rule. Appendix A of this rule specifies modeling is not required for VOC. Therefore, modeling is required for PM10 only. Additionally, modeling is required for NOx under Rule 2005. According to Appendix A of both Rule 1303 and Rule 2005, an applicant must either (1) provide an analysis approved by the Executive Officer or designee, or (2) show by using the Screening Analysis in Appendix A, that a significant change (increase) in air quality concentration will not occur at any receptor location for which the state or national ambient air quality standard for NOx or PM10 is exceeded. The NOx and PM10 screening thresholds for combustion sources up to 40 MMBtu/hr are contained in Table A-1 Rule 2005 and Rule 1303, respectively. Although this table only contains thresholds for combustion source up to 40 MMBtu/hr, an SCAQMD *Policies and Procedures* memo specifies that it can be assumed that a source rated at greater than 40 MMBtu/hr with emissions less than or equal to the allowable emissions levels specified in Table A-1 for a 40 MMBtu/hr source "will not cause a significant increase in an air quality concentration and no further modeling is required". The screening emission levels specified in Table A-1 for NOx and PM10 are 1.31 and 7.9 lb/hr, respectively. The maximum NOx and PM10 emissions for the proposed Cogeneration Unit during start-up, shutdown or normal operation are 10.2 lb/hr and 4.59 lb/hr, respectively. Modeling is not required for PM10 since the maximum PM10 emissions for the proposed Cogeneration Unit are less than the screening levels in Table A-1. Ultramar performed modeling for CO and PM10 even though it is not required. AQMD modeling staff reviewed the air quality modeling submitted by Ultramar. Modeling staff provided their comments in a memorandum from Mr. Philip Fine to Mr. Jay Chen dated October 17, 2012. A copy of this memorandum is contained in the engineering file. District modeling staff determined the AERMOD modeling generally conformed to the District's dispersion modeling procedures. Summary results of the modeling is as follows: • CO – Peak 1-hour and 8-hour CO impacts plus the worst case background concentrations are 3,469 µg/m3 and 2,994 µg/m3, respectively. These impacts are less than the state 1-hour and federal 8-hour CO standards of 23,000 µg/m3

REG XIII | **New Source Review** | **April 20, 2001**
Application Deem Complete Date: 2012

and 10,000 µg/m3, respectively.

- NO2 - Peak 1-hour and annual NO2 impacts plus the worst case background concentrations are 273.51 µg/m3 and 40.30 µg/m3, respectively. These impacts are less than the state 1-hour and annual NO2 standards of 339 µg/m3 and 57 µg/m3, respectively.
- SO2 - Peak 1-hour and 24-hour SO2 impacts plus the worst case background concentrations are 237.72 µg/m3 and 31.87 µg/m3, respectively. These impacts are less than the state 1-hour and 24-hour SO2 standards of 655 µg/m3 and 105 µg/m3, respectively.
- PM10 – Background PM10 air quality in the impact area exceeds the state 24-hour and annual PM10 standards; therefore, project increments are compared to the significance thresholds in Table A-2 of Rule 1303. The peak 24-hour and annual PM10 impacts are 0.74 µg/m3 and 0.16 µg/m3, which are less than the Rule 1202 significance thresholds of 2.5 µg/m3 and 1.0 µg/m3, respectively.

Table 30. Gas Turbine and HRSG/Duct Burner CO and PM_{10} Modeling Results

Criteria Pollutant	Averaging Period	Ambient Background Conc. (ug/m^3)	Calculated Conc. (ug/m^3)	Total Conc. (ug/m^3)	Most Stringent Air Quality Standard (ug/m^3)		Significant Change in Air Quality Conc. (ug/m^3)	Below Threshold ? Yes/No
					State	Federal		
CO	1-hr	3448.2*+	18.95	**3467.15**	**23000**	**40000**	1100	Yes
	8-hr	2988.44*+	3.36	**2992.52**	**10000**	**10000**	500	Yes
NO2	1-hr	245.44*	28.07	**273.51**	**339**		20	Yes
	1-hr	147.27+	28.07	**175.33**		**188**	20	Yes
	Annual	40.03*+	0.29	**40.30**	**57**	**100**	1	Yes
SO2	1-hr	289.2*	1.96	**237.72**	**655**		NA	Yes
	1-hr	55.21+	1.96	**56.31**		**655**	NA	Yes
	24-hr	31.55*+	0.57	**31.87**	**105**	**105**	NA	Yes
	Annual	7.1+	0.13	**5.86**		**80**	NA	Yes
PM10	24-hr	75*+	**0.71**	62.71	50	150	**2.5**	Yes
	Annual	30.5*+	**0.16**	30.66	20	NA	**1**	Yes

REG XIII | **New Source Review** | **April 20, 2001**

Application Deem Complete Date: 2012

PM2.5	24-hr	82.9*+	**0.71**	64.11	35	35	**2.5**	Yes
	Annual	14.6*+	**0.16**	14.36	12	15	**1**	Yes

* State ambient background concentration
\+ Federal ambient background concentration
Evaluation Criteria **Bolded**

Compliance with the modeling requirements of this rule is achieved.

1303(b)(2)

Offsets: The emission increase/decrease due to this project is shown in Table 31.

Table 31. Net Emissions for the Cogeneration Project

	Emissions (lb/day)				
	NOx	**CO**	**VOC**	**PM10**	**SO2**
New Cogeneration Unit: Gas Turbine & HRSG/Duct Burner (1)	131	122	55	110	44
Existing Boilers 86-B-9000, B-9001, B-9002 at Reduced Load (2)	29	119	25	21	47
Subtotal for Cogen Project	**160**	**241**	**80**	**131**	**91**
Existing Boilers 86-B-9000, B-9001, B-9002 (3)	-206.7	-265	-99	-162	-161
Net Emission	**-46**	**-24**	**-20**	**-31**	**-70**

(1) Based on Maximum Monthly Emissions/30 days, See Appendix N.
(2) Based on the boilers operating at highest projected load of 54% (133 mmBtu/hr) of Boiler 86-B-9002 for the total load (411.8 mmBtu/hr). See Appendix N, Scenario 4.
(3) Based on NSR emissions for the three boilers.

As noted in an email from Mr. Jay Chen, Senior AQ Engineering Manager of the District's Refinery and Waste Management Permitting, formation of a combined emission limit that includes a new or modified permit unit along with one or more existing permit units qualifies for the concurrent facility modification offset exemption at Rule 1304(c)(2) if the combined limit represents a reduction in maximum potential emissions calculated according to Rule 1303(d). A copy of

REG XIII	**New Source Review** **April 20, 2001** **Application Deem Complete Date: 2012**
	Mr. Chen's email is contained in the engineering file. The current combined maximum potential VOC and PM10 emissions in NSR for boilers 86-B-9000, B-9001, and B-9002 are based on the individual emission limits of 99 lbs/day and 162 lbs/day, respectively. To assure a reduction in combined maximum potential VOC and PM10 emissions of these existing permit units plus the proposed Cogeneration Unit, a permit condition that limits the combined VOC and PM10 emissions to 2,981 lbs/month (based on 98 lbs/day) and 4,897 lbs/month (based on 161 lbs/day); respectively, will be imposed on each of the permit units. This is one lb/day less than the current potential to emit limits for the three boilers. Therefore, the proposed Cogeneration Unit qualifies for the concurrent facility modification offset exemption so VOC and PM10 ERCs are not required. Offsets are not required for CO. On June 11, 2007, EPA re-designated the South Coast Air Basin (SCAB) as attainment with respect to CO National Ambient Air Quality Standards (NAAQS). Since AQMD was already attainment with State standards and NAAQS for the rest of basin, and CO is not identified as a precursor to any non-attainment pollutants in Regulation XIII, the requirements of Regulation XIII (Rule 1303) do not apply to any new or modified source with a net emission increase in CO. In accordance with Mohsen Nazemi's August 14, 2007 memo regarding PSD Delegation, no CO offsets will be required in the form of ERCs and no NSR codes from the Priority Reserve or Rule 1304 exemptions to offset emission increases for CO should be used for all new permits issued for equipment with CO emission increases. . Also according to Mr. Nazemi's memo, the District will continue to require CO BACT for combustion sources. CO BACT is an oxidation catalyst, which also acts as BACT for VOC. Since the District does not have any continuous monitoring systems or continuous monitoring requirements for VOC and since in most combustion processes VOC and CO emissions typically change in the same direction, the CO controls and CEMS should be used as a surrogate to have a better continuous accounting for VOC emissions. Therefore, the only exemptions under NSR for CO at this time should be for offsets and modeling.
1303(b)(3)	Sensitive Zone Requirements. The emission increases from this project are exempt from offsets per Rule 1304(c)(4). Therefore, ERCs are not required.
1303(b)(4)	Facility Compliance. This facility complies with all applicable District rules and

REG XIII	**New Source Review** **April 20, 2001** **Application Deem Complete Date: 2012**
	regulations.

1303(b)(5)

Major Polluting Facilities. This project is a major modification at a major polluting facility. Therefore, the facility shall comply with the following requirements.

(A) *Alternative Analysis. Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source.*

In lieu of conducting an alternative analysis, Ultramar will meet the requirements of this subparagraph with compliance with the California Environmental Quality Act (CEQA) in accordance with Rule 1303(b)(5)(D). See discussion under 1303(b)(5)(D).

(B) *Statewide Compliance. Demonstrate that all major sources in the state under control of the applicant are in compliance or on a schedule for compliance with all applicable federal emissions standards.*

Ultramar has certified that all major sources in the state under control of the applicant are in compliance with all applicable federal emissions standards. Ultramar (Valero, Inc.) currently operates 7 major facilities in the state. The status of these facilities relative to Clean Air Act requirements is summarized in the following table:

Table 32. Compliance Status of Valero Facilities Located in California

Valero California Facilities	Facility Location	Compliance Status
Benicia Refinery	Benicia	Currently in compliance
Benicia Asphalt Plant	Benicia	Currently in compliance
Wilmington Refinery	Wilmington	Currently in compliance
Wilmington Asphalt Plant	Wilmington	Currently in compliance
Marine Terminal	Wilmington	Currently in compliance
Wilmington Marine Tank Farm	Wilmington	Currently in compliance
Olympic Tank Farm	Wilmington	Currently in compliance

(C) *Protection of Visibility. Conduct a modeling analysis for plume visibility if*

REG XIII	**New Source Review** **April 20, 2001** **Application Deem Complete Date: 2012**
	the net emission increase from the new or modified source exceeds 15 tons/year of PM or 40 tons/year of NOx; and the location of the source is within specified distance from a Class I area. The net emission increase from the new source is approximately 20 tons/year of PM10 and 22 tons/year of NOx. However, the Ultramar refinery is not within the distance specified in Table C-1 of this rule of a Class I area. The refinery is more than 32 km from any Federal Class I Area. The nearest Federal Class I Area (San Gabriel Wilderness) is more than 65 km away, while the furthest Federal Class I Area (Joshua Tree Wilderness) is more than 170 km away. Therefore, a modeling analysis for plume visibility is not required for this project.
	(D) *Compliance Through California Environmental Quality Act.* The proposed project has been analyzed by a Negative Declaration document pursuant to Title 14 California Code of Regulations Section 15070. Therefore, the requirements of subparagraph (b)(5)(A) shall not apply to this project since the project was analyzed by a Negative Declaration document.
	Therefore, compliance of Rule 1303(b)(5) is expected.

Rule 1325	**Federal $PM_{2.5}$ New Source Review Program** **June 3, 2011** **Application Deem Complete Date: 2012**
	Applicability. This rule applies to any major modifications to a new major polluting facility, a major polluting facility, and any modification to an existing facility located in area designated as non-attainment for $PM_{2.5}$. With respect to major modifications, this rule applies on a pollutant-specific basis to those pollutants for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase. Rule 1325(b)(5)-MAJOR POLLUTING FACILITY means, on a pollutant specific basis, any emissions source located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit, 100 tons or more per year of $PM_{2.5}$, or its precursors. A facility is considered to be a major polluting facility only for the specific pollutant(s) with a potential to emit of 100

Rule 1325	**Federal $PM_{2.5}$ New Source Review Program**	**June 3, 2011** **Application Deem Complete Date: 2012**

tons or more per year.

Rule 1325(b)(13)-SIGNIFICANT means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

NOx: 40 tons/year

SOx: 40 tons/year

$PM_{2.5}$: 10 tons per year

For Calendar Years (CY) 2010 and 2011, Ultramar's facility-wide emissions and calculated emissions increase from the Cogeneration Unit for, NOx, SOx, $PM_{2.5}$ are as follows:

Table 33 - Rule 1325 Applicability

Pollutant	Reported Emissions (tons/year)		Emissions Increase from Cogen Unit	Significant Threshold	Subject to Rule 1325?
	CY 2010	CY 2011	(tons/year)	(tons/year)	
NOx	239	275	22	40	**No**
SOx	230	202	8	40	**No**
$PM_{2.5}$[1]	67	88	20	10	**No**

1. Assuming 100% of PM_{10} is $PM_{2.5}$ for combustion sources

Rule 1325 does not apply for any of the pollutants. Although the baseline NOx and SOx emissions are greater than 100 tons per year, the threshold for a major modification is 40 tons/year. The NOx and SOx emissions from the Cogeneration Unit are less than 40 tons/year (22 tons/year for NOx and 8 tons/year for SOx). Therefore, the modification is not considered a major modification for NOx and SOx. Since the baseline emission for $PM_{2.5}$ is less than 100 tons per year and the emission increase for $PM_{2.5}$ is less than 100 tons/year, the rule does not apply to this pollutant either.

Rule 1401	**New Source Review of Toxic Air Contaminants**	**May 3, 2002 Application Deem Complete Date: 2012**

Requirements **–** Rule 1401 contains the following requirements:

(d)(1) MICR and Cancer Burden - The cumulative increase in MICR which is the sum of the calculated MICR values for all toxic air contaminants emitted from the new, relocated or modified permit unit will not result in any of the following:

(A) an increased MICR greater than one in one million (1.0×10^{-6}) at any receptor location, if the permit unit is constructed without T-BACT;

(B) an increased MICR greater than ten in one million (1.0×10^{-5}) at any receptor location, if the permit unit is constructed with T-BACT;

(C) a cancer burden greater than 0.5.

(d)(2) Chronic Hazard Index - The cumulative increase in total chronic HI for any target organ system due to total emissions from the new, relocated or modified permit unit will not exceed 1.0 at any receptor location.

(d)(3) Acute Hazard Index - The cumulative increase in total acute HI for any target organ system due to total emissions from the new, relocated or modified permit unit will not exceed 1.0 at any receptor location.

Analysis **–** Under this rule, a health risk assessment (HRA) must be performed for each individual permit unit for which there is an increase in TACs. The applicant performed this risk assessment in accordance with the SCAQMD Risk Assessment Procedures for Rules 1401 and 212 Version 7.0 (July 2005) and the Consolidated Tables of OEHHA/ARB Approved Risk Assessment Health Values (February 2009). The HRA was performed using the CARB Hotspots Analysis Reporting Program (HARP) model (version 1.4a). The HARP model combines the US EPA Industrial Source Complex dispersion model with a risk calculation model based on the Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA, 2003). The dispersion portion of the HARP model provides estimates of source-specific annual and hourly maximum ambient groundlevel concentrations. The risk calculator in the HARP model estimates the cancer risk, chronic index, and acute index values. The Cogeneration Unit was modeled as a point source (Cogeneration stack) and an area source (fugitive emissions). The emissions of TACs for combustion were calculated using emission factors from the 2010 Annual Emissions Report for the HRSG and the Supplemental Instructions for Reporting Quadrennial Air Toxics Emissions for natural gas turbines. Fugitive emissions are based on the Correlation Equation of the

Rule 1401	**New Source Review of Toxic Air Contaminants** **May 3, 2002** **Application Deem Complete Date: 2012**

SCAQMD Guide of Fugitive Emissions Calculations (SCAQMD, 2003). Toxic pollutant emissions from the proposed Cogeneration Unit were estimated. The TAC emission estimates, which are shown in the Appendix M, are based on the maximum fuel consumption rate of 506.1 MMBTU/hr for the proposed turbine/duct burner. The TAC emission factors used in calculating the emissions were derived from source test performed for the refinery gas and natural gas burned at the refinery for purposes of AB2588. These factors are the same or more conservative (greater) than those reported in the facility's AB2588 report. The table below shows the source parameters used for model inputs:

Table 34. Health Risk Assessment Source Parameters

Name	UTME	UTMN	Release Height (ft)	Width (ft)	Length (ft)	Tempt (^oF)	Diameter (ft)	Velocity (ft/sec)
Cogen	385407	3738093	70			287	9	68.2
Cogen Fugitives	385400	3738070	6	60	150			

Based on air quality modeling and related assumptions, results show that the maximum incremental cancer risk (MICR) to the Maximum Exposed Individual Worker (MEIW) associated with the proposed project is **0.09 in a million** and to the Maximum Exposed Individual Resident (MEIR) was calculated to be **0.3 in a million**, which is below the Rule 1401 threshold limits of 1 in a million. The calculated Acute Hazard Index (HIA) was **0.0018**, less than the rule limit of 1.0. Additionally, the Chronic Hazard Index (HIC) was **0.0054**, also less than the rule limit of 1.0.

Table 35. Health Risk Assessment Results

	Maximum Individual Cancer Risk (MICR)		**Chronic Hazard Index (HIC)**	**Acute Hazard Index (HIA)**
	MEIW	**MEIR**		
Project	0.09×10^{-6}	0.3×10^{-6}	0.0054	0.0018
Rule 1401	1×10^{-6}	1×10^{-6}	1.0	1.0
Comply?	Yes	Yes	Yes	Yes

MEIR: Maximum Exposed Individual Resident
MEIW: Maximum Exposed Individual Worker

Rule 1401	**New Source Review of Toxic Air Contaminants**	**May 3, 2002 Application Deem Complete Date: 2012**

AQMD modeling staff reviewed the applicant's analyses for Rule 1401. Modeling staff provided their comments in a memorandum from Mr. Phillip Fine to Mr. Jay Chen dated October 17, 2012. A copy of this memorandum is contained in the engineering file. The memorandum states that the HRA as performed by the applicant conforms to the District's applicable requirements. No significant deficiencies in methodology were noted.

Hazard Identification

A total of 51 AB2588 toxic air contaminants were evaluated for inclusion in the HRA (see Appendix M), 33 of which are chemicals listed in Appendix I of the SCAQMD Rule 1401 Guidelines, 20 are considered carcinogens, 23 are considered to have adverse chronic health effects, and 13 are considered to have adverse acute health effect.

Conclusion

The cancer risk for the TACs emitted from the Cogeneration Unit is below the significance threshold of one per million and chronic and acute indices are below the 1.0 threshold established under Rule 2401. Therefore, the Rule 1401 cancer risk and hazard index thresholds are not expected to be exceeded at any receptor location. No further health risk analyses are required.

Federal New Source Review for Toxics. Pursuant to Section 112(g) of the federal Clean Air Act (CAA), no person shall begin construction of a major stationary source emitting hazardous air pollutants listed in Section 112(b) of the CAA, unless the source is constructed with T-BACT and complies with all other applicable requirements, including definitions and public noticing unless the source is subject to an existing National Emission Standard for Hazardous Air Pollutants (NESHAP). The sources in the refinery are subject 40CFR Part 63, Subpart CC – National Emission Standard for Hazardous Air Pollutants from Petroleum Refineries. Therefore, the requirements of Federal New Source Review for Toxics will not apply.

Regulation XVII	**Prevention of Significant Deterioration (PSD)**	**August 13, 1999**

The PSD program is the federal New Source Review (NSR) program for

Regulation XVII	**Prevention of Significant Deterioration (PSD)** **August 13, 1999**
	pollutants for which an area is in attainment with or unclassified with respect to a National Ambient Air Quality Standard (NAAQS). As discussed earlier, SOCAB is currently designated as attainment with NAAQSs for SO2, NO2, CO, and lead. AQMD and EPA have signed a "Partial PSD Delegation Agreement". According to a memo from Mr. Mohsen Nazemi, Executive Officer of the Engineering and Compliance Division, this Partial Delegation Agreement is "intended to delegate the authority and responsibility to AQMD for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not set forth in AQMD Regulation XVII." This regulation was originally adopted in 1988. The permits to construct for construction Boilers 86-B-9001 and 86-B-9000 were issued before 1988 so they were not subject to this regulation for original construction. They have also not been subject to this regulation for any subsequent permitting. The permit to construct for Boiler 86-B-9002 was issued in 2004. At the time the Permit to Construct was issued to 86-B-9002, EPA revoked and rescinded the District's authority to implement the PSD program for issuing and modifying federal permits for new major sources of attainment pollutants. As a result, the District was not able to implement the PSD program.
Rule 1703	**PSD Analysis** This regulation specifies that the District shall deny any permits to construct unless: 1) Each permit unit complies with all applicable rules and regulations of the District; 2) Each permit unit is constructed with BACT for each criteria air pollutant with a net emission increase; and 3) Each permit unit with a significant emission increase of an attainment air pollutant complies with the requirements of 1703(a)(3).
1703(a)(1)	**Compliance with Applicable Rules and Regulations –** As addressed elsewhere in this evaluation, compliance with applicable rules and regulations is expected.
1703(a)(2)	**Best Available Control Technology –** As discussed above, Boilers 86-B-9001 and 86-B-9000 were issued before 1988 were constructed prior to the adoption of this regulation in 1988 so they were not subject to BACT requirements under this regulation. However, they were subject to BACT under Regulation XIII. Boiler

Regulation XVII	**Prevention of Significant Deterioration (PSD)** **August 13, 1999**
	86-B-9002 should have been subject to BACT for NOx and SOx under this regulation but not to BACT for CO since the SOCAB was non-attainment for CO in 1995 when the 86-B-9002 was constructed. Nevertheless, as discussed in the evaluation of Rule 1303 and 2005, existing boiler 86-B-9002 was constructed with BACT for CO, NOx, and SOx. As discussed in the evaluation of Rule 1303 and 2005, the proposed Cogeneration Unit is subject to BACT for CO, NOx and SOx under this regulation and will be constructed with BACT for CO, NOx and SOx.
1703(a)(3)	**Significant Emission Increase –** The requirements under 1703(a)(3), which are specified below, are applicable for each significant emission increase of an attainment air contaminant at a major stationary source. A comparison of the estimated maximum CO, NOx and SOx emissions for the proposed Cogeneration Unit (in a non-commissioning year) versus the significance thresholds of the regulation is contained in the table below.

Table 35. PSD Emissions

Pollutant	Emission Increase (ton/yr)	Significance Threshold (ton/yr)	Significant Increase of Attainment Pollutant?
CO	20	100	**No**
NOx	22	40	**No**
SOx	8	40	**No**

As seen in the table, the proposed Cogeneration Unit will not cause a significant emission increase of any attainment air contaminant. Therefore, the requirements of this section are not applicable. The permit for the Cogeneration Unit will be conditioned with pollutant concentration limits and equipment operational limits that will assure that maximum CO, NOx and SOx emissions do not exceed the estimated levels. The permit will include stack gas CO and NOx concentration limits of 4 ppmv and 2.5 ppmv, respectively. The fuel to the duct burner will be limited to a sulfur limit of 40 ppmv (1-hr average). CO and NOx emissions during startups and shutdowns are limited through permit conditions that limit startups and shutdowns to 20 hours per year to a maximum duration of 1 hour per startup and 30 minutes per shutdown.

1703(a)(3)(A)	***Certification of Compliance with Federally Enforceable Emission Limits and***

Regulation XVII	**Prevention of Significant Deterioration (PSD)** **August 13, 1999**
	Standards: Applicant certifies in writing, prior to the issuance of the permit, that the subject stationary source shall meet all applicable limitations and standards under the Clean Air Act (42 U.S.C. 7401, et seq.) and all applicable emission limitations and standards which are part of the State Implementation Plan approved by the Environmental Protection Agency or is on a compliance schedule approved by appropriate federal, state, or District officials. *Not Applicable*
1703(a)(3)(C)	***Modeling:*** Applicant must substantiate by modeling that the proposed source or modification, in conjunction with all other applicable emission increases or reductions (including secondary emissions) affecting the impact area, will not cause or contribute to a violation of: (i) Any National or State Ambient Air Quality Standard in any air quality control region; or (ii) Any applicable maximum allowable increase over the baseline concentration in any area. *Not Applicable*
1703(a)(3)(D)	***Ambient Air Quality Analysis:*** Applicant must conduct an analysis of the ambient air quality in the impact area the new or modified stationary source would affect. The analysis shall include one year of continuous ambient air quality monitoring, preceding the receipt of a complete application. With respect to any such contaminant for which no National Ambient Air Quality Standard exists, the analysis shall contain such air quality monitoring data as the Executive Officer determines is necessary to assess ambient air quality for that contaminant in any area that the emissions of that contaminant would affect. *Not Applicable*
1703(a)(3)(E)	***Analysis of the Impairment to Visibility, Soil, and Vegetation***: Applicant must provide an analysis of the impairment to visibility, soil, and vegetation that would occur as a result of the new or modified stationary source and the air quality impact projected for the baseline area as a result of general commercial, residential, industrial, and other growth associated with the source. *Not Applicable*
1703(a)(3)(F)	***Notice to EPA and FLM:*** The district must send a copy of the complete application (within 10 days after being deemed complete) to the EPA, the Federal Land Manager for any Class I area located within 100 km of the source, and to the federal official charged with direct responsibility for management of any lands within the Class I area. The District shall also send a copy of the preliminary decision, the District's analysis, and notice of any action taken to the above agencies. The analysis shall include a determination on the impact on

Regulation XVII	**Prevention of Significant Deterioration (PSD)** **August 13, 1999**
	visibility due to the project. *Not Applicable*
1714	**Prevention Of Significant Deterioration For Greenhouse Gases**. This rule sets forth preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. District Rule 1714 was SIP-approved by the EPA on January 9, 2013. Therefore, the District is delegated the authority and responsibility to review and issue the PSD permit for GHGs.

Based on the U.S. EPA PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011), the Cogen Unit is subject to a PSD permit. The refinery applied the flow chart in Appendix B from the March 2011 Guidance document as the rationale for applicability and is presented in Table 36.

Table 36
Applicability Determination for GHG PSD

Step	**Action**	**Result**
Step 1	Will the permit be issued on or after July 1, 2011?	Yes
Step 2	Determine the new source's PTE in tons per year (TPY) for each of the 6 GHG pollutants taking into account enforceable limits.	See Table 34
Step 3	Calculate the GHG emissions on a CO2eq basis using the global warming potential factors applied to the mass of each of the 6 GHG pollutants.	See Table 34
Step 4	Are the potential GHG emissions on a CO2eq basis equal to or greater than 100,000 TPY?	**Yes**
Step 5	Calculate the total GHG emissions on a mass basis.	See Table 34
Step 6	Are the potential GHG emissions on a mass basis less than 250 TPY (100 TPY if the new source is in a listed category)?	No
		GHG emissions are subject to PSD as part of this permit review.

Source: U.S. EPA PSD and Title V Permitting Guidance for Greenhouse Gases, Appendix B, pages B-1 and B-2, March 2011.

The GHG emissions associated with the Cogen Unit are shown in the Table 37. The emissions of 274,040.6 tons/yr CO_2eq and 273,908.4 tons/yr GHG (mass basis) meet the requirement for a GHG PSD permit since both are greater than the 100,000 short tons/yr CO_2eq emissions and 100 tons/yr GHG, respectively.

Table 37
Cogen Unit GHG Emissions Estimates

Cogen	Duty (mmbtu /hr)	Hours per Year	CO2 (kg/ mmbtu)	CH4 (g/ mmbtu)	N2O (g/ mmbtu)	CO2 (tonnes/ yr)	CH4 (tonnes/ yr)	N2O (tonnes /yr)	CO2eq (tonnes/ yr)
Turbine	341.6	8760	53.02	1.00	0.10	158657.9	3.0	0.0	158735.1
HRSG	164.5	8760	62.33*	1.00	0.10	89825.7	1.4	0.1	89872.9
Total (tonnes/yr)						248,483.6	4.4	0.1	248,608.0
Total (short tons/yr)						273,903.5	4.9	0.1	274,040.6
Total GHG- Mass Basis (CO2 + N2O + CH4) (short tons/yr)						273,908.4			

* Based on CO2 emission factor for refinery gas; The HRSG will actually burn a mixture of natural gas and refinery gas to meet the 40 ppm SOx BACT limit for refinery gas. Therefore, the CO2 emission factor for the HRSG should actually be less than 62.33 kg/mmBtu. In addition, according to the refinery, the CO2 emission factor for refinery gas changes due to the changes in operation such as the type of crude they receive and process.

Per EPA's GHG permitting guidance document, BACT is the only GHG PSD analysis required. Ultramar used U.S. EPA's top-down BACT approach in their GHG BACT Analysis.

STEP 1

Step 1 calls for the identification of all available control technology. The technologies available to reduce GHG emissions include (1) add-on controls; (2) alternative generating /renewable energy technologies; (3) carbon capture/sequestration; (4) use of an alternative fuel to that proposed; (5) energy efficiency; and, (6) inherently lower-emitting GHG processes. Some common technology types are discussed below to show their feasibility and infeasibility.

Add-on controls (Technology 1) To date, flue gas scrubber (amine-based solvent systems) have not been tested on natural gas power generating facilities. Therefore, no add-on controls are available at this time.

Renewable energy projects (Technology 2), such as solar and wind energy, are not feasible for the facility due to lack of space for sufficient solar panels and the demand for consistent power 24-hours a day and during low-wind conditions.

Regulation XVII	**Prevention of Significant Deterioration (PSD)**	**August 13, 1999**

Geothermal power requires thermal vents and strata which are not present in the area. Hydroelectric power requires a flowing river or a series of reservoirs to store water. While the mouth of the San Gabriel River is approximately 1 mile east of the facility, it is channelized and in a highly developed area. Therefore, it is not feasible to produce hydroelectricity in the vicinity of the Refinery.

Carbon Capture/Sequestration systems (Technology 3) have not yet been demonstrated on cogeneration equipment. Additionally, Ultramar does not have a system for transporting captured CO_2 or an available sequestration location. Therefore, it is not feasible to consider the use of carbon capture/sequestration.

Use Alternative Fuel to that Proposed (Technology 4) - The Cogen Unit power generating section is natural-gas fired, which is a clean fuel. Natural gas is currently used and readily available at the refinery. Therefore, it is the preferred fuel for the Cogen Unit. Other fuels, such as biomass, are required in large quantities and not readily available in the vicinity of the refinery.

Energy Efficiency (Technology 5) - The California Air Pollution Control Officer's Association has and continues to consider cogeneration as a preferred method for minimizing and mitigating GHG emissions. Improving energy efficiency is the primary method of reducing GHG emissions. The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) have established an emissions performance standard (EPS) for generation of electricity of 1,100 lbs CO_2e/MW-hr. To evaluate compliance with the standard, the electrical and thermal output of the Cogen Unit was calculated and compared to the EPS. As shown in Table 38, the EPS for the Cogen Unit is 585.1 lbs CO_2e/MWhr, which is well below the CPUC and CEC established EPS of 1,100 lbs CO_2e/MW-hr.

Table 38
Energy Efficiency Demonstration

Cogen Unit CO_2e Emissions (lbs/hr)				68,966.88
Electrical Output (MW-hr)				34.97
Thermal Output				
Stream	Flow (lb)	Enthalpy (Btu/lb)	Thermal Output (Btu)	Thermal Output (MW-hr)

HP Steam	257,412	1,298.4	334,225,397	97.9
LP Steam	415	1,181.9	490,914	0.1
Feedwater	260,001	194.2	-50,487,788	-14.8
Boiler BD	2, 589	422.7	-1,094,156	-0.3
Thermal Output Total			283,134,367	82.9
Energy Efficiency(1)				585.1

(1) Energy Efficiency = CO_2e Emissions/ (Electrical Output + Thermal Output)

Use Inherently Lower-Emitting GHG Processes, Practices, Designs, or a Combination of These The Cogeneration Unit (Technology 6) would allow the refinery to reduce usage of the existing boilers. As boilers are less efficient at producing steam, the Cogen Unit will improve energy efficiency for steam produced at the Refinery. Additionally, by installing the Cogen Unit, Ultramar will be reducing the demand for LADWP-supplied power. LADWP's main method of power production, 39%, is from coal-fired power plants (https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/ap-factandfigures). Coal produces approximately 78 percent more CO2 emissions per mmBtu than natural gas (Title 17, California Code of Regulations, Article 2, Appendix A, Table 4). Secondarily, reducing the steam demand on the boilers at the refinery by producing steam from the Cogen Unit will improve the energy efficiency of steam production, thereby further reducing GHG emissions. Therefore, the installation of the Cogen Unit achieves the lowest GHG emissions available to produce electricity and steam at the refinery.

STEP 2

Step 2 calls for elimination of technically infeasible options. Technologies 1 through 4 above are considered technically infeasible based on the analysis given above.

STEP 3

Step 3 calls for the remaining control technologies to be listed in the order of overall control effectiveness. Of the six control technologies, Technologies 5 and 6 - (Energy Efficiency; and, Use Inherently Lower-Emitting GHG Processes, Practices, Designs, or a Combination of These; respectively) are the remaining viable GHG control technologies. The objectives of the proposed project, when combined with the existing boiler usage being reduced, are designed (Technology 6) to improve energy efficiency (Technology 5) and thus reduce GHG emissions. Therefore, Ultramar determined no ranking is necessary.

Regulation XVII	**Prevention of Significant Deterioration (PSD)** **August 13, 1999**
	STEP 4 *Step 4* of the top-down approach requires consideration of economic, energy, and environmental impacts. Ultramar evaluated the cogeneration equipment on the market to identify the most appropriately sized unit to meet the needs of the Refinery. The Refinery power demand, 35 MW, is at a range where the options for different cogeneration units are very limited. Manufacturers of cogeneration units focus on small power demands, typically less than 25 MW, and large power demands, greater than 50 MW. At 35MW, Ultramar was limited to two options: (1) the GE LM2500 +G4 proposed in the project and (2) using two smaller units in parallel. The two smaller unit option was evaluated and determined to produce greater emissions based on published information. Therefore, it was determined that the proposed GE LM2500 +G4 is the preferred unit. The options chosen for the unit provide the best energy efficiency and emissions profile possible for the proposed project. The Cogen Unit will be 69.3% thermally efficient on an average day (70 degree day) when adjusted for steam production. Any parasitic loss from post-combustion control technology will reduce the thermal efficiency of the Cogen Unit, which increases the amount of GHG generated per unit of fuel burned. There are currently no feasible technologies to control GHG emissions for cogeneration plants, only technology to improve thermal efficiency. The HRSG increases the thermal efficiency of the Cogen Unit from 37.7% to 69.3% by using the "waste" heat from the exhaust and converting it to steam for the Refinery. Additionally, the HRSG will be equipped with an economizer to increase its thermal efficiency. An important consideration when designing the Cogen Unit is the overall refinery design. The Ultramar refinery is the newest refinery in Southern California, constructed in 1969 and, as such, is designed to be as efficient as possible. Based on the 2010 Solomon benchmarking survey, the refinery ranked second out of 80 U.S. refineries, first in 12 similar sized refineries, and first out of 18 western U.S. refineries. These rankings demonstrate that the refinery is one of the most energy efficient refineries in the country. During the project design, low energy equipment will be incorporated to keep operational costs to a minimum. Therefore, the technology chosen and the process design achieve the most efficient system in terms of GHG emissions for the proposed project. **Step 5** *Step 5* of the top-down approach requires selecting the most effective control option not eliminated in Step 4. As indicated above, the proposed BACT for the

Regulation XVII	**Prevention of Significant Deterioration (PSD)** **August 13, 1999**
	gas turbine/HRSG is as follows: 1. Use of combustion turbine technology coupled with modern duct firing technology in the HRSG 2. Use of a combination of clean fuels, i.e., natural gas and refinery gas, which meet the regulations of the South Coast AQMD, as specified in the project design criteria. 3. Use of good combustion practices in both the turbine and duct fired HRSG. 4. Periodic inspection and proper maintenance of the turbine and duct fired HRSG to maintain the combustion equipment in a condition which reflects the most efficient operation, i.e., efficient fuel combustion versus power output and steam production, accounting for system age and degradation effects. 5. Maintain compliance with the Emission Performance Standard (Title 20, California Code of Regulations, section 2900). 6. Monitor and report the net energy output on a calendar year basis. The only option remaining for the project is the GE LM2500 +G4, which is considered GHG BACT for the proposed project **Step 6** *Step 6,* which requires the use of inherently lower-emitting GHG processes, practices, designs, or a combination of these has been discussed in Step 4. Based on the above analysis, the project complies with the requirements for PSD for GHGs.

Rule 2005	**New Source Review for RECLAIM** **April 20, 2001** **Application Deem Complete Date: 2012**
2005(c)	Ultramar is a Cycle 1 NOx and SOx RECLAIM facility. Sources that are subject to RECLAIM must comply with the New Source Review requirements of Rule 2005 instead of Regulation XIII. A permit to construct cannot be approved for installation of a new source or modification of an existing source that results in an

Rule 2005	**New Source Review for RECLAIM** **April 20, 2001** **Application Deem Complete Date: 2012**
	emission increase of NOx or SOx at an existing RECLAIM unless the following requirements are met: • Best Available Control Technology (BACT) is applied to the source [2005(c)(1)(A)] • The operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A [2005(c)(1)(B)], and • The applicant demonstrates that the facility holds sufficient RECLAIM Trading Credits to offset the annual emission increase for the first year of operation at a 1-to-1 ratio [2005(c)(2)]. The new construction proposed in this project will cause an emission increase of SOx and NOx. Based on the maximum rating of the combustion equipment to be installed and the NOx and SOx BACT limits proposed, the NOx and SOx emission increase from this project is 41,409 lbs/year and 15,943 lbs/year, respectively, in a non-commissioning year. The emission increase due to the installation of the Cogeneration Unit is shown in Table 20. The following is a discussion of each applicable requirement in NSR for RECLAIM to this project.
2005(c)(1)	BACT. The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source or modification of an existing source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that BACT will be applied to the source. BACT for CO, PM10, and VOC is discussed is the evaluation of Rule 1303 for the existing boilers and the new proposed Cogeneration Unit. Rule 2001(c)(9) defines BACT as the most stringent emission limitation or control technique which: (A) has been achieved in practice for such category or class of source; or (B) is contained in any state implementation plan (SIP) approved by the Environmental Protection Agency (EPA) for such category or class of source; or (C) is any other emission limitation or control technique, including process and equipment changes of basic or control equipment which is technologically feasible for such class or category of source or for a specific source, and

Rule 2005	**New Source Review for RECLAIM**	**April 20, 2001 Application Deem Complete Date: 2012**

cost-effective as compared to AQMP measures or adopted District rules.

BACT shall be at least as stringent as Standards of Performance for New Stationary Sources (40 CFR Part 60). BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate (LAER) as defined in the federal Clean Air Act Section 171(3) [42 U.S.C. Section 7501(3)]. For practical purposes, nearly all AQMD LAER determinations will be based on AIP LAER because it is generally more stringent than LAER based on SIP, and because state law constrains the District from using the third approach.

An emission limit or control technology may be considered achieved in practice for a category or class of source if it exists in any of the following regulatory documents or programs: AQMD BACT Guidelines, CAPCOA BACT Clearinghouse, USEPA RACT/BACT/LAER Clearinghouse, other districts' and states' BACT Guidelines, and BACT/LAER requirements in New Source Review permits issued by AQMD or other agencies. In addition to the aforementioned means of being determined as AIP, a control technology or emission limit may also be considered as AIP if it meets all of the following criteria: commercial availability, reliability, and effectiveness.

Ultramar has proposed the following NOx and SOx BACT limits:

Table 39. Ultramar's Proposed BACT for RECLAIM Pollutants

Equipment	**Fuel**	**Proposed BACT***	
		NOx	**SOx**
Gas Turbine + with HRSG/ Duct Burner	Gas Turbine: Natural Gas HRSG/ Duct Burner: Natural Gas/ Refinery Gas	2.5 ppmv dry corrected to 15% O_2	Natural Gas with sulfur content < 1 grain/100 scf (16 ppm) regulated by the Public Utility Commission (PUC) Refinery Fuel Gas with total sulfur, calculated as H2S ≤ 40 ppmv; Natural Gas regulated by the Public Utility Commission

Rule 2005	**New Source Review for RECLAIM**	**April 20, 2001 Application Deem Complete Date: 2012**

			(PUC); or Combination of Refinery Fuel Gas and Natural Gas to meet total sulfur, calculated as H2S ≤ 40 ppmv, 1-hr avg

+ Aeroderivative engine
* BACT limit are based on a 1-hour averaging time

For major sources, BACT is determined at the time the Permit to Construct is issued, and is the LAER which has been achieved in practice. The BACT Guidelines for Cogeneration Units operating on both natural gas and refinery gas are as follows for NOx and SOx:

Table 40. RECLAIM Pollutant BACT Guidelines for Cogeneration Units

	Facility/ A/N	**Gas Turbine Type**	**Fuel**	**NOx**	**SOx**
Techno-logically Feasible	Chevron A/N 470782	Frame	Natural Gas; Refinery Gas	2 ppmv	Natural gas w/ S content ≤ 1 grain/100 scf; Refinery fuel gas w/ total sulfur ≤ 40 ppmv, 1-hr avg. & 30 ppmv, 24-hr rolling avg.
	Tesoro A/N 484368	Frame	Natural Gas; Refinery Gas	2 ppmv[1] 2.5 ppmv [2]	Natural gas w/ S content ≤ 1 grain/100 scf; Refinery fuel gas[3] w/ total sulfur ≤ 40 ppmv, 1-hr avg.
	CPV Sentinel	Aeroderi-vative	Natural Gas	2.5 ppmv	Natural gas

	LLC A/Ns 472139, 472143, 472147, 472154, 472156, 472158				
	Walnut Creek A/Ns 450894, 450895, 450896, 450897, 450898	Aeroderi-vative	Natural Gas	2.5 ppmv	Natural gas
Achieved in Practice	City of Riverside A/Ns 481647, 481649	Aeroderi-vative	Natural Gas	4 ppmv	Natural gas
	Canyon Power A/Ns 476651, 476656, 476659, 476661	Aeroderi-vative	Natural Gas	4 ppmv	Natural gas
	City of Burbank A/N 386305	Frame	Natural Gas	2 ppmv	Natural gas
	Vernon City Power A/N 394164	Frame	Natural Gas	2 ppmv	Natural gas

1. Natural gas fired cogeneration
2. Refinery fuel gas fired cogeneration; Refinery fuel gas is defined as a mixture of refinery gas, produced within the refinery, and natural gas obtained from a utility

regulated by the PUC.
3. Refinery fuel gas is defined as a mixture of refinery gas, produced within the refinery, and natural gas obtained from a utility regulated by the PUC.

Ultramar is proposing to install an aeroderivative engine although frame engines can achieve lower NOx emissions. Below is a discussion on why an aeroderivative engine was chosen over a frame engine.

Power Demand
Ultramar chose to install an aeroderivative engine based on their power demand. The refinery's power demand is approximately 32 MW. The annual energy usage for the refinery for the past two years is as follows:

Year	Purchased Power (MW)	3rd Party Generated (MW)	Total Power (MW)
2010	27.470	13.060	40.530
2011	25.850	13.380	39.230

Aeroderivative units are sized to produce 13 to 100 MW. Frame engines are sized to produce 43 megawatts (MW) and up. Using a frame unit at Ultramar would be at approximately 75 percent of the operational design of the engine. As a result, the LM2500 series (34 MW) operates in the power range desired by Ultramar.

Design Differences
Information regarding the differences between frame and aeroderivative units was requested from General Electric. Aeroderivative and frame gas turbines have evolved with different design philosophies. Aeroderivative gas turbines have been derived from flight engines and are optimized for high simple-cycle applications while providing operational flexibility such as in peaking power, while maintaining high efficiency. Frame gas turbines in general have been designed for higher combined-cycle efficiencies and consequently operate at lower pressure ratios and lower simple-cycle efficiency than aeroderivative gas turbines. Since frame gas turbines have been designed for land-based applications, they are typically heavier and also have lower output per unit mass flow of air than aeroderivative gas turbines. Aeroderivative engines also have higher operating pressure ratios (OPR 28-30). The higher pressure-ratios result in a greater pressure drop and consequently greater temperature drop across the

turbines. Thus, while the firing temperatures of the aeroderivative engines are on the same order of magnitude as the frame engines, the higher temperature drop results in a lower exhaust temperature for these engines. These unique features result in superior simple-cycle efficiency (40-44%) with operational flexibility (10 minute start, 30 MW per minute ramp rate).

The SCR vendor, Deltak, LLC, for Ultramar's Cogeneration Unit provided a published paper, "Application of CER and CO Catalyst Systems to Simple Cycle Combustion Gas Turbines (2003)", which stated frame units at full power output produce between 9 and 15 ppm NOx emissions and CO emissions between 9 and 25 ppm. Aeroderivative units at full power output produce 25 ppm NOx and 20 to 60 ppm CO emissions. Emission control using SCR typically reduce NOx emissions 80 to 90 percent, with a lowest achievable emission of 2 or 3 ppm with low (5 ppm) ammonia slip. As such, for frame units that emit 9 ppm NOx, the reduction would only be 77 percent to achieve 2 ppm NOx at the exit, but for units that emit 15 ppm NOx, the reduction would be about 86 percent to achieve 2 ppm NOx at the exit. Ultramar has proposed a higher NOx reduction efficiency of 90 percent. At 90 percent NOx reduction efficiency, an aeroderivative unit emitting 25 ppm NOx would achieve 2.5 ppm NOx emissions at the exit.

Top-Down BACT Analysis

Major polluting facilities such as Ultramar are subject to LAER, which requires a top-down analysis to identify the most stringent emission limitation or control technique that meets the definition of BACT. The top-down BACT analysis below will discuss various NOx control technologies.

The five steps of the process are:

1. Identify all control technologies;
2. Eliminate technically infeasible options;
3. Rank remaining control technologies by control effectiveness;
4. Evaluate most effective controls and document results; and
5. Select BACT.

Step One—Identify all control technologies.
The three basic means of controlling NOx emissions from combustion turbines are wet combustion controls, dry combustion controls, and post-combustion controls. Wet and dry combustion controls act to reduce the formation of NOx

during the combustion process, while post-combustion control remove NOx from the exhaust stream.

The following potential control technologies were identified.

- Wet Combustion Controls
  Water/Steam Injection

- Dry Combustion Controls
  Dry low-NOx combustor design
  Catalytic combustors (e.g., XONON)

- Post-Combustion Controls
  Selective catalytic reduction (SCR)
  EMx system (formerly SCONOx offered by Goal Line Environmental)

Step Two—Eliminate technically infeasible options.
The technical feasibility of the control options identified in step one is evaluated with respect to the equipment proposed.

Water/Steam Injection
Water or steam injection directly into the turbine combustor lowers the flame temperature in the combustor and thereby reduces thermal NOx formation. (Thermal NOx is created by the reaction at higher temperatures of the nitrogen and oxygen in the air.) Water injection typically reduces NOx to 25-42 ppmvd at 15% O_2, and steam injection reduces NOx to 15-25 ppmvd at 15% O_2,. These wet injection techniques are among the most common NOx control techniques for combustion turbines. Thus, this technology is *technically feasible*.

Dry low-NOx combustor design
Dry low-NOx (DLN) combustors use lean, premixed combustion to keep peak combustion temperature low, thus reducing the formation of thermal NOx. The combustor is the space inside the gas turbine where fuel and compressed air are burned. The DLN minimize combustion temperatures by providing a lean premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The resulting lower temperatures reduce NOx formation. Combustors typically reduce NOx to 9-25 ppmvd at 15% O_2. Several turbine vendors have developed the DLN technology for their engines, including the GE

LM2500 turbine proposed for this project. Thus, this technology is *technically feasible*.

DLN combustors, however, are not compatible with wet combustion controls. Either DLN or wet combustion controls may be used, but not both.

Catalytic combustors (e.g., XONON)
Catalytic combustors use a catalyst integrated into the gas turbine combustor to limit temperature below the temperature where NOx is formed. Fuel is partially combusted in the catalyst followed by compete combustion downstream in the burnout zone. Partial combustion in the catalyst produces no NOx, because the catalyst limits the temperature in the combustor and helps stave off the production of NOx. This technology has been commercially demonstrated under the trade name XONON. Each XONON combustor is customized to the particular turbine model and application and is defined through a collaborative effort with the turbine original equipment manufacturer to integrate the hardware into the design. General Electric and Kawasaki are the only turbine vendors to indicate the commercial availability of catalytic combustion systems at the present time, but only on small, less than 10 MW, turbines. Since the proposed turbine is 34 MW units, this technology is ***not** technically feasible*.

Selective catalytic reduction (SCR)
SCR is a post-combustion technique that controls both thermal and fuel NOx emissions. The SCR process involves the injection of ammonia into the turbine exhaust gas streams by means of an ammonia injection grid upstream of the catalyst. The ammonia is a reducing agent that reacts with NOx and oxygen in the presence of a catalyst to form water vapor and nitrogen. The catalyst is not regenerated and requires periodic replacement. The proposed SCR is guaranteed to reduce NOx from 25 ppmvd to 2.5 ppmvd at 15% O_2, except during startup and shutdown events. A typical SCR system is comprised of a SCR reactor with catalyst, ammonia storage tank, and vaporization and injection equipment for the ammonia, a booster fan for the turbine exhaust gas, and instrumentation and control equipment.

Excess ammonia is required for efficient conversion of NOx to nitrogen, because of the imperfect distribution of the ammonia in the catalyst. Thus, a small amount of ammonia remains unreacted in the exhaust stream and is referred to as "ammonia slip." Ammonia slip increases as the catalyst ages, necessitating the use of increasing amounts of ammonia injection to maintain NOx concentrations at or below the design concentration. The ammonia slip from the proposed SCR is guaranteed to meet the BACT limit of 5.0 ppmvd @ 15% O_2, 1-hr average. The slip from a new catalyst is typically lower than the BACT limit.

SCR systems have been widely used in gas turbine applications for many years, almost exclusively in conjunction with other wet or dry NOx combustion controls. Further, SCR systems are commercially available from several vendors. Thus, this technology is *technically feasible*.

EMx system (formerly SCONOx offered by Goal Line Environmental)
The EMx system is a proprietary catalytic oxidation and absorption technology available through EmeraChem LLC (formerly Goal Line Environmental Technologies). EMx is second generation SCONOx NOx absorber technology that does not require ammonia. EMx uses a single catalyst, EMx catalyst, for the removal of CO, VOC, PM, and NOx emissions in turbine exhaust gas by oxidizing nitrogen oxide (NO) to NO2, CO to CO2, and hydrocarbons to CO2 and water, and then adsorbing NO2 onto the catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface.

When all of the potassium carbonate absorber coating has been converted to nitrogen compounds, NOx can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and molecular nitrogen. CO2 in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The EMx catalyst is sensitive to contamination of sulfur in combustion fuel. A secondary catalyst, ESx catalyst, is located upstream of the EMx catalyst to remove the sulfur dioxide in the turbine exhaust stream to prevent masking of the EMx catalyst. [2]

The specified EMx catalyst operating temperature range is 300 to 700°F, which is also a practical limitation for use with refinery process heaters. The typical exhaust temperature range is significantly higher for refinery process heaters and boilers. The EMx catalyst technology is not usable unless the tolerated

[2] Tesoro (Wilmington) Reliability Improvement and Regulatory Compliance Project, Chapter 6: Project Alternatives, 2009

Rule 2005	**New Source Review for RECLAIM**	**April 20, 2001 Application Deem Complete Date: 2012**

temperature range is increased or the exhaust temperature of the heaters is controlled. [3]

To date, EMx has been demonstrated only on natural gas fired combustion turbines. There is no practical experience with operating on flue gas streams from refinery gas-fired equipment. At this time, EMx is not being used in any commercial refinery situation with equipment using a sulfur-bearing fuel gas stream such as refinery fuel gas because SOx will contaminate the catalyst and reduce efficiency over time. The sulfur in refinery gas may interfere with the EMx catalyst's ability to control emissions and consistently comply with BACT NOx requirements. A second catalyst is necessary to remove sulfur species to prevent fouling of the NOx catalyst. Demonstration of the effectiveness for use with higher sulfur-containing fuels (such as, refinery fuel gas) has not yet shown consistent, reliable NOx control in the refinery environment. In addition, although the EMx Technology does not use ammonia, it results in an increase in water use and wastewater discharge, and requires a hydrogen supply, which may generate other environmental impacts, including increased GHG emissions. [1]

Because of the lack of commercial refinery experience, the catalyst's sensitivity to sulfur compounds, and mechanical limitations, the EMx technology is deemed to be ***not*** *technically feasible.*

<u>Step Three—Rank remaining control technologies by control effectiveness</u>. The remaining technically feasible control technologies are ranked by NOx control effectiveness in the table below.

Table 41. NOx Control Technology Alternatives

[3] Oklahoma Department Of Environmental Quality, Air Quality Division Memorandum from John Howell, P.E. to Phillip Fielder, February 2, 2009, Evaluation of Permit Application No. 2007-042-C (PSD) ConocoPhillips Company, Ponca City Refinery Refinery Upgrade Projects

Rule 2005 | **New Source Review for RECLAIM** | **April 20, 2001**
Application Deem Complete Date: 2012

NOx Control Technology	NOx Emissions at 15% O_2	Environmental Impact	Energy Impacts
Water Injection	25-42 ppm	Increased CO/VOC	Decreased Efficiency
Steam Injection	15-25 ppm	Increased CO/VOC	Increased Efficiency
Dry Low-NOx Combustors	9-25 ppm	Reduced CO/VOC	Increased Efficiency
Selective Catalytic Reduction	> 90% reduction 2.5 ppm	Ammonia slip	Decreased Efficiency

Step Four—Evaluate most effective controls and document results.
Water injection with SCR, steam injection with SCR, and dry low-NOx combustors with SCR all result in NOx emissions of 2.5 ppm.

Step Five—Select BACT.
Because the controlled NOx emission rate will be 2.5 ppm with water injection with SCR, steam injection with SCR, or dry low-NOx combustors with SCR, these technologies are all considered BACT. Ultramar has chosen dry low-NOx combustors with SCR for the new gas turbine and duct burner as BACT for NOx. SCR is proven technology on refinery gas equipment.

Emissions
Ultramar's proposal of 2.5 and 40 ppm for NOX and SOx is acceptable as BACT since the duct burner will burn a blend of refinery gas and natural gas while the other aeroderivative engine Achieved in Practice listed above operate only natural gas. Ultramar's refinery gas historically averaged 51 ppm (daily) and 52 ppmv (monthly), based on operations over a 12 month period. To meet the 40 ppmv SOx BACT limit, Ultramar will blend the refinery gas with natural gas before the fuel gas is burned in the duct burner.

Therefore, the proposed control levels will meet the BACT requirements for NOx and SOx.

(B) Modeling. Modeling is required for NOx emissions per Rule 2005(c)(1)(B). Rule 2005 requires that through modeling, the applicant substantiate that the

Rule 2005	New Source Review for RECLAIM — April 20, 2001 — Application Deem Complete Date: 2012

project does not exceed the most stringent ambient air quality standard nor a significant change in air quality concentration. Rule 2005 does not require modeling for SOx emissions. Maximum project impacts of NOx emissions were determined using the SCREEN3 model for 1 hour impacts, and ISCST3 model for the annual standard. Table 42 shows the applicable standards and the results from Ultramar's modeling analysis.

Table 42. Cogeneration Unit NOx Modeling Results

Pollutant	Averaging Time	Significant Change in Air Quality Concentration ($\mu g/m^3$)[a]	Most Stringent Air Quality Standard		Ambient Background Concentration ($\mu g/m^3$)	Calculated Concentration ($\mu g/m^3$)	Background with Total Concentration ($\mu g/m^3$)
			($\mu g/m^3$)[a]	($\mu g/m^3$)[b]			
NO2	1-hour	20	**500**	339	245.44	28.07	**273.51**
	Annual	1	**100**	57	40.03	0.27	**40.30**

Evaluation criteria **bolded**
a From Rule 2005, Table A-2
b Most stringent state (California) ambient air quality standard

The District's Planning, Rule Development & Area Sources staff reviewed the air quality analysis from the above sources impacted by this project. Planning staff found that the appropriate model options were used and the air quality was performed per the District's modeling requirements. The total air quality impacts (background and the incremental project impacts) comply with Rule 2005 and will not result in a significant increase in the air quality concentration for NO2.

2005(c)(2)

Sufficient RECLAIM Trading Credits. Ultramar is required to demonstrate that the facility holds sufficient RTCs to offset the annual emission increase for the first year of operation at a 1-to-1 ratio. The NOx and SOx emission increase from the new gas turbine and duct burner for the first year of operation (Commissioning Year) is 44,137 lbs/year and 15,318 lbs/year, respectively. Completion of construction and operation of the equipment in this project is anticipated in 2013. For the year 2013, Ultramar has the following RTCs currently in their account:

Table 43. NOx and SOx RTC Holdings

RECLAIM Pollutant	Year 2013 RTCs Holding (lbs/year)

Rule 2005	**New Source Review for RECLAIM** **April 20, 2001** **Application Deem Complete Date: 2012**
	(see table below) The facility currently holds sufficient RTCs to offset the annual emission increase for the first year of operation at a 1-to-1 ratio.
2005(c)(3)	Change of Operator. This subparagraph does not apply since this project is not for a change of operator.
2005(c)(4)	Allocation Increase greater than Starting Allocation. The emission increase due to this project will not increase the facility's annual Allocation to a level greater than the facility's starting allocation (NOx: 849,881 lbs/year; SOx: 1,010,497 lbs/year) plus non-tradable credits (NOx: 729,265 lbs/year; SOx: 0 lbs/year).
2005(d)	Emission Increase. NOx and SOx emission increase from this project is 44,137 lbs/year and 15,318 lbs/year, respectively, in a commissioning year and 41,409 lbs/year and 15,943 lbs/year, respectively, in a non-commissioning year as shown in Table 20.
2005(e)	Trading Zone Restrictions. The emission increase due to this project will not increase the facility's annual Allocation to a level greater than the facility's starting allocation (NOx: 849,881 lbs/year; SOx: 1,010,497 lbs/year) plus non-tradable credits.
2005(f)	Offsets. The facility is not required to hold RTCs at the commencement of each compliance year since it is not a new or relocated RECLAIM facility or existing RECLAIM facility with an application to increase its annual allocation greater than the facility's starting allocation plus non-tradeable credits. *Not Applicable*
2005(g)	Additional Federal Requirements for Major Stationary Sources
	(1) *Statewide Compliance. Certify that all major sources in the state under control of the applicant are in compliance or on a schedule for compliance with all applicable federal emissions standards.*

NOx	July 2012-June 2013	51,475
	Jan 2013-Dec 2013	467,945
SOx	July 2012-June 2013	228,606
	Jan 2013-Dec 2013	397,911

Rule 2005	**New Source Review for RECLAIM** — **April 20, 2001** **Application Deem Complete Date: 2012**
	See the above discussion under Rule 1303(b)(5)(B).
	(2) *Alternative Analysis. Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source.* See the above discussion under Rule 1303(b)(5)(A).
	(3) *Compliance Through California Environmental Quality Act.* See the above discussion under Rule 1303(b)(5)(D).
	(4) *Protection of Visibility. Conduct a modeling analysis for plume visibility if the net emission increase from the new or modified source exceeds 40 tons/year of NOx; <u>and</u> the location of the source is within specified distance from a Class I area..* See the above discussion under Rule 1303(b)(5)(C).
2005(h)	Public Notice. A public notice is required for this project. See the discussion under Rule 212.
2005(i)	Rule 1401. See the discussion under Rule 1401.
2005(j)	Compliance with State and Federal New Source Review Requirements. The NOx and SOx emission increases will be included in the NSR Tracking System so the emissions can be reported the District Governing Board regarding the effectiveness of Rule 2005 in meeting the state and federal NSR requirements.

Rule 2011	**Requirements For Monitoring, Reporting, And Recordkeeping For Oxides Of Sulfur (SOx) Emissions** — **May 6, 2005**
	This rule establishes the monitoring, reporting and recordkeeping requirements (MRR) for SOx emissions under the RECLAIM program. According to 2011(c)(1)(D), any equipment that burns refinery, landfill or sewage digester gaseous fuel, except gas flares are Major SOx sources. In addition, according to 2011(c)(1)(F), any SOx source elected by the facility to be monitored with a CEMS is a Major SOx source. The existing three boilers and the new proposed duct burner in the Cogeneration Unit operate on refinery gas. Therefore, the existing three boilers and new proposed Cogeneration Unit (gas turbine and duct

Rule 2011	**Requirements For Monitoring, Reporting, And Recordkeeping For Oxides Of Sulfur (SOx) Emissions**	**May 6, 2005**

burner) will be classified as RECLAIM Major SOx Sources that are subject to the maintenance, recordkeeping and reporting (MRR) requirements of this rule. The gas turbine only burns natural gas. In accordance with Rule 2000(b)(62) RECLAIM POLLUTANTS are defined as NOx emissions and SOx emissions at a facility subject to RECLAIM requirements excluding any NOx or SOx emissions from on-site, off-road mobile sources and any SOx emissions from equipment burning natural gas exclusively…" As a result, the gas turbine is not SOx RECLAIM source. However, since the gas turbine and duct burner are vented to a single stack, the gas turbine will also be classified as a Major SOx Source.

This rule requires that each major source be equipped with a CEMs or SCEMS (semi continuous) that measures one of the following:

- Stack SOx concentration and exhaust gas flow rate, or
- SOx concentration, stack O2 concentration, and fuel flow rate, or
- Fuel sulfur content and fuel flow rate

Ultramar utilizes a certified SCEMS consisting of refinery fuel gas sulfur analyzer and flow rate monitors on each boiler. The certified sulfur analyzer will continue to measure the TRS concentration of the fuel provided to the combustion boilers. The refinery fuel gas is supplied to the boilers from 88-V-9003 mix drum. This same refinery fuel gas currently supplied to the boilers will also be supplied to the new Cogeneration Unit duct burner. The total sulfur in Ultramar's refinery gas averages 60 ppmv. To meet the 40 ppmv SOx BACT limit, Ultramar will blend the refinery gas with natural gas before the fuel gas is burned in the duct burner. Ultramar shall install a separate analyzer to continuously monitor the total sulfur compounds calculated as H2S concentration of the refinery fuel gas before being burned in the duct burner.

Rule 2011(f)(6) specifies that all required or elected monitoring, reporting and recordkeeping systems shall be installed no later than 12 months after the initial start up of the major SOx source. During the interim period between the initial start up of the major SOx source and the provisional certification date of the CEMS, a SOx emission factor will be used to estimate and report mass SOx emissions. The interim reporting period for the subject Cogeneration Unit can be broken down into the following parts: commissioning and normal operation.

Rule 2011	**Requirements For Monitoring, Reporting, And Recordkeeping For Oxides Of Sulfur (SOx) Emissions** **May 6, 2005**
	The emission factors for these periods are developed from the emission estimates shown in the Appendix G of this evaluation. RECLAIM SOx CEMS certification and QA/QC requirements are contained in Rule 2011, Appendix A, Chapter 2 and Attachment C. Quality Control requirements of this rule include semi-annual Relative Accuracy Test Audits (RATA). For the fuel sulfur GCs RATAs, Ultramar performs semi-annual Cylinder Gas Audits as specified in Attachment C of the Rule 2011 Protocol, which is Appendix A to Rule 2011. The relative accuracy of the fuel flow meters is determined by semi-annual stack RATA. The District's Source Test group routinely reviews the reports for these CGAs/RATAs. Compliance with the QA/QC requirements of this rule is expected.

Rule 2012	**Requirements For Monitoring, Reporting, And Recordkeeping For Oxides Of Nitrogen (NOx) Emissions** **May 6, 2005**
	This rule establishes the monitoring, reporting and recordkeeping requirements (MRR) for NOx emissions under the RECLAIM program. Existing Boilers 86-B-9000, B-9001, and B-9002 are classified as Major NOx Sources since they burn refinery gas. The new cogeneration unit consisting of gas turbine and duct burner will also be classified as Major NOx sources are subject to the MRR requirements of this rule. Appendix A, Chapter 2.A.1. specifies the Facility Permit holder of each major NOx equipment shall install, calibrate, maintain, and operate an approved CEMS to measure and record the following: • Nitrogen oxide concentrations in the gases discharged to the atmosphere • Oxygen concentrations if required for calculation of the stack gas flow rate • Stack gas volumetric flow rate This section also specifies that calculation of stack gas volumetric flow rate using one of the following alternative methods is acceptable: heat input, oxygen mass balance, or nitrogen mass balance. The CEMS on the existing boilers utilize heat input and oxygen concentration to calculate NOx mass emissions. The approved NOx analyzer range is 0-25 ppmv. The mass NOx emissions for the proposed Cogeneration Unit will also be monitored with a

Rule 2012	**Requirements For Monitoring, Reporting, And Recordkeeping For Oxides Of Nitrogen (NOx) Emissions**	**May 6, 2005**
	NOx CEMS including fuel flow meters. According to 2002(h)(6), an operator which installs a new major NOx source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting and recordkeeping systems no later than 12 months after the initial start up. During the interim period between the initial start up of the major NOx source and the provisional certification date of the CEMS, a NOx emission factor is used to estimate and report mass NOx emissions. The interim reporting period for the subject Cogeneration Unit can be broken down into the following parts: commissioning and normal operation. The emission factors for these periods are developed from the emission estimates shown in the Appendix G of this evaluation. The NOx emissions during the commissioning period are primarily uncontrolled emissions but the turbine is not operating continually during this period (376 hours over 24 days). Based on Ultramar's record of compliance with RECLAIM monitoring, recordkeeping and reporting requirements, compliance with the requirements of this regulation is expected.	

Regulation XXX	**TITLE V PERMITS**	**November 5, 2010**
	The initial Title V permit for the refinery was issued on May 29, 2010. In accordance with Rule 3000, this Title V revision qualifies as a Significant Revision for the following reason: • Installation of a new equipment (Cogeneration) that will be subject to an NSPS and NESHAP [Rule 3000(b)(31)(I)], namely NSPS Subpart Ja, NSPS Subpart KKKK, NESHAP Subpart YYYY, and NESHAP Subpart DDDDD~~; and~~ Therefore, this permit revision will be subject to a 45-day EPA review and 30-day public notice in accordance with Rule 3006.	

PART 2 STATE REGULATIONS

California Environmental Quality Act (CEQA)	
	According to the District's CEQA guidelines, the thresholds for significant effect are:

NOx	55 pounds per day
VOC	55 pounds per day
PM10	150 pounds per day
CO	550 pounds per day
SOx	150 lbs per day

Based on the emissions shown in Table 21, this proposed modification and new installations make this a significant project. Therefore, preparation of a CEQA document was required. A Notice of Preparation and Initial Study (NOP/IS) was issued on March 30, 2012 for a 34-day comment period and ended on May 3, 2012. The NOP/IS concluded the proposed project would not create significant adverse environmental impacts. Subsequent to the release of the NOP/IS, further evaluation of air quality, greenhouse gas emissions, and hazards and hazardous materials did not identify any significant adverse impacts from the proposed project. Therefore, in lieu of an Environmental Impact Report, the District prepared a Negative Declaration (ND) to address the potential adverse environmental impacts associated with the proposed project. An ND for a project subject to CEQA is prepared when an environmental analysis of the project shows that there is no substantial evidence that the project may have a significant effect on the environment. The draft ND was issued on April 12, 2013. The public review period for this document was from April 12, 2013 through May 14, 2013. A request from the public to extend the public review period an additional 20 days was made. This request was granted by the CEQA group. The ND is pending certification.

PART 3 FEDERAL REGULATIONS

40 CFR60 Subpart Db	**Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units**
	The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating

40 CFR60 Subpart Db	**Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units**
	unit of greater than 29 MW (100 million Btu/hour). This subpart applies to the following equipment since they are rated greater than 100 million Btu/hour and constructed after June 19, 1984: • Boiler 86-B-9001 • Boiler 86-B-9002 Existing boiler 86-B-9000 is rated less than 100 million Btu/hour and constructed before 1984. The HRSG and duct burners on the new Cogeneration Unit will not be subject to the requirements of this regulation because they will be subject to 40CFR60 Subpart KKKK. According to §60.4305(b) in Subpart KKKK, heat recovery steam generators and duct burners regulated under Subpart KKKK are exempted from the requirements of subparts Da, Db, and Dc.
60.42b	***Standards for Sulfur Dioxide*** (c) - Affected facilities which also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under subpart J (§60.104). Existing boilers 86-B-9001 and 9002 are subject to the SO2 standards of NSPS Subpart J so they are not subject to the SO2 standards of this regulation.
60.43b	***Standards for Particulate Matter*** 60.43(a), (b), (c), and (d) contain PM standards for steam generating units that were constructed, modified, or reconstructed after June 19, 1984 and combust coal, oil, wood, or municipal waste respectively but there are no PM standards for gaseous fuel fired units constructed after 1984. 60.43b(h) contains standards for units constructed, modified, or reconstructed after February 28, 2005, which combust coal, oil, wood, or a mixture of these fuels. There are no PM standards for gaseous fuel fired units. Existing boilers 86-B-9001 and 9002 only burn gaseous fuels so they are not subject to a PM standard under this regulation.
60.44b	***Standards for Nitrogen Oxides*** According to 60.44b(1)(ii) and 60.44b)(4)(i), respectively, existing boilers 86-B-9001 and 9002 are subject to a NOx emission limit of 0.20 lb/MMBtu (expressed as NO2) on a 30-day rolling average basis. This emission rate is comparable to

40 CFR60 Subpart Db	**Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units**
	160 ppmv @ 3% O2 or 55 ppmv @ 15% O2. With proper operation of the SCR control systems connected to each boiler, NOx emissions are well below the limits of this regulation. Each of the existing units is equipped with a NOx CEMS to show compliance with this emission rate. Compliance with this NOx emission rate is expected.

Subpart J	**Standards of Performance for Petroleum Refineries**
§60.100	*Applicability, designation of affected facility, and reconstruction.* The provisions of this subpart are applicable to fuel gas combustion device which commences construction or modification after June 11, 1973. Fuel gas combustion device is defined as "*any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid*". Fuel gas is defined as any gas which is generated at a petroleum refinery and which is combusted (e.g, refinery gas). Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. This subpart applies to the following equipment since they are fuel combustion devices constructed after 1973: • Existing Boiler 86-B-9001 • Existing Boiler 86-B-9001 • Existing Boiler 86-B-9002
§60.104(a)(1)	*Standards for sulfur oxides*. The operator shall not burn in the heaters and boilers any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf, 160 ppm). Ultramar operates a H_2S CEMS on their fuel gas system. The 88-AI-942 CEMS analyzes all treated fuel gas that is normally used within the refinery for heater and boiler fuel gas combustion and other process purposes. This is the same refinery fuel gas stream that will be fed to the new Cogeneration duct burner. In the Periodic Monitoring & Exception Report for the report period July 1 through December 31, 2012 submitted by Ultramar to EPA, Ultramar reported 0 hours (out of 4,368 hours) in which the H_2S exceeded 230 mg/dscm in the fuel gas burned. Ultramar operates a fuel gas treating unit (Unit 88, A/N 465660) to reduce total sulfur concentrations in the fuel gas that is supplied to the fuel gas combustion equipment operated in the refinery. This fuel gas treating unit reduces total sulfur

Subpart J	**Standards of Performance for Petroleum Refineries**
	concentrations to sub-100 ppmv levels using a caustic solution to react with the sulfur compounds in the fuel gas to produce water and sodium sulfide or sodium mercaptides, which are water-soluble and stay in solution. Cleaned fuel gas exits the top of the caustic wash knockout drum (88-V-1), while the sodium sulfide/sodium mercaptides-enriched caustic solution exits the bottom. The cleaned fuel gas next is mixed with water in the water wash static mixer (88-MX-2) to ensure the removal of any entrained caustic particles. This fuel gas/water mixture is then separated in the water wash knockout drum (88-V-2), in which the clean fuel gas leaves the top of the vessel and the wash water exits the bottom of the vessel. The clean fuel gas then enters the refinery fuel gas system to be used by the refinery gas users (e.g., boilers, heaters, proposed duct burner) and/or Air Products. The treated fuel gas is equipped with a total sulfur analyzer. The permit for the new Cogeneration Unit will be conditioned with a BACT 40 ppmv (3-hr average) Total Sulfur limit. Compliance with both the 40-ppmv TRS and 160 ppmv H2S fuel gas limits is expected.
§60.105(a)(4)	*Monitoring of emissions and operations.* Ultramar operates two H_2S CEMS on their fuel gas system. The 88-AI-942 CEMS analyzes all treated fuel gas that is normally used within the refinery for heater and boiler fuel gas combustion and other process purposes. The 88-AI-945 CEMS analyzes all treated fuel gas that is normally sent directly to the flare for combustion purposes. Each of these analyzers was installed to demonstrate compliance with 40CFR 60.104(a)(1) and 60.105(a)(4)-Monitoring of emissions and operations.

40CFR60 Subpart Ja	**Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007**
	This NSPS is applicable to the following affected facilities in petroleum refineries which were constructed, reconstructed, or modified after May 14, 2007: • Fluid Catalytic Cracking Unit Catalyst Regenerators, • Fluid Coking Units, • Delayed Coking Units, • Fuel Gas Combustion Devices (except flares), and • Claus Sulfur Recovery Plants (SRPs) Fuel gas combustion device is defined "*as any equipment, such as process heaters, boilers, and flares, used to combust fuel gas, except facilities in which gases are*

40CFR60 Subpart Ja	**Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007**
	combusted to produce sulfur or sulfuric acid". Fuel gas is defined as any gas which is generated at a petroleum refinery and which is combusted. Fuel gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Existing boilers 86-B-9000, B-9001, B-9002 are not subject to this regulation because they have not been modified after May 17, 2007. The Cogeneration Unit's gas turbine is not subject to this regulation because it will combust only commercial natural gas, which is produced outside of the refinery. However, the HRSG's duct burner will be subject to this regulation since it will combust a blend of refinery fuel gas and natural gas. According to §60.102a(g)(1), the owner or operator of an effected fuel gas combustion device shall comply with either stack gas SO2 concentration limits of 20 ppmvd (0% O2, 3-hr rolling avg.) and 8 ppmvd (0% O2, 365 successive calendar day rolling avg.) or fuel gas H_2S concentration limits of 162 ppmv (3-hr rolling avg.) and 60 ppmv (365 successive calendar day rolling avg.). As discussed above, Ultramar operates a fuel gas treating unit to achieve sub-100 ppmv TRS concentrations in the fuel gas sent to the fuel mix drum. Compliance with the 160 ppmv H2S limits of this regulation is expected. This regulation also contains a stack gas NOx concentration limit of 40 ppmvd (0% O2, 24-hr rolling avg.) for process heaters with a rated capacity of greater than 40 MMBtu/hr. A process heater is defined as "an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam". The duct burner is not subject to this NOx limit since it is not a process heater.

40CFR60 Subpart GG	**Standards of Performance for Stationary Gas Turbines**
§60.330	This NSPS is applicable to all stationary gas turbines that commenced construction, reconstruction, or modification after Oct. 3, 1977 and has a heat input at peak load of 10.7 gigajoules (10 MMBtu) per hour, based on the fuels lower heating value.

40CFR60 Subpart GG	**Standards of Performance for Stationary Gas Turbines**
	According to §60.4305(b) in Subpart KKKK, turbines regulated under Subpart KKKK are exempted from the requirements of subpart GG. The proposed Cogeneration turbine and duct heater are subject to 40CFR60 Subpart KKKK. Therefore, the new Cogeneration Turbine is not subject to the requirements of this regulation.

40CFR60 Subpart GGG	**Standards of Performance for Equipment Leaks of VOCs in Petroleum Refineries**
§60.590	This NSPS is applicable to affected facilities that begin construction after January 4, 1983. The following are affected facilities under this subpart: ▪ Compressors ▪ The group of all the equipment within a process unit. The definition for process unit follows: "*Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Even though the existing boilers 86-B-9001 and 86-B-9002 were constructed after the January 4, 1983 applicability date of this regulation, they are not "affected facilities" since they are not part of a "process unit" as defined in this regulation and they do not contain any compressors that are in VOC service. Existing boiler 86-B-9000 was constructed before 1983. Therefore, Subpart GGG is not subject to any equipment in this project.

40CFR60 Subpart GGGa	**Standards of Performance for Equipment Leaks of VOCs in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced after November 7, 2006**
§60.590a	This NSPS is applicable to affected facilities in refineries that begin construction

40CFR60 Subpart GGGa	**Standards of Performance for Equipment Leaks of VOCs in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced after November 7, 2006**
	after November 7, 2006. The following are affected facilities under this subpart: ▪ Compressors ▪ The group of all the equipment within a process unit. The proposed Cogeneration Unit is not a process unit as defined in this regulation. The Cogeneration Unit permit unit does not contain any compressors. For these reasons, the equipment in the Cogeneration Unit is not subject to the requirements of this regulation.

40CFR60 Subpart KKKK	**Standards of Compliance for Stationary Combustion Turbines**
§60.4300	This subpart establishes NOx and SO_2 emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value, that commenced construction, modification or reconstruction after February 18, 2005. The heat input capacity of the proposed Cogeneration Unit turbine is 341.6 MMBtu/hr (HHV) so it will be subject to the requirements of this regulation. Only heat input to the combustion turbine is used to determine whether this subpart applies to the turbine. Any additional heat input to the associated heat recovery steam generators (HRSG) or duct burners should not be included when determining the peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.
§60.4320	*NOx Limit.* According to §60.4320 and Table 1 to this NSPS, this turbine is subject to a NOx emission limit of 25 ppmv (@ 15% O_2) since it has a heat input capacity between 50 and 850 MMBtu/hr and fires natural gas. This limit is well above the 2.5 ppmv NOx limit that will be imposed on the proposed Cogeneration Unit under Rule 2005 (BACT). The Cogeneration exhaust stack will be equipped with a NOx CEMS to show compliance with this emission limit. Note that the emission limits of this subpart apply to both the combustion turbine and a HRSG/duct burner.

40CFR60 Subpart KKKK	**Standards of Compliance for Stationary Combustion Turbines**
§60.4325	*SOx Limit.* According to §60.4325, the turbine is also subject to one of the following SO_2 related limits: (1) Exhaust gas with SO_2 greater than 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or (2) Fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. The turbine will be permitted to burn natural gas only, while the duct burner will burn a blend of refinery gas and natural gas. The sulfur concentration of natural gas supplied to the refinery is less than 1 grain S/100 scf (16 ppmv) and the refinery fuel/natural gas blend supplied to the duct burners will be conditioned with a 40 ppmv (1-hr average) sulfur limit. These fuel concentrations of 1 grain S/100 scf (16 ppmv) and 40 ppmv are equivalent to 0.0031 lb SO_2/MMBtu and 0.0065 SO_2/MMBtu, respectively. To convert 1 grain S/100 scf and 40 ppm sulfur to units of lb SO_2/MMBtu, • Natural Gas: $\left(\frac{1\ \text{grain S}}{100\ \text{ft}^3}\right)\left(\frac{1\ \text{lb}}{7000\ \text{grain}}\right)\left(\frac{\text{ft}^3}{1017.6\ \text{Btu [HHV]}}\right)\left(\frac{1\ \text{E+06 Btu}}{\text{MMBtu}}\right)\left(\frac{64\ \text{lb SO}_2\text{/lb-mole}}{32\ \text{lb S/lb-mole}}\right)$ $= 0.0028$ lb SO_2/MMBtu < 0.060 lb SO_2/MMBtu • Refinery Fuel Gas (Mixture of refinery gas and natural gas): $\left(\frac{40}{1\text{x}10^6}\right)\left(\frac{\text{ft}^3}{1143.6\ \text{Btu [HHV]}}\right)\left(\frac{\text{lb-mol}}{385.5\ \text{scf}}\right)\left(\frac{64\ \text{lb SO}_x}{\text{lb-mole}}\right)$ $= 0.0058$ lb SO_2/MMBtu < 0.060 lb SO_2/MMBtu Thus, the gas turbine and duct burner are expected to be in compliance with this section.
§60.4340	*Monitoring.* To demonstrate continuous compliance with the NOX emission limit, Ultramar shall (a) perform annual performance tests or (b) calibrate, maintain and operate a continuous monitoring systems. The Cogeneration Unit will be required

40CFR60 Subpart KKKK	**Standards of Compliance for Stationary Combustion Turbines**
	to install CEMS to comply with RECLAIM requirements for NOx Major Sources. Therefore, NOx monitoring requirements are satisfied. Daily monitoring of the sulfur content of the fuel is required if the fuel limit is selected. However, if the operator can provide supplier data showing the sulfur content of the fuel is less than 20 grains/100 scf for natural gas, then daily fuel monitoring is not required. The turbine will only fire natural gas provided by the Southern California Gas Company which contains less than 1 grains-sulfur/100scf. Southern California Gas Company-Rule 30 specifies that the natural gas shall not contain more than 0.75 of a grain of total sulfur compounds, measured as sulfur, per 100 standard cubic feet (12.6 ppm). Therefore, daily monitoring of the natural gas sulfur content is not required. For the blend of refinery gas and natural gas burned in the duct burner, total sulfur content of the refinery fuel and natural gas mixture along with the fuel flow rate will be measured to comply with RECLAIM. This fuel sulfur monitoring system will also need to satisfy the monitoring requirements of this NSPS.

40CFR63 Subpart CC	**National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries**
§63.640	This subpart applies to petroleum refining sources and related emission sources that are specified in section 63.640 (c)(5) through (c)(7) (e.g. miscellaneous process vents (except for FCCU, SRU, and CRU vents), storage vessels, wastewater stream, equipment leaks, gasoline loading racks, marine vessel loading, etc.) that are located in a major source and emit or have equipment emitting one or more of the hazardous air pollutants (HAPs) listed in Table 1 of this subpart. The only source in the proposed Cogeneration Unit that should be evaluated as potential affected sources under this NESHAP are fugitive components in the refinery fuel gas and natural gas supply systems. The equipment leak standards as specified in §63.648 are applicable to fugitive components that are “in organic hazardous air pollutant service”. In “organic hazardous air pollutant service” is defined as a piece of equipment that either contains or contacts a fluid (liquid or

40CFR63 Subpart CC	**National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries**
	gas) that is at least 5% by weight of total organic HAPs as determined according to §63.180(d). §63.640(d)(5) specifies that refinery fuel gas systems or emission points routed to refinery fuel gas systems are not affected sources, which are subject to this subpart. The refinery fuel gas system qualifies for this exemption. The natural gas supply system does not qualify as a refinery fuel gas system since the gas is not generated at the refinery but the HAP content of the natural gas is well below 5 percent so these components are not subject to this regulation. Due to the reasons stated above, the proposed Cogeneration Unit is not subject to this regulation.

40CFR63 Subpart YYYY	**National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines**
§63.6080	This NESHAP establishes emission limitations and operating limitations for HAP emissions from stationary combustion turbines located at major sources of HAP emissions. The rule was initially promulgated on March 4, 2004. On April 7, 2004, EPA proposed to amend the rule by deleting subcategories from the stationary combustion turbines source category and proposed to stay the rule for lean premix gas-fired turbines and diffusion flame gas-fired turbines subcategories, which are the two principal subcategories EPA proposed to delist. EPA cited this action was necessary to avoid wasteful and unwarranted expenditures on installation of emission controls which would not be required if the subcategories are delisted. On August 18, 2004, EPA stayed the effectiveness of the emissions and operating limitations in the stationary combustion turbines NESHAP for new sources in the lean premix gas-fired turbines and diffusion flame gas-fired turbines subcategories in §63.6095(d) - *Stay of standards for gas-fired subcategories*. The proposed GE LM2500 is a lean, premixed gas-fired turbine. Therefore, in accordance with §63.6095(d), the operator of a new stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine only needs to comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register. To date, EPA has not taken final action to require compliance or published a document in the Federal Register removing the stay or delisting lean

40CFR63 Subpart YYYY	**National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines**
	premix gas-fired stationary combustion turbines as a source category subject to the standards in this subpart. No additional analysis is required. Condition H23.x3 will be added to specify the gas turbine is subject to Subpart YYYY.

40CFR63 Subpart DDDDD	**National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters**
§63.11140	This maximum achievable control technology (MACT) standard was originally promulgated by EPA on September 13, 2004 and was vacated and remanded by the US Court of Appeals for the District of Columbia Circuit on June 19, 2007. A new rule was proposed on June 4, 2010. In Spring 2011, shortly after issuing the March final standards for major source boilers in March 2011, EPA issued an administrative stay of the effective dates to further reconsider and accept comments on new proposals submitted to change the rule. In December 2011, EPA proposed updated standards to the rule. On January 9, 2012, a federal court ruled the EPA's stay of the effective dates was not allowed (vacating the effective date stay), and thus the rule is considered to be in effect. In response to the court ruling, EPA indicated in a memorandum on February 7, 2012 that it is exercising its enforcement discretion not to enforce the provisions of the new boiler rule until new a new rule is issued. In Spring 2012, EPA announced it will take steps to finalize the changes to the boiler standards. On December 21, 2012, EPA finalized changes to Subpart DDDDD. Therefore, this MACT standard is applicable to all industrial, commercial and institutional boilers and process heaters. In §63.7575 of this regulation, the definitions that determine applicability and pertinent requirements for this project are: ***Boiler*** means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. ***Natural gas*** means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal

40CFR63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters

constituent is methane; or

(2) Liquid petroleum gas, as defined in ASTM D1835 (incorporated by reference, *see* § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 mega joules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot); or(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure $C_3 H_8$.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam

40CFR63 Subpart DDDDD	**National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters**
	generators. Based on these definitions, the existing boilers (86-B-9000, 86-B-9001, and 86-B-9002) and the duct burner associated with heat recovery steam generator for the proposed Cogeneration Unit would be subject to the proposed regulation as boilers. Existing units will be required to comply with the regulation within three years after the final rule is published in the federal register. §63.7499 defines fifteen (15) subcategories of boilers and process heaters. The existing boilers and Cogeneration Unit duct burners/HRSGs fit into the subcategory specified as *(l) Units designed to burn natural gas, refinery gas or other gas 1 fuels.* Emission limits for new and existing boilers and process heaters are specified in Tables 1 and 2 of the regulation. Tables 1 and 2 do not contain any emission limits for new or existing boilers or process heaters in the natural gas/refinery gas category. In Table 3 of the regulation, boilers and process heaters in the natural gas/refinery gas subcategory that have a heat input capacity greater than 10 MMBtu/hr would be subject to an annual tune-up. Additionally, all existing boilers would be subject to a one-time energy assessment performed by qualified personnel. Since the existing boilers and Cogeneration Unit duct burner are not subject to any emission limits, they are also not subject to any of the operating limits, performance testing, or other compliance requirements specified in Tables 4 through 8 of the regulation. No changes to the permit or additional action are required at this time. Condition H23.x4 will be added to specify the boilers and duct burner are subject to Subpart DDDDD.

ADDITIONAL FEDERAL REGULATIONS

40CFR PART 64	**Compliance Assurance Monitoring**
§64	This regulation applies to stationary sources that utilize control equipment to comply with a criteria pollutant emission limit. The purpose is to ensure that the stationary source complies with the emission limit(s) by monitoring the operation and maintenance of the control equipment. As specified in §64.2(a), the requirements of this regulation apply to a stationary

40CFR PART 64	**Compliance Assurance Monitoring**
	source at a major source that is required to obtain a part 70 or 71 permit and satisfies all of the following criteria: (1) The source is subject to an emission limit or standard for an air pollutant (or a surrogate thereof) except for an emission limit that is exempt under §64.2(b)(1); (2) The source uses a control device to achieve compliance with the emission limit or standard; and (3) The potential pre-control emissions of the pollutant are greater than or equal to the major source threshold for the pollutant. *Control device* is defined in §64.1 as equipment, other than inherent process equipment, that is used to destroy or remove air pollutant(s) prior to discharge to the atmosphere. The CAM Rule contains the following exemptions, which are specified in §64.2(b)(1): (i) Emission limits or standards for NSPSs or NESHAPs that were proposed after 11-15-90; (ii) Stratospheric ozone protection requirements under Title VI of the CAA; (iii) Acid rain requirements under 40CFR72; (iv) Emission limitations or standards that apply solely under an emissions trading program; (v) An emission cap that meets the requirements in §70.4(b)(12); (vi) Emission limits for which a part 70 (Title V) permit specifies a continuous compliance determination method. *Continuous compliance determination method,* which is referenced in the exemption specified in §64.2(b)(1)(vi), is defined in §64.1 as a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated

40CFR PART 64	**Compliance Assurance Monitoring**
	directly with the compliance limit. The existing boilers and proposed new Cogeneration Unit are potentially subject to this regulation for NOx, CO, and VOC since the pre-control emissions of these pollutants exceed the South Coast Air Basin major source threshold of 10 ton/yr, 50 ton/yr and 10 ton/yr, respectively, and each of the units currently utilize or will utilize an SCR for control of NOx and a CO catalyst for control of CO and VOC. The units are not equipped with control devices for PM10 and SOx so CAM is not applicable for these pollutants. For existing 86-B-9001 and 86-B-9002 boilers, the NOx and CO CEMS meet the definition for a continuous compliance determination method. For the proposed Cogeneration Unit, the NOx and CO CEMS required will also meet the definition for a continuous compliance determination method (Conditions D82.x1 and D82.x2). Therefore, the existing boilers (86-B-9001 and 86-B-9002) and new Cogeneration Unit is exempt from CAM for NOx and CO the exemption specified in §64.2(b)(1)(vi). The CO CEMS is also believed to provide an adequate determination of continuous compliance with the VOC emission limits. In development of the MACT Standard for FCCUs (40CFR60 Subpart UUU), EPA determined that CO emissions are a good surrogate for organic HAPS for FCCUs since efficient combustion in the regenerator that would yield low CO emissions would also be expected to yield low organic HAP emissions. For the subject Cogeneration Unit, CO and VOC concentrations are a function of combustion efficiency and control efficiency of the CO catalyst. CO emissions are the best available indicator of combustion efficiency and the efficiency of the CO catalyst. The CO CEMs will be supplemented with a VOC source test every three years. For the reasons discussed above, a CAM Plan is not required for the existing boilers and proposed Cogeneration Unit.

40CFR PART 72	**Acid Rain Program**
§72	§72.6(b) The following types of units are not affected units subject to the requirements of the Acid Rain Program: (4) a Cogeneration facility which (i) (for pre 11/15/1990 Cogenerations) was constructed for the purpose of supplying equal

40CFR PART 72	**Acid Rain Program**
	to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis) or (ii) (for post 11/15/1990 Cogenerations) supplies equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis). The Ultramar Refinery is currently a net importer of electrical power. Construction of the new Cogeneration Unit will significantly reduce or eliminate the importation of electrical power but the refinery will not export for sale a significant amount of electrical power. This regulation is not applicable to the subject Cogeneration Unit.

CONCLUSION / RECOMMENDATION:

Based on the foregoing evaluation, it is expected that the subject applications will comply with all applicable District Rules and Regulations.

It is recommended that permits to operate be issued to the existing boilers 86-B-9000 and 86-B-9001. In addition, it is recommended that permits to construct be issued for boiler 86-B-9002 and proposed Cogeneration Unit and associated APCS.

Appendices

A. Hourly Emissions:
Normal Operations
Startup, Shutdown, and Commissioning

B. Monthly Emissions
Commissioning Year
Non-Commissioning Year

C. 30-day Average
Commissioning Year
Non-Commissioning Year

D. Annual Emissions
Commissioning Year
Non-Commissioning Year

E. AEIS Emissions
Non-Commissioning Year, Uncontrolled and Controlled

F. Emission Offsets RECLAIM Pollutants (NOx/SOx)

G. Interim Emission Factors during Commissioning
Interim Emission Factors after Commissioning and Before Provisional CEMS Approval

H. Steady State Emissions Computation, Rev. I- August 1, 2012

I. Fugitive Emissions

J. Startup Emissions

K. Shutdown Emissions

L. Estimated Commissioning Emissions

M. Toxic Air Contaminant (TAC) Emissions

N. Projected Boiler Firing and Cogeneration Operation