Application Nos.

PERMIT TO OPERATE

405276, 410837, 474709, 474711, 474712, 512926 and 512927

PERMIT TO CONSTRUCT

470782 and 470783

COMPANY NAME: Chevron Products Company

MAILING ADDRESS: P.O. Box 97
El Segundo, CA 90245

EQUIPMENT LOCATION: 324 W. El Segundo Blvd.
El Segundo, CA 90245

PRO PROJECT OVERVIEW:

Chevron Products Company is proposing the Product Reliability and Optimization (PRO) Project at the El Segundo Refinery. The purpose of this project is to increase the reliability, energy efficiency, and capacity of specific existing processing equipment; allow the processing of a wider range of crude oils; and reduce potential atmospheric emissions from some existing pressure relief devices. The proposed project includes:

- Construction of three (3) new domed external floating roof (EFR) tanks;
- Construction, removal, and modification of process equipment in the Alkylation Feed Fractionation Unit, Fluidized Catalytic Cracking Unit (FCCU), FCCU Gasoline Splitter Unit, Isomax Hydrocracking Unit, and Vacuum Residuum Desulfurization Unit;
- Construction of a new Sour Water Stripper and Sulfur Recovery Unit with Tail Gas Treatment Unit and Incinerator for removal and recovery of additional sulfur;
- Construction of a new Pressure Swing Adsorber Unit for recovery of additional hydrogen;
- Construction of a new LPG sphere and addition of a new LPG railcar loading arm at an existing loading rack;
- Construction of a new Vapor Recovery System (VRS) and Emergency Flare;
- Connection of some existing pressure relief devices to the new VRS;
- Construction of a new Cogeneration Unit with Air Pollution Control System for production of additional electricity and development of a New Source Review PM10 Cap for the Cogen Trains A, B, & D and the Auxiliary Boiler; and
- Installation of Low-NOx burners on four existing heaters.

The applications submitted for the PRO Project are summarized in the following table, which contains a column that specifies the processing status for each application. As seen in the table, the permits for this project are being issued in batches.

Applications Submitted for the PRO Project

Date Submitted	Equipment	Appl. Type (1)	Appl. No.	Status
3/2/07	Construct Domed EFR Tank No. 447	10	466150	Batch No. 1: Permits issued May 9, 2008. (Tank Nos. 303 & 447 were not constructed)
4/5/07	Construct Domed EFR Tank No. 302	10	467544	
4/5/07	Construct Domed EFR Tank No. 303	10	467547	
6/11/07 2/26/08 2/26/08	Modify Fluidized Catalytic Cracking Unit (FCCU). Also evaluate impact on the FCCU SCR and ESP.	50	470768 478517 479168	
3/2/07	Modify Isomax Hydrocracking Unit	50	466149	Batch No. 2: Permits Issued July 9, 2009
5/7/08 5/7/08	Connect new PRDs to Isomax Vapor Recovery System and Flare.	50	485806 485807	
3/26/07	Construct Sour Water Stripper	10	467141	Batch No. 3: Permits Issued May 14, 2010
6/13/07 6/13/07 3/28/08 5/22/09	Construct Sulfur Recovery Unit No. 73 with Tail Gas Treatment Unit, Incinerator, and SOx Scrubber	10	470738 470739 480558 498947	
5/7/08 5/7/08	Connect new PRDs to Refinery Blowdown Gas Recovery System & LSFO Flare.	50	482504 482505	
6/09/09 6/09/09 6/09/09	Add NSPS Subpart Ja Applicability to SRU Nos. 10, 20, and 70.	60	499500 499877 499878	
6/12/07 6/12/07	Construct Cogeneration D Train and Associated Air Pollution Control System	10	470782 470783	Proposed Batch No. 4
 10/17/07 10/17/07 10/17/07	Change of Permit Condition for: Cogen A Train Cogen B Train Auxiliary Boiler	 60 60 60	 474709 474711 474712	
4/13/10	Construct Domed EFR Tank No. 303	10	509856	Proposed Batch No. 5
5/25/10	Construct Domed EFR Tank No. 304	10	511144	
3/2/07	Construct No. 2 Crude Unit Flare and Vapor Recovery System (VRS)	10	466152 466151	Applications on hold at Chevron's request pending their internal project review
 6/1/07 6/1/07 6/1/07 12/6/07	Connect existing PRVs to new Flare/VRS: No. 2 Crude Unit No. 2 Resid Stripper Merox Plant Waste Gas Compressors K450A/B	 50 50 50 50	 469934 469936 469935 476228	
4/26/07	Construct LPG Tank No. 722	10	468538	
4/26/07	Add Loading Arm to LPG Loading Rack	50	468539	
6/11/07	Modify FCCU Gasoline Splitter Unit	50	470854	
12/6/07	Construct Pressure Swing Absorption Unit	10	476354	
5/21/07	Modify Alkylation Feed Fractionation Unit	50	469562	
3/26/07	Modify Vacuum Resid Desulfurizer Unit	50	467140	
3/18/08	Install Low NOx Burners on Isomax Heaters F510-540	50	479353,479354 479355,479356	

(1) Appl. Type: 10 = New Construct; 50 = Alteration of Existing Permit Unit; 60 = Change of Condition

BACKGROUND/SUMMARY

As part of their PRO Project, Chevron is proposing to install a new cogeneration train to supplement three existing cogeneration units. The proposed Cogeneration Train D will provide the power needs of proposed PRO Project equipment and make the refinery more power self sufficient. The refinery is current dependent on the electrical grid for some of its power. The new cogeneration unit will lessen Chevron dependency on the electrical grid to improve the reliability of the power supply for the refinery. Improved reliability of the power supply reduces the risk of refinery upsets due to loss of power.

The cogeneration unit will include a combustion gas turbine (CGT), heat recovery steam generator (HRSG), and back-pressure steam turbine generator. The total gross power output of the turbines is 46.2 MW at ISO conditions. The proposed CGT will burn natural gas while duct burners in the HRSG will burn natural gas and/or refinery fuel gas. Chevron has also submitted change of condition applications for the purpose of combining the existing individual New Source Review (NSR) PM10 emission limits for the Cogen Train A, Cogen Train B, and Auxiliary Boiler into a combined PM10 emission limit that covers these three existing units as well as the proposed Cogen D Train.

This engineering evaluation also includes analysis of some outstanding modification and change of condition requests for the Cogen Trains (A, B, and C) and their air pollution control systems (APCS). The table below contains a summary of these change of condition and modification applications. The consolidated requests for each of the existing cogens and APCSs will be evaluated under the most recent application submitted.

Summary of Outstanding Change of Condition and Modification Appls. for the Existing Cogen Units

Equipment	Appl. Number	Submittal Date	Notes
Cogen A	357703	7/30/99	To be cancelled
	405270	8/09/02	To be cancelled
	410838	1/15/03	To be cancelled and consolidated request processed under AN 474709
Cogen A SCR	357704	7/30/99	To be cancelled
	405273	8/09/02	To be cancelled
	512926	7/27/10	Process consolidated request.
Cogen B	405271	8/09/02	To be cancelled
	410839	1/15/03	To be cancelled and consolidated request processed under AN 474711.
Cogen B SCR	357706	7/30/99	To be cancelled
	405275	8/09/02	To be cancelled
	512927	7/27/10	Process consolidated request.
Cogen C	410837	1/15/03	Process consolidated request.
Cogen C SCR	357715	7/30/99	To be cancelled
	405276	8/09/02	Process consolidated request.

The consolidated requests are summarized below.

Cogen A, B, and C Turbines

- Specify a 60-minute averaging period for the 10 ppmv CO and 9 ppmv NOx limits. [Cogen A; Cogen B; Cogen C]

- Condition D12.6: Delete this condition, which requires a CMS to indicate and record the steam-to-fuel ratio. [Cogen A; Cogen B; Cogen C]

- Condition D12.6: If condition D12.6 cannot be removed from the permit, change the calibration requirement for the steam-to-fuel ratio CMS from monthly to annual. [Cogen A; Cogen B; Cogen C]

- Condition E73.2: Replace the word "turbine" with "SCR" and place the condition on the SCRs. [Cogen A; Cogen B; Cogen C].

- Specify a 3 hour averaging period for the 100 ppm fuel total sulfur limit [Cogen C only]

- Tag existing source test condition D28.11, which is tagged to the Cogen A and B turbines to the Cogen C turbine. [Cogen C]

Cogen A, B, and C SCRs

- Specify a 60-minute averaging period for the 20 ppmv NH3 emission limit. [SCRs serving Cogen A, Cogen B, and Cogen C]

- Modify Condition No. D12.2, which requires a continuous monitoring system (CMS) and recorder for the ammonia injection rate-to-emitted NOx ratio. [SCRs serving Cogen A, Cogen B, and Cogen C]

- Revise Condition D28.1 from quarterly NH3 source testing to annual source testing. [SCRs serving Cogen A and Cogen B]

- Chevron replaced the SCR catalyst for Cogen Trains A and B with a different catalyst than is currently permitted without obtaining a permit to construct to install the new catalyst. Chevron has submitted an application for a permit to operate for the new catalyst. As required by Rule 301(c)(1)(D), Chevron submitted an additional 50% fee for changing the catalyst without obtaining a permit to construct.

EQUIPMENT DESCRIPTION:

Permits to operate will be issued for the existing cogeneration units, Auxiliary Boiler and associated APCSs in Section D of Chevron's RECLAIM/Title V Facility Permit. Permits to construct will be issued for the proposed Cogen Train D and associated APCS in Section H of the RECLAIM/Title V Facility Permit. The proposed permit pages for each of these permits are contained in this section. In these proposed permit pages, new text is indicated by underline and deleted text is indicated by strikeout. Copies of the applicable pages from Chevron's current Title V/RECLAIM Facility Permit (FP) are contained in the engineering file for the Auxiliary Boiler, existing cogeneration units and APCSs. For all of these existing permit units, a permit to construct in Section H of Chevron's Title V/RECLAIM FP is acting as the temporary permit to operate.

Section D: Facility Description and Equipment Specific Conditions

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 1: COGENERATION A TRAIN					~~S7.2~~
GAS TURBINE, NO. 1, BUTANE, NATURAL GAS, PROPANE, PENTANE , GENERAL ELECTRIC MODEL NO. PG6531B (FRAME 6), ~~INCLUDES PENTANE FUEL~~, WITH STEAM OR WATER INJECTION, ~~616~~ 560 MMBTU/HR (HHV): GENERATOR, ELECTRIC, 46 MW **A/N: ~~403042~~ 474709**	D2198	~~D2199~~ C2210 C2211	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO**: 2,000 PPMV (5) [RULE 407]; **CO**: 10 PPMV (4) [RULE 1303 BACT]; **NOx**: 9 PPMV (4) [RULE 2005; 4-20-2001]; **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 475]; **PM**: 11 LBS/HR (5B) [RULE 475]	A63.10, A63.11, A63.31, A99.4, A99.5, A195.23, A195.24, A327.1, B61.6, B61.7, C1.82, C1.49, D12.6, D28.13, D29.5, D82.2, D82.3, D90.20, D90.23, E54.7, E73.1, E73.2, H23.27, H23.28, K40.5, K67.2
NOTE: 616 MMBtu/hr is the total heat input limit for the combined turbine and duct burner. It is replaced by the maximum capacity of 560 MMBtu/hr. Condition C1.149, which limits the combined heat input of the turbine and duct burner to 616 MMBtu/hr, has been added to the permit. Same applies for the Cogen B Train.					
BURNER, DUCT NO. 1, NATURAL GAS, REFINERY GAS, COEN, LOW NOX TYPE, 119.7 MMBTU/HR (LHV) **A/N: ~~403042~~ 474709**	D2199	~~D2198~~ ~~D2206~~ C2210 C2211	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO**: 2,000 PPMV (5) [RULE 407]; **NOx**: 0.2 LBS/MMBTU (8A) [40CFR 60 SUBPART Db, 10-01-2001]; **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 476]; **PM**: 11 LBS/HR (5B) [RULE 476]	A327.2, B61.6, C1.149, D28.13, D29.5, D90.20, H23.26, K67.2
COMPRESSOR, FUEL BOOSTER, K-3100, NATURAL GAS, COMMON TO COGENS A & B **A/N: ~~403042~~ 474709**	D2200				
COMPRESSOR, FUEL BOOSTER, K-3110, NATURAL GAS, COMMON TO COGENS A & B **A/N: ~~403042~~ 474709**	D2201				
BOILER, WASTE HEAT RECOVERY, NO. 1, STRUTHER WELLS, UNFIRED TUBE TYPE, 264,000 LB PER HOUR, 850 PSIA, 720 DEG F STEAM **A/N: ~~403042~~ 474709**	D2206	~~D2199~~ ~~C2211~~			

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
KNOCK OUT POT, LPG RELIEF SYSTEM, V-3670, COMMON TO COGEN TRAINS A & B, LENGTH: 16 FT; DIAMETER: 8 FT **A/N: ~~403042~~ 474709**	D3479				
DRUM, LPG RECIRCULATION SURGE, V-3990, COMMON TO COGEN TRAINS A & B, LENGTH: 8 FT; DIAMETER: 4 FT **A/N: ~~403042~~ 474709**	D3480				
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~403042~~ 474709**	D3671				H23.3
DRUM, LPG KNOCKOUT, V-3140, COMMON TO COGEN TRAINS A & B, LENGTH: 10 FT; DIAMETER: 4 FT **A/N: ~~403042~~ 474709**	D3730				
HEAT EXCHANGER, E-3140, PENTANE VAPORIZER, STEAM HEATED, PENTANE, 6.95 MMBTU/HR DUTY, COMMON TO COGEN TRAINS A & B **A/N: ~~403042~~ 474709**	D3801				

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 2: COGENERATION TRAIN B					~~S7.2~~
GAS TURBINE, NO. 2, BUTANE, NATURAL GAS, PROPANE, PENTANE, GENERAL ELECTRIC MODEL NO. PG6531B (FRAME 6), ~~INCLUDES PENTANE FUEL,~~ WITH STEAM OR WATER INJECTION, ~~616~~ 560 MMBTU/HR (HHV): GENERATOR, ELECTRIC, 46 MW **A/N: ~~403043~~ 474711**	D2207	~~D2208~~ C2213 C2214	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO**: 2,000 PPMV (5) [RULE 407]; **CO**: 10 PPMV (4) [RULE 1303 BACT]; **NOx**: 9 PPMV (4) [RULE 2005; 4-20-2001] **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 475]; **PM**: 11 LBS/HR (5B) [RULE 475]	A63.10, A63.12, A63.31, A99.4, A99.5, A195.23, A195.24, A327.1, B61.6, B61.7, C1.82, C1.149, D12.6, D28.13, D29.5, D82.2, D82.3, D90.20, D90.23, E54.8, E73.1, E73.2, H23.27, H23.28, K40.5, K67.2
BURNER, DUCT NO. 2, NATURAL GAS, REFINERY GAS, COEN, LOW NOX TYPE, 119.7 MMBTU/HR (LHV)	D2208	~~D2207~~ ~~D2209~~ C2213 C2214	NOx: MAJOR SOURCE; SOX:	**CO**: 2,000 PPMV (5) [RULE 407]; **NOx**: 0.2 LBS/MMBTU (8A) [40CFR 60 SUBPART Db, 10-01-	A327.2, B61.6, C1.149, D28.13, D29.5, D90.20, H23.26, K67.2

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
A/N: ~~403043~~ 474711			MAJOR SOURCE	2001]; **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 476]; **PM**: 11 LBS/HR (5B) [RULE 476]	
COMPRESSOR, FUEL BOOSTER, K-3100, NATURAL GAS, COMMON TO COGENS A & B **A/N: ~~403042~~ 474709**	D2200				
COMPRESSOR, FUEL BOOSTER, K-3110, NATURAL GAS, COMMON TO COGENS A & B **A/N: ~~403042~~ 474709**	D2201				
KNOCK OUT POT, LPG RELIEF SYSTEM, V-3670, COMMON TO COGEN TRAINS A & B, LENGTH: 16 FT; DIAMETER: 8 FT **A/N: ~~403042~~ 474709**	D3479				
DRUM, LPG RECIRCULATION SURGE, V-3990, COMMON TO COGEN TRAINS A & B, LENGTH: 8 FT; DIAMETER: 4 FT **A/N: ~~403042~~ 474709**	D3480				
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~403043~~ 474711**	D3672				H23.3
DRUM, LPG KNOCKOUT, V-3140, COMMON TO COGEN TRAINS A & B, LENGTH: 10 FT; DIAMETER: 4 FT **A/N: ~~403042~~ 474709**	D3730				
HEAT EXCHANGER, E-3140, PENTANE VAPORIZER, STEAM HEATED, PENTANE, 6.95 MMBTU/HR DUTY, COMMON TO COGEN TRAINS A & B **A/N: ~~403042~~ 474709**	D3801				

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 3: AIR POLLUTION CONTROL COGEN TRAIN A					
SELECTIVE CATALYTIC REDUCTION, REACTOR NO. ~~1-A~~ R-3300, ~~HITACHI~~ CORMETECH , ~~PLATE~~ CERAMIC HONEYCOMB TYPE OR APPROVED EQUIVALENT CATALYST, ~~2700~~ 667 CU. FT.; DEPTH ~~1~~6 FT ~~9~~ 11 IN, HEIGHT: ~~33~~30 FT 11 IN; WIDTH: ~~16~~ 13 FT ~~6~~ 11 IN WITH AMMONIA INJECTION, V-3350, AQUEOUS AMMONIA **A/ N: ~~321808~~ 512926**	C2210	~~C2211~~ D2198 D2199		**NH3:** 20 PPMV (4) [RULE : 1303(a)(1)-BACT, 5-10-1996]	A99.3, A195.25, D12.2, D12.3, D12.11, ~~D28.1~~, D29.4, E193.5, K40.5,
CO OXIDATION CATALYST, NO. ~~1-B~~ R-3350, DEPTH: 12 FT, 117. 6 CU FT CATALYST, WIDTH: 13 FT; HEIGHT: 28 FT 9 IN **A/ N: ~~321808~~ 512926**	C2211	~~D2206~~ ~~C2210~~ D2198 D2199			D12.4, D12.13
BLOWER, DILUTION (2), K-3310, WITH MOTOR DRIVE, ONE UNIT STANDBY **A/ N: ~~321808~~ 512926**	D3481				
BLOWER, DILUTION (2), K-3320, WITH MOTOR DRIVE, ONE UNIT STANDBY **A/ N: ~~321808~~ 512926**	D3482				

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 4: AIR POLLUTION CONTROL COGEN TRAIN B					
SELECTIVE CATALYTIC REDUCTION, REACTOR NO. ~~2-A~~ R-3400, ~~HITACHI~~ CORMETECH , ~~PLATE~~ CERAMIC HONEYCOMB TYPE OR APPROVED EQUIVALENT CATALYST, ~~2700~~ 667 CU. FT.; DEPTH ~~1~~6 FT ~~9~~ 11 IN, HEIGHT: ~~33~~30 FT 11 IN; WIDTH: ~~16~~ 13 FT ~~6~~ 11 IN WITH AMMONIA INJECTION, V-3450, AQUEOUS AMMONIA **A/ N: ~~321809~~ 512927**	C2213	~~C2214~~ D2207 D2208		**NH3:** 20 PPMV (4) [RULE : 1303(a)(1)-BACT, 5-10-1996]	A99.3, A195.25, D12.2, D12.3, D12. 11, ~~D28.1~~, D29.4, E193.5, K40.5

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
CO OXIDATION CATALYST, NO. ~~2-B~~ R-3450, DEPTH: 12 FT, 117. 6 CU FT CATALYST, WIDTH: 13 FT; HEIGHT: 28 FT 9 IN **A/ N: ~~321809~~ 512927**	C2214	~~D2209~~ ~~C2213~~ D2207 D2208			D12.4, D12.13
BLOWER, DILUTION (2), K-3410, WITH MOTOR DRIVE, ONE UNIT STANDBY **A/ N: ~~321809~~ 512927**	D3483				
BLOWER, DILUTION (2), K-3420, WITH MOTOR DRIVE, ONE UNIT STANDBY **A/ N: ~~321809~~ 512927**	D3484				

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 5: COGENERATION TRAIN C					
GAS TURBINE, NO. 3, TPG-3600, NATURAL GAS, GENERAL ELECTRIC MODEL NO. PG-6541B (FRAME 6), WITH 600-H. P. STARTUP MTR, WITH STEAM OR WATER INJECTION, 506 MMBTU/ HR (HHV) WITH GENERATOR, ELECTRIC, 46 MW **A/ N: ~~403044~~ 410837**	D3053	C3058 C3059	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	**CO:** 2000 PPMV (5) [RULE 407, 4-2-1982] ; **CO:** 10 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996] ; **NOX:** 9 PPMV (4) [RULE 2005, 4-20-2001] **PM:** 0. 1 GRAINS/ SCF (5) [RULE 409, 8-7-1981] ; **PM:** 0. 01 GRAINS/ 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]	A63.10, A99.4, A99.5, A195.23, A195.24, A327.1, ~~B59.1~~, B61.7, C1.82, D12.6, ~~D28.2~~, D28.11, D82.2, D82.3, D90.23, E54.1, E73.1, E73.2, H23.27, K40.5, K67.2
BURNER, DUCT, NO. 3, NATURAL GAS, REFINERY GAS, COEN, LO NOX TYPE, 120 MMBTU/ HR (LHV) **A/ N: ~~403044~~ 410837**	D3054	C3058 C3059	NOX: MAJOR SOURCE**; SOX: MAJOR SOURCE**	**CO:** 2000 PPMV (5) [RULE 407, 4-2-1982] ; **NOX:** 0. 2 LBS/ MMBTU (8) [40CFR 60 Subpart Db, 10-1-2001] ; **PM:** 0. 01 GRAINS/ SCF (5A) [RULE 476, 10-8-1976] **PM:** 11 LBS/ HR (5B) [RULE 476, 10-8-1976] ; **PM:** 0. 1 GRAINS/ SCF (5) [RULE 409, 8-7-1981]	A327.2, B61.2, B61.6, D28.11, D90.20, H23.26
GENERATOR, STEAM HEAT RECOVERY, E-3600, DELTAK, UNFIRED, TUBE TYPE **A/ N: ~~403044~~ 410837**	D3055				

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
KNOCK OUT POT, V-4560, FUEL GAS, HEIGHT: 9 FT; DIAMETER: 4 FT 6 IN **A/ N: ~~403044~~ <u>410837</u>**	D3056				
VESSEL, SEPARATOR, V-3987 **A/ N: ~~403044~~ <u>410837</u>**	D3057				
FUGITIVE EMISSIONS, MISCELLANEOUS **A/ N: ~~403044~~ <u>410837</u>**	D3673				H23. 3

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 6: AIR POLLUTION CONTROL COGEN TRAIN C					
SELECTIVE CATALYTIC REDUCTION, R-3600, DEPTH: 2 FT, CERAMIC HONEYCOMB TYPE <u>OR APPROVED EQUIVALENT CATALYST</u>, 950 CU. FT. ; HEIGHT: 50 FT; WIDTH: 14 FT 7 IN WITH AMMONIA INJECTION, V-3610, AQUEOUS AMMONIA **A/ N: ~~296431~~ <u>405276</u>**	C3058	D3053 D3054 S3068		**NH3:** 20 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996]	A99.3, <u>A195.25</u>, D12.2, D12.3, D12.11, D29.4, <u>E193.5</u>, <u>K40.5</u>
REACTOR, CARBON MONOXIDE CATALYTIC CONVERTER, R-3650, 74 CU FT ~~CATALYST, WITH CATALYTIC REDUCTION~~, DEPTH: 3 IN, WIDTH: 10 FT 1 IN; HEIGHT: 53 FT 8 IN **A/ N: ~~296431~~ <u>405276</u>**	C3059	D3053 D3054			D12.4, D12.13
STACK **A/ N: ~~296431~~ <u>405276</u>**	S3068	C3058			

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 18: STEAM GENERATION					
SYSTEM 1: AUXILIARY BOILER					
BOILER, E-3500, AUXILIARY BOILER NATURAL GAS, REFINERY GAS, COMBUSTION ENG, MODEL 12F-40-A16~~, WITH LOW NOX BURNER~~, 342 MMBTU/HR WITH BURNER, NATURAL GAS, REFINERY GAS, COEN, MODEL CPF-37-1/2, 2 GAS BURNERS, LOW NOX BURNER, ~~342 MMBTU/HR~~ **A/N: ~~278188~~ 474712**	D2216	C2217	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO**: 2000 PPMV (5) [RULE 407,4-2-1982] ; **NOX**: 0.2 LBS/MMBTU (8) [40CFR 60 Subpart Db,11-16-2006] ; **PM**: 0.01 GRAINS/SCF (5A) [RULE 476,10-8-1976] **PM**: 11 LBS/HR (5B) [RULE 476,10-8-1976] ; **PM**: 0.1 GRAINS/SCF (5) [RULE 409,8-7-1981]	A63.25, A63.31, A327.2, B61.6, ~~D28.11~~, D28.13, D29.5, D82.4, D90.20, H23.26, K40.5

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
SYSTEM 2: AUXILIARY BOILER APC					
SELECTIVE CATALYTIC REDUCTION, R-3500, MITSUBISHI HEAVY INDUSTRIES OR APPROVED EQUIVALENT CATALYST WITH AMMONIA INJECTION, V-3550, AQUEOUS AMMONIA **A/N: 321806**	C2217	D2216 S3476		NH3: 20 PPMV (4) [RULE 1303(a)(1)-BACT,5-10-1996]	A195.26, D29.4, D94.1, E71.1, E193.5, K40.5
STACK **A/N: 321806**	S3476	C2217			

Section H: Permit to Construct and Temporary Permit to Operate

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 7: COGENERATION TRAIN D					S7.4, S31.20
GAS TURBINE, No. 4, NATURAL GAS, GENERAL ELECTRIC MODEL NO. PG6581 (FRAME 6B), 508.7 MMBTU/HR (HHV) DRY LOW NOX COMBUSTOR GENERATOR, ELECTRIC, GE MODEL PG-3700, 43.75 MW **A/N: 470782**	D4354	C4360 C4361	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO:** 2,000 PPMV (5) [RULE 407]; **CO:** 2 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996] [RULE 1703(a)(2) – PSD - BACT]; **NOx**: 2 PPMV (4) [RULE 2005; 4-20-2001]; **NOx**: 25 PPMV (8) [40CFR 60 SUBPART KKKK, 7-06-2006]; **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 475]; **PM**: 11 LBS/HR (5B) [RULE 475]; **SO2**: 0.06 LBS/MMBTU (8A) [40CFR	A63.30, A63.31, A63.32, A99.11, A99.12, A99.13, A99.14, A99.15, A195.19, A195.20, A195.21, A327.1, C1.147, D29.12, D82.13, D82.14, E73.2, H23.27, H23.48, I296.1, K40.5, K67.74

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
				60 SUBPART KKKK, 7-06-2006]; VOC: 2 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996]	
BURNER, DUCT BURNER NO. 4, NATURAL GAS, REFINERY GAS, COEN, LOW NOX TYPE, 132 MMBTU/HR (HHV) **A/N: 470782**	D4355	C4360 C4361	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO**: 2,000 PPMV (5) [RULE 407]; **NOx**: 25 PPMV (8) [40CFR 60 SUBPART KKKK, 7-06-2006]; **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 476]; **PM**: 11 LBS/HR (5B) [RULE 476], **SO2**: 0.06 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK, 7-06-2006];	A99.14, A99.15, A327.2, B61.12, B61.13, C1.148, D29.12, D90.40, D90.41, H23.48, H23.49, I296.1, K67.74
COMPRESSOR, FUEL BOOSTER, K-3120, NATURAL GAS, **A/N: 470782**	D4356				
TURBINE, STEAM, TPG-3750 GENERATOR, ELECTRIC, PG-3750, 4.0 MW **A/N: 470782**	D4357				
BOILER, HEAT RECOVERY STEAM GENERATOR, E-3700, UNFIRED TUBE TYPE **A/N: 470782**	D4358				
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: 470782**	D4359				H23.3

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 8: AIR POLLUTION CONTROL COGEN TRAIN D					S7.4
REACTOR, CARBON MONOXIDE OXIDATION CATALYST SYSTEM, R-3750, BASF OR APPROVED EQUIVALENT SYSTEM, 100 CU FT; DEPTH: 2.6 IN; WIDTH: 11 FT; HEIGHT: 56 FT **A/ N: 470783**	C4360	D4354 D4355			D12.4, D12.13, E193.5

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
SELECTIVE CATALYTIC REDUCTION, R-3700, CORMETECH OR APPROVED EQUIVALENT SYSTEM, 300 CU. FT. DEPTH: 13.4 IN; WIDTH: 11 FT; HEIGHT: 56 FT; WITH AMMONIA INJECTION GRID **A/ N: 470783**	C4361	D4354 D4355		**NH3:** 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996]	A99.16, A195.22, D12.3, D12.11, D29.13, E193.5, K40.5
AQUEOUS AMMONIA VAPORIZER, V-3710/V-3720 (ONE SPARE) **A/ N: 470783**	D4362				

System Conditions

S7.2 The following conditions shall apply to all refinery operation and related devices from this system:

The operator shall comply with all applicable mitigation measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document which is part of the AQMD Certified Final Environmental Impact Report dated 30-Nov-2001 for this facility.

[CA PRC CEQA, 11-23-1970]

[Systems subject to this condition : Process 3, System 5; Process 4, System 3 , 4; Process 7, System 7; Process 8, System 8; Process 14, System 28; Process 16, System 8; ~~**Process 17, System 1 , 2**~~]

There are no ongoing mitigation measures specified in this document.

S7.4 The following conditions shall apply to all refinery operation and related devices from this system:

The operator shall comply with all applicable mitigation measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document which is part of the AQMD Certified Final Environmental Impact Report dated 09-May-2008 for this facility.

The operator shall maintain records in a manner approved by the District , to demonstrate compliance with the applicable measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document.

[CA PRC CEQA, 11-23-1970]

[Systems subject to this condition: Process 3, System 1; Process 7, System 4; **Process 17, System 7, 8**; Process 20, System 4, 31]

S11.1 The operator shall comply with all applicable mitigation measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document which is part of the AQMD Certified Final Environmental Impact Report dated 09-may-1995 for this facility.

This condition shall only apply to equipment listed in Section H of this facility permit.

[CA PRC CEQA, 11-23-1970]

[Systems subject to this condition : Process 1, System 17; Process 4, System 3; Process 8, System 1, 5, 7; Process 9, System 2; Process 14, System 17; ~~**Process 17, System 5, 6**~~; Process 20, System 24]

There are no ongoing mitigation measures.

S31.20 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 466149, 466876, 467141, 467544, ~~and~~ 470739, <u>and 470782</u>:

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(b)(2)-Offset, 5-10-1996]

[Systems subject to this condition: Process 12, System 28; Process 13, System 11; Process 16, System 10; <u>**Process 17, System 7**</u>; Process 20, System 37]

Device Conditions

A63.10 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
~~Total hydrocarbon~~ <u>VOC</u>	Less than or equal to 86 lbs in any one day
CO	Less than or equal to 160 lbs in any one day
PM10	Less than or equal to 174 lbs in any one day

For the purposes of this condition, the limit(s) shall be based on the total combined emissions from equipment (gas turbine and its duct burner).

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

[Devices subject to this condition: **D2198, D2207, D3053**]

A63.11 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
NOx	Less than or equal to 46.42 tons in any one year
SOx	Less than or equal to 10.75 tons in any one year

For the purpose of demonstrating the exemption from PSD requirements, the operator shall calculate the annual NOx and SOx emissions by using daily emission data reported to the AQMD pursuant to Reg. XX.

[RULE 1703 - PSD Analysis, 10-7-1988; 40CFR 52. 21 - PSD, 6-19-1978]

[Devices subject to this condition: **D2198**]

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

Contaminant	Emissions Limit
NOx	Less than or equal to 48.44 tons in any one year
SOx	Less than or equal to 10.87 tons in any one year

For the purpose of demonstrating the exemption from PSD requirements, the operator shall calculate the annual NOx and SOx emissions by using daily emission data reported to the AQMD pursuant to Reg. XX.

[RULE 1703 - PSD Analysis, 10-7-1988; 40CFR 52. 21 - PSD, 6-19-1978]

[Devices subject to this condition: **D2207**]

A63.25 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
~~ROG~~ VOC	Less than or equal to 95 lbs in any one day
CO	Less than or equal to 690 lbs in any one day
PM10	Less than or equal to 230 lbs in any one day

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

[Devices subject to this condition: **D2216**]

A63.30 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
VOC	Less than or equal to 42.2 lbs in any one day

The operator shall calculate the emission limit(s) by using monthly fuel use data and the following emission factors: 2.73 lbs/MMscf for normal operation; 5.7 lb/start-up and 26.9 lb/shutdown.

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

[Devices subject to this condition: **D4354**]

A63.31 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
PM10	Less than or equal to 577 lbs in any one day

For the purpose of this condition, the limit shall be based on the combined total emissions from the Cogeneration A Train (D2198 and D2199 in Process 17, System 1), Cogeneration B Train (D2207 and D2208 in Process 17, System 2), Cogeneration D Train (D4354 and D4355 in Process 17, System 5) and the Auxiliary Boiler (D2216 in Process 18, System 1).

The operator shall initially calculate the daily PM10 emissions using the daily fuel use data for each combustion unit (D2198, D2199, D2207, D2208, D2216, D4354 and D4355), the high heating value of the fuel burned in each combustion unit, and the following emissions factors: Cogeneration Train A – 0.0098 lb/MMBtu (HHV), Cogeneration Train B – 0.0083 lb/MMBtu (HHV), Cogeneration Train D - 0.0071 lb/MMBtu (HHV); Auxiliary Boiler (D2216) – 0.0086 lb/MMBtu (HHV).

The PM10 emission factor for the Cogen Trains A and B and the Auxiliary Boiler shall be revised annually based on results of individual PM10 source tests performed as specified in permit condition D29.5. The PM10 emission factor shall be calculated as the average emission rate in lb/MMBtu/hr for all valid source test runs during the annual source test.

The PM10 emission factor for the Cogen Train D shall be revised initially and annually, thereafter, based on results of PM10 source tests performed as specified in permit condition D29.12. The PM10 emission factor shall be calculated as the average emission rate in lb/MMBtu for all valid source test runs during each individual source test.

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

[Devices subject to this condition: **D2198, D2207, D2216, D4354**]

A63.32 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
PM10	Less than or equal to 113 lbs in any one day

The operator shall calculate the daily PM10 emissions using the daily fuel use data for the turbine (D4354) and duct burner (D4355), the high heating value of the fuel burned in each combustion unit, and an emission factor of 0.0071 lb/MMBtu.

The PM10 emission factor for the Cogen Train D shall be revised initially and annually, thereafter, based on results of PM10 source tests performed as specified in permit condition D29.12. The PM10 emission factor shall be calculated as the average emission rate in lb/MMBtu for all valid source test runs during each individual source test.

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

[Devices subject to this condition: **D4354**]

A99.3 The 20 PPM NH3 emission limit(s) shall not apply during startup and shutdown.

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

[Devices subject to this condition: **C2210, C2213, C3058**, C3533]

A99.4 The 10 PPM CO emission limit(s) shall not apply during startup and shutdown.

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

[Devices subject to this condition: **D2198, D2207, D3053**]

A99.5 The 9 PPM NOX emission limit(s) shall not apply during startup and shutdown.

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

[Devices subject to this condition: **D2198, D2207, D3053**]

<u>**A99.11** The 2.0 PPM CO emission limit shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 166 hours. Start-up time shall not exceed 2 hours for each start-up. Shutdown periods shall not exceed 2 hours for each shutdown. The turbine shall be limited to a maximum of 12 start-ups per year with a maximum of 4 start-ups per month. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.</u>

<u>For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to CO Catalyst is below 851 degree F.</u>

<u>**[RULE 1303(a)(1)-BACT, 5-10-1996][RULE 1703(a)(2) - PSD-BACT, 10-7-1988]**</u>

<u>[Devices subject to this condition: **D4354**]</u>

<u>**A99.12** The 2 PPM NOX emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 166 hours. Start-up time shall not exceed 2 hours for each start-up. Shutdown periods shall not exceed 2 hours for each shutdown. The turbine shall be limited to a maximum of 12 start-ups per year with a maximum of 4 start-ups per month. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.</u>

<u>For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597 degree F.</u>

<u>NOx emissions shall not exceed 32.1 lb/startup and 29.5 lb/shutdown.</u>

<u>**[RULE 2005, 5-6-2005]**</u>

<u>[Devices subject to this condition: **D4354**]</u>

A99.13 The 2 PPM VOC emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 166 hours. Start-up time shall not exceed 2 hours for each start-up. Shutdown periods shall not exceed 2 hours for each shutdown. The turbine shall be limited to a maximum of 12 start-ups per year with a maximum of 4 start-ups per month. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to CO Catalyst is below 851 degree F.

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

[Devices subject to this condition: **D4354**]

A99.14 The 65.5 LB/MMSCF NOx emission factor(s) shall only apply during initial combustion gas turbine and duct burner commissioning to report RECLAIM emissions.

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

[Devices subject to this condition: D4354, D4355]

A99.15 The 8.03 LB/MMSCF NOx emission factor(s) shall only apply during the interim reporting period after initial combustion gas turbine and duct burner commissioning to report RECLAIM emission. The interim reporting shall not exceed 12 months from entry into RECLAIM.

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

[Devices subject to this condition: **D4354, D4355**]

A99.16 The 5 PPM NH3 emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 166 hours. Start-up time shall not exceed 2 hours for each start-up. Shutdown periods shall not exceed 2 hours for each shutdown. The turbine shall be limited to a maximum of 12 start-ups per year with a maximum of 4 start-ups per month. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597 degree 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 597°F.

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

[Devices subject to this condition: **C4361**]

A195.19 The 2 PPMV NOx emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

[Rule 2005, 5-6-2005]

[Devices subject to this condition: **D4354**]

A195.20 The 2 PPMV CO emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

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

[Devices subject to this condition: **D4354**]

A195.21 The 2 PPMV VOC emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

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

[Devices subject to this condition: **D4354**]

A195.22 The 5 PPMV NH3 emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH3 (ppmv) = [a–b*c/1EE+06]*1EE+06/b

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

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

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

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

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

[Devices subject to this condition: **C4361**]

A195.23 The 10 PPMV CO emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

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

[Devices subject to this condition: **D2198, D2207, D3053**]

A195.24 The 9 PPMV NOx emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

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

[Devices subject to this condition: **D2198, D2207, D3053**]

A195.25 The 20 PPMV NH3 emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

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

[Devices subject to this condition: **C2210, C2213, C3058**]

A195.26 The 20 PPMV NH3 emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH3 (ppmv) = [a–b*c/1EE+06]*1EE+06/b

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

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated by October 31, 2011.

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

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

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

[Devices subject to this condition: **C2217**]

A327.1 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: **D2198, D2207, D3053, D4354**]

A327.2 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: **D2199, D2208**, **D2216**, **D3054, D4355**]

~~**B59.1** The operator shall only use the following material(s) in this device:~~

~~Natural Gas~~

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

~~[Devices subject to this condition: **D3053**]~~

Note: This condition is redundant with the equipment description for this turbine (D3053). The equipment description contains an enforceable limitation to the combustion of natural gas only since natural gas is the only fuel included in the description.

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

Compound	ppm by volume
Total Sulfur as H2S greater than	100

The 100 ppmv total sulfur limit shall be based on a rolling 1-hour averaging period.

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

[Devices subject to this condition: **D3054**]

B61.6 The operator shall not use fuel gas, except uncombined natural gas, containing the following specified compounds:

Compound	ppm by volume
H2S greater than	160

The H2S concentration limit shall be based on a rolling 3-hour averaging period

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

[Devices subject to this condition: D471, D472, D473, D641, D643, **D2198, D2199, D2207, D2208, D2216**, D3031, **D3054**, C3148, D3530, D3695, D3778, D3973]

B61.7 The operator shall not use any fuel containing the following specified compounds:

Compound	weight percent
Sulfur greater than	0.8

[40CFR 60SubpartGG, 7-8-2004]

[Devices subject to this condition: **D2198, D2207, D3053**]

B61.12 The operator shall not use fuel gas containing the following specified compounds:

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

The 40 ppm limit shall be based on a rolling 1-hour averaging period

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

For all but 72 hours per year, the total reduced sulfur concentration of the refinery fuel gas shall be measured before blending with natural gas. The total reduced sulfur of the refinery fuel gas may be measured after blending with natural gas for a maximum of 72 hours per year.

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

[Rule 2005, 5-6-2005]]

[Devices subject to this condition: **D4355**]

B61.13 The operator shall not use fuel gas containing the following specified compounds:

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

The 162 ppm limit shall be based on a rolling 3-hour averaging period

The 60 ppm limit shall be based on a rolling 365 successive calendar day rolling average

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

[Devices subject to this condition : **D4355**]

C1.82 The operator shall limit the duration of startup or shutdown to no more than 6 hour(s).

[**RULE 2012, 1-7-2005**]

[Devices subject to this condition: **D2198, D2207, D3053**]

C1.147 The operator shall limit the firing rate to no more than 508.7 MM Btu per hour.

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

To comply with this condition, the operator shall install and maintain a(n) continuous monitoring system that includes a continuous fuel flow meter and continuous or semi-continuous HHV analyzer for the natural gas fed to the turbine.

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

This limit shall be based on a rolling 1-hr averaging period.

[**RULE 1303(b)(2)-Offset, 5-10-1996, Rule 2005, 5-6-2005**]

[Devices subject to this condition : **D4354**]

C1.148 The operator shall limit the firing rate to no more than 132 MM Btu per hour.

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

To comply with this condition, the operator shall install and maintain a(n) continuous monitoring system that includes a continuous fuel flow meter and continuous or semi-continuous HHV analyzer for both the natural gas and refinery gas streams fed to the duct burner(s).

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

This limit shall be based on a rolling 1-hr averaging period.

[**RULE 1303(b)(2)-Offset, 5-10-1996, Rule 2005, 5-6-2005**]

[Devices subject to this condition : **D4355**]

C1.149 The operator shall limit the firing rate to no more than 616 MM Btu per hour.

For the purpose of this condition, firing rate shall be defined as the combined energy or heat input to the turbine and duct burner based on the higher heating valve (HHV) of the fuel used.

To comply with this condition, the operator shall install and maintain a(n) continuous monitoring system that includes a continuous fuel flow meter and continuous or semi-continuous HHV analyzer for the fuel(s) fed to the turbine and duct burner.

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

This limit shall be based on a rolling 1-hr averaging period.

[**RULE 1303(b)(2)-Offset, 5-10-1996, Rule 2005, 5-6-2005**]

[Devices subject to this condition: **D2198, D2199, D2207, D2208**]

D12.2 The operator shall install and maintain a(n) continuous monitoring system to accurately indicate the ~~ammonia-to-emitted NOx mole ratio at the gas turbine stack outlet~~ ammonia injection rate of the ammonia injection system.

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

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

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

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

[Devices subject to this condition: **C2210, C2213, C3058**]

D12.3 The operator shall install and maintain a(n) differential pressure gauge to accurately indicate the differential pressure across the SCR catalyst beds in inches water column.

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

The measuring device or gauge shall be accurate to within +/- 5 percent. It shall be calibrated once every twelve months.

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

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

[Devices subject to this condition: C1967, **C2210, C2213**, **C3058**, C3533, C3696, C3780, **C4361**]

D12.4 The operator shall install and maintain a(n) differential pressure gauge to accurately indicate the differential pressure across the CO catalyst beds.

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 week and shall be calculated based upon the average of the continuous monitoring for that week.

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

[Devices subject to this condition: **C2211, C2214, C3059, C4360**]

D12.6 The operator shall install and maintain a(n) continuous monitoring system to accurately indicate the steam-to-fuel ratio in the equipment.

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

The measuring device or gauge shall be accurate to within plus or minus 5 ~~10~~ percent. It shall be calibrated once ~~a~~ every twelve 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]

[Devices subject to this condition: **D2198, D2207, D3053]**

D12.11 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]

[Devices subject to this condition: **C2210, C2213, C3058**, C3533, C3696, **C4361**]

D12.13 The operator shall install and maintain a(n) temperature reading device to accurately indicate the temperature at the inlet to the CO catalyst beds.

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]

[Devices subject to this condition: **C2211, C2214, C3059, C4360**]

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

~~The test shall be conducted at least quarterly.~~

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

~~The test shall be conducted in accordance with the SCAQMD test procedures.~~

~~The District shall be notified of the date and time of the test at least 7 days prior to the test.~~

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

~~[Devices subject to this condition: **C2210, C2213**]~~

~~**D28.2** The operator shall conduct source test(s) in accordance with the following specifications:~~

~~The test shall be conducted to determine the Acetaldehyde at the outlet.~~

~~The test shall be conducted to determine the oxygen concentration at the outlet.~~

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

~~The test shall be conducted to determine the Cadmium at the outlet.~~

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

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

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

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

~~The test shall be conducted to determine the Formaldehyde at the outlet.~~

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

~~The test shall be conducted to determine the Nickel, refinery dust at the outlet.~~

~~The test shall be conducted within 60 days after achieving maximum production rate, but no later than 180 days after initial start-up.~~

~~Source test shall be conducted when this equipment is operating at 80 percent or greater of the maximum design capacity.~~

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

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

~~[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1401, 12-7-1990]~~

~~[Devices subject to this condition: **D3053**]~~

Note: This one time source test was performed and has been deemed as acceptable by the District. A copy of the summary results and the Districts' approval of the source test is contained in the engineering file. The Cogen Train C complied with all applicable emission limits.

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

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

The test shall be conducted to determine the ROG and PM10 emissions at the outlet.

<u>The test shall be conducted when the gas turbine and its duct burner are operating at 80 percent or greater of their maximum design capacity.</u>

<u>All fuel combusted in the duct burner(s) during the source test shall be refinery fuel gas.</u>

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

[Devices subject to this condition: **~~D2216~~, D3053, <u>D3054</u>**]

D28.13 The operator shall conduct source test(s) in accordance with the following specifications:

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

The test shall be conducted to determine the ROG ~~and PM10~~ emissions at the outlet.

The test shall be conducted when ~~the gas turbine and its duct burner are~~ <u>this equipment is</u> operating at 80 percent or greater of their maximum design capacity. <u>All of the fuel combusted in the Auxiliary Boiler and in the duct burner(s) of the cogeneration units during the source test shall be refinery fuel gas.</u>

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

[Devices subject to this condition: **D2198, <u>D2199</u>, D2207, <u>D2208</u>, <u>D2216</u>**]

D29.4 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	Approved District Method(s)	District-approved averaging time	Outlet

The test(s) shall be conducted at least annually.

The District shall be notified of the date and time of the test at least 7 days prior to the test.

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

[Devices subject to this condition: **C2210, C2213, 2217, C3058]**

D29.5 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
PM10 emissions	Approved District Method	~~1 hour~~ District-approved averaging time	Stack Outlet

~~The test(s) shall be conducted within 120 days after achieving maximum production rate, but no later than 180 days after initial start-up.~~

The test shall be conducted when ~~the gas turbine and its duct burner are~~ this equipment is operating at 80 percent or greater of the maximum design capacity. All of the fuel combusted in the Auxiliary Boiler and in the duct burner(s) of the cogeneration units during the source test shall be refinery fuel gas.

At least three sample runs shall be conducted for each source test.

The test(s) shall be conducted at least annually.

The source test shall be performed within 7 days of the annual PM10 source test of the Cogeneration Train D. If the Auxiliary Boiler is not in operation at the time of the source test of the Cogeneration Trains A, B and D, a PM10 source shall be performed within 14 days of putting the Auxiliary Boiler back in operation.

The District shall be notified of the date and time of the test at least 7 days prior to the test.

Source test results shall include the following parameters: fuel gas usage of the gas turbine and duct burner, MW output, and amount of ammonia injected for NOx control.

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

[Devices subject to this condition: **D2198, D2199, D2207, D2208, D2216]**

D29.12 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test	Averaging Time	Test Location
NOx emissions	District Method 100.1	1 hour	Stack Outlet
SOx emissions	District Method 100.1 or 6.1	1 hour	Stack Outlet

CO emissions	District Method 100.1 or 10.1	1 hour	Stack Outlet
ROG emissions	District Method 25.1 or 25.3	1 hour	Stack Outlet
PM emissions	District Method 5.2	District-approved averaging time	Stack Outlet
PM10 emissions	EPA Method 201A	District-approved averaging time	Stack Outlet
Acetaldehyde and Formaldehyde	CARB method 430	District-approved averaging time	Stack Outlet
Benzene, Toluene, Ethyl benzene, and Xylene	CARB Method 410A or 410B	District-approved averaging time	Stack Outlet

The test shall be conducted when turbine and its duct burner are each operating at 80 percent or greater of their maximum design capacity. All of the fuel combusted in the duct burner(s) during the source test shall be refinery fuel gas.

The test(s) shall be conducted within 90 days after achieving maximum production rate, but no later than 180 cumulative days of operation after initial start-up.

The test shall be conducted to determine the concentration and report the mass emission rate in pounds per hour for NOx, SOx, ROG, CO, Total PM, PM10 and the following compounds: Acetaldehyde, Benzene, Formaldehyde, Toluene, Ethyl Benzene, Xylene.

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

The test shall be conducted to determine the oxygen concentration. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the electricity generation of the turbines in MW.

The test(s) shall be conducted at least annually after the initial source test for PM10, total PM, NOx, SOx, CO, and O2.

The test(s) shall be conducted at least every three years after the initial source test for ROG and O2.

The test shall be conducted for NOx, SOx and CO (for initial and subsequent testing) until their CEMS are Rule 218 or RECLAIM certified. Once certified, source test data may be substituted with CEMS data.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1401, 3-5-2005; **RULE 2005, 4-20-2001; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 407, 4-2-1982**]

[Devices subject to this condition : **D4354, D4355**]

D29.13 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 Method 207.1	District-approved averaging time	Outlet

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

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

The NOx concentration at the SCR inlet and at the stack, as determined by the CEMS, shall be continuously recorded during the source test. If the NOx CEMS are inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1.

The ammonia injection rate and the ammonia slip concentration, which is calculated per the procedure specified in condition A195.22, shall be continuously recorded during the source test.

The test shall be conducted after District approval of a source test protocol submitted in accordance with Section E- Administrative condition.

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

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

[Devices subject to this condition : **C4361**]

D82.2 The operator shall install and maintain a CEMS to measure the following parameters:

NOX concentration in ppmv

O2 concentration in ppmv

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

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

[Devices subject to this condition: **D2198, D2207, D3053**]

Note: A copy of the Districts certification letter for the subject CEMS is contained in the engineering file. A copy of the summary test results for one the semi-annual RECLAIM CEMS RATAs is also contained in the engineering file.

D82.3 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

O2 concentration in ppmv

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 407, 4-2-1982]

[Devices subject to this condition: **D2198, D2207, D3053]**

Note: A copy of the Districts certification letter for the subject CEMS is contained in the engineering file.

D82.4 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.

Oxygen concentration in percent volume

The CEMS shall be installed to continuously record the actual stack concentration and the corrected stack concentration for CO along with the stack O2 concentration. The monitoring system shall comply with the requirements of District Rule 218.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 407, 4-2-1982**]

[Devices subject to this condition: D203, **D2216**]

D82.13 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 turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up

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

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

[Devices subject to this condition: **D4354**]

D82.14 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv at the outlet of the SCR serving the equipment

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

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

[RULE 1303(a)(1)-BACT, 5-10-1996][RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: **D4354**]

D90.20 The operator shall continuously monitor the H2S concentration in fuel gases before being burned in this device according to the following specifications:

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

The operator shall 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: D471, D472, D473, D641, D643, **D2198, D2199, D2207, D2208, D2216**, D3031, **D3054**, D3530, D3695, D3973]

D90.23 The operator shall sample and analyze the total sulfur content of the natural gas burned in this turbine according to the following specifications:

The operator shall analyze once per calendar quarter.

[40CFR 60 Subpart GG, 2-24-2006]

[Devices subject to this condition: **D2198, D2207, D3053]**

D90.40 The operator shall continuously monitor the total reduced sulfur compounds calculated as H2S concentration in the fuel gases before being burned in this device and before blending with natural gas according to the following specifications:

The CEMS shall be approved by the District before the initial start-up

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

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

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

[Devices subject to this condition: **D4355**]

D90.41 The operator shall continuously monitor the H2S concentration in the fuel gases before being burned in this device according to the following specifications:

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

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

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

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

[Devices subject to this condition: **D4355**]

D94.1 The operator shall install, maintain and operate a sampling line in the exhaust duct. The sampling line shall be constructed and operated upon approval by the AQMD.

[Devices subject to this condition: **C2217**]

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

Device ID: C3058 [SELECTIVE CATALYTIC REDUCTION, R-3600, ~~DEPTH: 2 FT, CERAMIC HONEYCOMB TYPE~~]

Requirement number 1: During startups and shutdowns

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597 degree F.

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

[Devices subject to this condition: **D3053**]

E54.7 The operator is not required to vent this equipment to the following equipment if any of the requirements listed below are met:

Device ID: C2210 [SELECTIVE CATALYTIC REDUCTION, R-3300, ~~REACTOR NO. 1-A, HITACHI, DEPTH: 16 FT 9 IN, PLATE HONEYCOMB TYPE~~]

Requirement number 1: During startups and shutdowns

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597 degree F.

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

[Devices subject to this condition: **D2198**]

E54.8 The operator is not required to vent this equipment to the following equipment if any of the requirements listed below are met:

Device ID: C2213 [SELECTIVE CATALYTIC REDUCTION, R-3400, ~~REACTOR NO. 2-A, HITACHI, DEPTH: 16 FT 9 IN, PLATE HONEYCOMB TYPE~~]

Requirement number 1: During startups and shutdowns

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597 degree F.

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

[Devices subject to this condition: **D2207**]

E71.1 The operator shall not operate this equipment if the space velocity is greater than 10,800 reciprocal hours.

[Devices subject to this condition: **C2217**]

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

During startup and shutdown of the cogeneration trains.

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

[Devices subject to this condition: **D2198, D2207, D3053**]

E73.2 Notwithstanding the requirements of Section E conditions, the operator may, at his discretion, choose not to use or inject ammonia in the ~~turbine~~ SCR if any of the following requirement(s) are met:

During startup and shutdown of the cogeneration trains.

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597 degree F.

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

[Devices subject to this condition: **D2198, D2207, D3053, D4354**]

E193.5 The operator shall construct, operate, and maintain this equipment according to the following specifications:

To establish equivalency of a catalyst, the operator shall submit the following information for the catalyst to the District permitting engineer: manufacturer, description (type), configuration, dimensions (per block), number of blocks, total volume, space velocity, life, vendor performance guarantee, performance curve (versus temperature), minimum operating temperature, estimated SO_2 to SO_3

conversion, estimated NO to NO_2 conversion, and concentration of Rule 1401 TACs.

The operator shall not install and use an "equivalent" catalyst until approval is received in writing from the District.

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

[Devices subject to this condition: **C2210, C2213, C2217, C3058, C4360, C4361**]

H23.3 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, 2-6-2009**]**

[Devices subject to this condition : D3576, D3588, D3610, D3631, D3635, D3640, D3642, D3644, D3645, D3646, D3654, D3655, D3656, D3657, D3659, D3660, D3663, **D3671, D3672, D3673**, D3681, D3687, D3688, D3691, D3694, D4086, D4087, D4088, **D4359]**

H23.26 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, Subpart	J
NOx	40CFR60, Subpart	Db

[40CFR 60 Subpart Db, 11-16-2006; 40CFR 60 Subpart J, 6-24-2008]

[Devices subject to this condition: **D2199, D2208, D2216, D3054]**

H23.27 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
CO	District Rule	218

[RULE 218, 8-7-1981; RULE 218, 5-14-1999]

[Devices subject to this condition: **D2198, D2207, D3053, D4354**]

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

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, Subpart	J
NOx	40CFR60, Subpart	GG

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

[Devices subject to this condition**: D2198, D2207]**

H23.48 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
NOx	40CFR60, Subpart	KKKK
SO2	40CFR60, Subpart	KKKK

[40CFR 60 SubpartKKKK, 7-6-2006]

[Devices subject to this condition**: D4354, D4355]**

H23.49 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, Subpart	Ja

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

[Devices subject to this condition**: D4355]**

I296.1 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall prior to the first compliance year hold a minimum 43,644 lbs/yr of NOx RTCs and 7,791 lbs/yr of SOx RTCs. This condition shall apply to the first year of operation, commencing with the initial operation of the turbine/duct burner.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum 41,290 lbs/yr of NOx RTCs and 8,435 lbs/yr of SOx RTCs for operation of the turbine/duct burner. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first year.

For the purpose of this condition, unused RTCs is the difference between (1) the amount of NOx RTCs required to be held at the beginning of a compliance year as specified in this condition and the amount of NOx emissions during each applicable compliance year and (2) the amount of SOx RTCs required to held at the beginning of a compliance year as specified in this condition and amount of SOx emissions during each applicable compliance year

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

[Devices subject to this condition: **D4354, D4355**]

K40.5 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/MMSCF. 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), heating content of the fuel, the flue gas temperature, and the generator power output (MW) under which the test was conducted.

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

[Devices subject to this condition: **D2198, D2207, C2210, C2213, D2216, C2217, D3053, C3058, D4354, C4361**]

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

Daily NOx emissions at the stack in PPMV at 15 percent oxygen on a dry basis and in pounds per day

Daily fuel gas usage

Daily ammonia usage

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 2012, 5-6-2005**]

[Devices subject to this condition: **D2198, D2199, D2207, D2208, D3053**]

K67.74 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Fuel use during the commissioning period

Fuel use after the commissioning period and prior to CEMS certification

Fuel use after CEMS certification

[**RULE 1303(a)(1)-BACT, 5-10-1996; Rule 1303(b)(2)-Offset, 5-10-1996; RULE 2012, 5-6-2005**]

[Devices subject to this condition: **D4354, D4355**]

FEE ANALYSIS

As shown in the following table, Chevron has paid all applicable fees for all of the subject applications.

Summary of Fee Analysis

A/N	Equipment Description	BCAT/ CCAT	Fee Schedule	Fee Type	Fiscal Year (1)	Fee
470782	Cogeneration Train D	033081 (BCAT)	D	New Construction	06-07	$ 3,701.25
470783	APCS for Cogen Train D	81 (CCAT)	C	New Construction	06-07	$ 2,681.75
474709	Cogeneration Train A	033081 (BCAT)	D (2)	Change of Condition	06-07	$ 1,367.36
512926	APCS for Cogen Train A	81 (CCAT)	C (3)	Modification	10-11	$ 6,626.10
474711	Cogeneration Train B	033081 (BCAT)	D	Change of Condition	06-07	$ 2.734.71
512927	APCS for Cogen Train B	81 (CCAT)	C (3)	Modification	10-11	$ 6,626.10
410837	Cogeneration Train C	033081 (BCAT)	D (2)	Change of Condition	02-03	$ 1,004.89
405276	APCS for Cogen Train C	81 (CCAT)	C	Change of Condition	02-03	$ 1,175.13
474712	Auxiliary Boiler	011605 (BCAT)	E	Change of Condition	06-07	$ 4,015.22
507253	RECLAIM/Title V Permit	555009 (BCAT)	na.	RECLAIM/Title V Permit Revision	09-10	$ 1,687.63
na.	Cogeneration Train D	na.	na.	Review of Air Quality Modeling & Health Risk Assessment	07-08	$ 4,311.27
na.	Cogeneration Train D	na.	na.	Public Notice for R212(c) & Title V Significant Revision	07-08	$ 1,577.58
				Total		**$34,774.28**
				Fees Paid		**$28,885.43**
				Outstanding Balance		**$ 5,888.85**

(1) Based on the date that the application was submitted.
(2) Qualifies for identical equipment discount.
(3) Includes 50% additional fee for modification without obtaining a permit to construct and 50% additional fee for expedited permit processing.

PERMIT HISTORY

There are no previous permits or permit applications for the Cogen Train D and associated APCS since they are proposed for new construction. The permit histories for the Cogen Trains A, B & C, Auxiliary Boiler and associated APCSs are contained in this section.

Permit History for Cogeneration A Train (A/N 474709)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
127406	7/28/86	na.	na.	Original Construction
166606	6/1/89	na.	na.	Change of condition to allow the following during start-up and shutdown of the Cogen unit: exceedance of the CO and NOx concentration limits for up 4 hours; operate without steam injection in the turbine or up to 6 hours; and operate without ammonia injection in the SCR for up to 6 hours.
219804	4/12/91			Modification of equipment in the existing natural gas supply system to allow use of Inglewood natural gas.
278185	8/11/95	na.	na.	Changed the fired duty rating from 563.4 MMBtu/hr (LHV) to 616 MMBtu/hr (HHV) to match their Rule 1109 plan. This rating includes the turbine and the duct burner. The duct burner rating was left at 119.7 MMBtu/hr (LHV). All mass emission limits for the Cogen remain the same.
388737	3/12/02.	na.	na.	As part of CARB3 RFG Project, pentanes were removed from some blend streams to control vapor pressure. The existing LPG vaporizer was modified to accept some of the excess pentanes. The Cogens were permitted to burn these excess pentanes.
357703	na.	na.	na.	Outstanding change of condition to be consolidated under AN 474709.
403042	4/17/02	na.	na.	Added equipment to increase steam injection to increase the power output from 40 MW to 46 MW.
405270	na.	na.	na.	Outstanding change of condition to be consolidated under AN 474709.
410838	na.	na.	na.	Outstanding change of condition to be consolidated under AN 474709.
474709	na.	na.	na.	Change of Condition to include this cogen in a New Source Review PM10 bubble with the proposed Cogen D Train. Also consolidating outstanding requests for ANs 357703, 405270 & 410838.

Permit History for Cogeneration B Train (A/N 474711)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
127407	8/25/86	na.	na.	Original Construction
166605	6/1/89	na.	na.	Change of condition to allow the following during start-up and shutdown of the Cogen unit: exceedance of the CO and NOx concentration limits for up 4 hours; operate without steam injection in the turbine or up to 6 hours; and operate without ammonia injection in the SCR for up to 6 hours.
219805	4/12/91	na.	na.	Modification of equipment in the existing natural gas supply system to allow use of Inglewood natural gas.
278187	8/11/95	na.	na.	Changed the fired duty rating from 563.4 MMBtu/hr (LHV) to 616 MMBtu/hr (HHV) to match their Rule 1109 plan. This rating includes the turbine and the duct burner. The duct burner rating was left at 119.7 MMBtu/hr (LHV). All mass emission limits for the Cogen remain the same.
357705	na.	na.	na.	Outstanding change of condition to be consolidated under AN 474711.
388738	3/12/02.	na.	na.	As part of CARB3 RFG Project, pentanes were removed from some blend streams to control vapor pressure. The existing LPG vaporizer was modified to accept some of the excess pentanes. The Cogens were permitted to burn these excess pentanes.
403043	4/17/03	na.	na.	Added equipment to increase steam injection to increase the power output from 40 MW to 46 MW.
405271	na.	na.	na.	Outstanding change of condition to be consolidated under AN 474711.
410839	na.	na.	na.	Outstanding change of condition to be consolidated under AN 474711.
474711	na.	na.	na.	Change of Condition to include this cogen in a New Source Review PM10 bubble with the proposed Cogen D Train. Also consolidating outstanding requests for ANs 357705, 405271 & 410839.

Permit History for Cogen Train A Air Pollution Control System (AN 512926)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
131328	8/25/86	na.	na.	Original Construction
166604	6/1/89	na.	na.	Change of condition to allow the following during start-up and shutdown of the Cogen unit: exceedance of the CO and NOx concentration limits for up 4 hours; operate without steam injection in the turbine or up to 6 hours; and operate without ammonia injection in the SCR for up to 6 hours.

Permit to Construct		**Permit to Operate**		**Description of Modification**
No.	Issue Date	No.	Issue Date	
R-259192	1/27/92	na.	na.	Replaced the electrically heated aqueous ammonia vaporizer with a steam heated anhydrous ammonia vaporizer (V-3975) that serves the Cogen A and B Trains and the Auxiliary Boiler.
283737	12/15/93	na.	na.	Replaced the common steam heated anhydrous vaporizer (V-3975) with individual aqueous ammonia vaporizers (V-3350) for each Cogen unit and the Aux. Boiler. Part of a refinery-wide project to replace anhydrous ammonia with aqueous ammonia.
321808	11/7/96	na.	na.	Replaced the existing aqueous ammonia vaporizer, which never functioned as expected, with a new aqueous ammonia vaporizer. The Chevron equipment number remained the same.
357704	na.	na.	na.	Outstanding change of condition to be consolidated under AN 512926.
405273	na.	na.	na.	Outstanding change of condition to be consolidated under AN 512926.
512926	na.	na.	na.	Chevron replaced the SCR catalyst with a different catalyst type without obtaining a permit to construct.

Permit History for Cogen Train B Air Pollution Control System (A/N 512927)

Permit to Construct		**Permit to Operate**		**Description of Modification**
No.	Issue Date	No.	Issue Date	
131329	8/25/86	na.	na.	Original Construction
166603	6/1/89	na.	na.	Change of condition to allow the following during start-up and shutdown of the Cogen unit: exceedance of the CO and NOx concentration limits for up 4 hours; operate without steam injection in the turbine or up to 6 hours; and operate without ammonia injection in the SCR for up to 6 hours.
259193	1/27/92	na.	na.	Replaced the electrically heated aqueous ammonia vaporizer with a steam heated anhydrous ammonia vaporizer (V-3975) that serves the Cogen A and B Trains and the Auxiliary Boiler.
283739	12/15/93	na.	na.	Replaced the common steam heated anhydrous vaporizer (V-3975) with individual aqueous ammonia vaporizers (V-3450) for each Cogen unit and the Aux. Boiler. Part of a refinery-wide project to replace anhydrous ammonia with aqueous ammonia.
321809	11/7/96	na.	na.	Replaced the existing aqueous ammonia vaporizer, which never functioned as expected, with a new aqueous ammonia vaporizer. The Chevron equipment no. remained the same.
357706	na.	na.	na.	Outstanding change of condition to be consolidated under 512927.
405275	na.	na.	na.	Outstanding change of condition to be consolidated under 512927.

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
512927	na.	na.	na.	Chevron replaced the SCR catalyst with a different catalyst type without obtaining a permit to construct.

Permit History for Cogeneration C Train (A/N 410837)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
296430	5/22/95	na.	na.	Original Construction
357708	na.	na.	na.	Outstanding change of condition to be consolidated under AN 410837.
401530	na.	F53464	7/17/02	Admin: To reinstate a fuel gas K.O. pot (D3056) that was inadvertently dropped from the permit.
403044	7/05	na.	na.	Added equipment to increase steam injection to increase the power output from 40 MW to 46 MW.
405272	na.	na.	na.	Outstanding change of condition to be consolidated under 410837.
410837	na.	na.	na.	Change of Condition being evaluated here.

Permit History for Cogen Train C Air Pollution Control System (A/N 405276)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
296431	5/22/95	na.	na.	Original Construction.
357715	na.	na.	na.	Outstanding change of condition to be consolidated under 405276.
405276	na.	na.	na.	Change of Condition being evaluated here.

Permit History for Auxiliary Boiler (A/N 474712)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
131331	8/20/86	na.	na.	Original construction.
213993	11/21/89	na.	na.	Increased the PM limit from 28 lb/day to 230 lb/day based on source test results. The increased PM emissions were offset through elimination of fuel oil burning in four process heaters and two boilers.
278188	8/11/95	na.	na.	Increased the permitted heat input from 286 MMBtu/hr to 342 MMBtu/hr based on approved Rule 1109 rating. NSR is not triggered for CO, PM10, and ROG since the permitted emission limits remained at 690, 230 and 95 lb/day, respectively. NOx and SOx are covered under RECLAIM.

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
474712	na.	na.	na.	Change of Condition to include this boiler in a New Source Review PM10 bubble with the proposed Cogen D Train.

Permit History for Auxiliary Boiler SCR

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
131330	8/20/86	na.	na.	Original construction.
213992	11/21/89	na.	na.	Increased the PM limit for the Aux. Boiler from 28 lb/day to 230 lb/day based on source test results.
283738	2/25/94	na.	na.	Replaced a common steam heated anhydrous vaporizer (V-3975), which served the Aux. Boiler and Cogen Trains A and B, with individual aqueous ammonia vaporizers (V-3550) for each Cogen unit and the Aux. Boiler. Part of a refinery-wide project to replace anhydrous ammonia with aqueous ammonia.
321806	11/7/86.	na.	na.	Replaced the existing aqueous ammonia vaporizer, which never functioned as expected, with a new aqueous ammonia vaporizer. The Chevron equipment number remained the same.

COMPLIANCE RECORD REVIEW

Appendix A contains a list of the notices to comply (NCs) and notices of violations (NOVs) issued to Chevron since January 1, 2008. There were no NCs or NOvs issued for the existing cogeneration units over this time period. There was one NC and one NOV issued for the Auxiliary Boiler. The NC and NOV were related to an exceedance of the 20 ppmv NH3 limit on the SCR. Chevron has subsequently replaced the SCR catalyst and performed another NH3 test. NH3 emissions were measured below 5 ppmv in the subsequent source test.

PROCESS DESCRIPTION:

GENERAL

A combustion gas turbine (CGT) is an internal combustion engine that operates with rotary motion. In electrical power generation applications, the high-pressure, high-temperature gas produced in the combustion chamber is expanded through the turbine blades to produce shaft power that is utilized to drive an electric generator and the combustion air compressor. Hot exhaust gas from the turbine flows through an insulated duct to an exhaust gas heat exchanger called a heat recovery steam generator (HRSG). The HRSG for each of the existing cogens is equipped with duct burners to provide additional heat for steam production. The proposed Cogen Train D will also have duct burners in the HRSG. For the Cogen Trains A and B, all of the steam produced in the HRSG is utilized in the refinery. For the Cogen Train C and proposed Cogen Train D, most of the steam is or will be utilized in a back-pressure steam turbine/generator to produce electrical power. Excess steam is utilized in the refinery.

COGENERATION TRAINS A, B and C

Each of the existing CGTs are General Electric (GE) Frame 6 gas driven turbines. There are only minor differences between the three gas turbines even though the No. 3 Turbine (Cogen C Train) was installed eight (8) years after the No. 1 and 2 Turbines (A and B Trains). The No. 1 and 2 Turbines are fired on natural gas and/or LPG (butane, propane, and/or pentane) and the No. 3 Turbine is fired on natural gas only. The No. 1 and 2 Turbines are GE Model No. PG-6531B and the No. 3 Turbine is a GE Model No. PG-6541B, which is a later model of the same turbine. For the existing CGTs, natural gas and steam are injected into the compressed air stream prior to injection into the combustor. Steam is injected into the stream to control combustion temperature for control of NOx emissions.

Each of the CGTs had original maximum gross ratings of 40 MW. The power generation capacity of each of the turbines has been increased from the original 40 MW to 46 MW through the use of the “Cheng Cycle”, which involves the injection of superheated steam into the gas turbine to drive it harder and increase the production of electricity. There was no increase in estimated maximum emissions for the Cogen Units with this conversion to the Cheng cycle since there was no increase in maximum fuel usage by the turbines.

The duct burners in the inlet to the HRSG for each of the cogens are low-NOx type burners, which are fired on natural gas and/or refinery fuel gas. At full duct burner firing, the Cogen A and B HRSGs each produce 264,000 lb/hr of 850 psig steam at 720°F. At maximum duct burner firing, the Cogen C HRSG produces 245,000 lb/hr of 850 psig superheated steam and 17,000 lb/hr of 150 psig saturated steam. For the Cogen C train, the 850 psig steam is routed to the steam turbine generator, which has a nominal output of 9 MW. Low pressure steam is exhausted from the steam turbine to the 150 psig steam header.

Refinery fuel gas is supplied to the Cogen A and B Train duct burners from the V-4540 fuel mix drum and to the Cogen C Train duct burner from the V-1000 fuel drum. The primary reason that refinery fuel gas is supplied from the V-1000 to the Cogen C duct burner is that the permit for this duct burner is conditioned with a 100 ppmv TRS limit for the fuel gas to the burner. At the time the Cogen C Train was constructed, fuel gas from the V-4540 fuel drum could not continually comply with the 100 ppmv TRS limit. Chevron has subsequently upgraded the refinery fuel gas treating systems. Currently, refinery fuel gas provided from any of the refinery fuel mix drums is continually below 100 ppmv.

The air pollution control systems (APCSs) for the existing cogeneration units include a CO catalyst for control of CO and VOC emissions and an SCR catalyst for control of NOx emissions. The CO and SCR catalysts are integrated into the HRSG. Current formulations of SCR catalyst are typically comprised of Vanadium Pentoxide (V_2O_5) as the active material deposited on or incorporated with a high surface area ceramic substrate, which is totally or primarily composed of activated titanium dioxide. In addition to Vanadium Pentoxide, the Chevron catalysts contain Tungsten Oxide as a promoter. SCR catalysts are commercially available in two basic geometric shapes, honeycomb and plate, or a hybrid of these. The catalyst for the existing cogen units are the ceramic honeycomb type. The catalyst for the Cogen Trains A and B were changed from a plate type to a honeycomb type in 2006 and 2007, respectively. The catalyst is described in the current permit as a plate type because

Chevron changed the catalyst without obtaining a permit to construct. The new honeycomb catalyst is able to achieve comparable control to the older plate catalyst with a smaller catalyst volume because it has higher activity per unit volume. The new catalyst for the Cogen A and B Trains is that same as the currently permitted catalyst for the Cogen C Train.

Stack gas NOx concentrations for the Cogen Trains A, B, and C each averaged 3.5 ppmv (@ 15% O2) during the months of June and July, 2010. The maximum hourly average NOx concentrations during June and July were 4.5, 5.3 and 31 ppmv (@ 15% O2), respectively. The 31 ppmv hourly average NOx concentration for the Cogen Train C occurred during an emergency shutdown of the unit. The next highest hourly average NOx concentration for Train C during the two-month period was 4.5 ppmv. The hourly average NOx concentrations for normal operation of each of the cogen trains during this two-month period were below the permit limit of 9 ppmv (@ 15% O2).

Cogen A, B and C Train ammonia source test results for the last two years are summarized in the table below. As seen in the Table, measured ammonia concentrations were well below the 20 ppmv ammonia limit for each of the cogen units.

Ammonia Source Test Results for Cogen Trains A, B and C

Source Test Date	**Ammonia Concentration (ppmv @ 15% O2)**		
	Cogen Train A	**Cogen Train B**	**Cogen Train C**
3rd Quarter 2008	0.2	6.5	1.8
4th Quarter 2008	0.1	1.4	None Required
1st Quarter 2009	3.8	3.5	
2nd Quarter 2009	6.6	0.7	
3rd Quarter 2009	0.5	0.6	3.0
4th Quarter 2009	0.4	3.1	None Required
1st Quarter 2010	1.0	0.3	
2nd Quarter 2010	1.0	0.2	

The table below contains specifications for the new Cogen A and B Train SCR catalysts.

Specifications for Cogen Train A and B Selective Catalyst Reduction (SCR)

Catalyst Properties	**Specifications**
Manufacturer	Cormetech
Catalyst Description	Ti-V-W
Catalyst Dimensions (per block)	4 ft 5 in (h) x 4 ft 8 in (w) x 6 ft 11 in (d)
Number of Blocks	21
Configuration	Homogeneous Honeycomb
Catalyst Volume	667 ft^3
Space Velocity	21,700 hr^{-1}
Catalyst Life (guarantee)	36 months
Optimum Operating Temperature	597 - 678°F

Catalyst Properties	Specifications
Ammonia Injection Rate	75 lb/hr aqueous ammonia (30 wt %)
NOx Removal efficiency	87 percent
NOx Concentration @ Stack Outlet (guarantee)	5.5 ppmvd, 1-hr average, 15% O2
NH3 Concentration @ Stack Outlet (guarantee)	10 ppmvd, 1-hr average, 15% O2

Average stack gas CO concentrations for each of the Cogens were less than 3 ppmv (@ 15% O2) for the months of June and July. The maximum hourly-average CO concentrations during this two-month period were 7.2, 2.0, and 5.7 ppmv (@ 15% O2), respectively, for the Cogen Trains A, B and C. The permit limit for CO for each of the cogens is 10 ppmv (@ 15% O2).

COGENERATION TRAIN D

The proposed Cogeneration Train D will utilize a GE model PG6581B CGT, which is also a frame 6 turbine. It will also include a duct burner equipped HRSG and a back-pressure steam turbine/generator. The combustor is a dry low-NOx (DLN) type in which air and natural gas are pre-mixed but steam is not injected. Pre-mixing inhibits NOx formation by minimizing the flame temperature and the concentration of oxygen at the flame front.

The CGT will be fired on natural gas and the duct burner on refinery fuel gas or natural gas. The RFG will be supplied from the V-4540 fuel mix drum. The CGT and steam turbine generators are rated at 42.8 and 4.0 MW gross power (at 65°F), respectively. The CGT will be fired on natural gas and the duct burner, which has a capacity of 120 MMBtu/hr, will be fired on refinery fuel gas and/or natural gas. The technical specifications for the CGT and HRSG are shown in the following table.

Combustion Gas Turbine and HRSG Specifications

Parameter	Specifications
Manufacturer	Gas Turbine: General Electric
Model	Gas Turbine: Frame 6B (PG6581B)
Turbine NOx Combustion Control (type)	Dry Low NOx (DLN)
Natural Gas Heating Value (HHV)	22,939 Btu/lb 1,029 Btu/SCF 1,050 Btu/SCF (SCAQMD default) used for emission calculations
Natural Gas Heating Value (LHV)	20,672 Btu/lb 927 Btu/SCF
Gas Turbine Heat Input (HHV)	493 MMBtu/hr at ISO 486 MMBtu/hr at annual avg. temp. 508.7 MMBtu/hr at 40^{o} F.
Net Gas Turbine Heat Rate, LHV	10,633 BTU/kW-hr at ISO 10,674 BTU/kW-hr at annual avg. temp.

Parameter	Specifications
Net Gas Turbine Heat Rate, HHV	11,799 BTU/kW-hr at ISO 11,845 BTU/kW-hr at annual avg. temp.
Duct Burner Heat Input (HHV)	115.1 MMBtu/hr at ISO base loaded 115.4 MMBtu/hr at annual avg. temp. at base 132.0 MMBtu/hr (max)
Steam Turbine Power Generation	4.0 MW at 36°F 4.0 MW at ISO 4.0 MW at annual avg. temp.
Gas Turbine Power Generation	43.8 MW at 36°F 42.2 MW at ISO 41.4 MW at annual avg. temp.
Total Gross Power Generation[1]	47.8 MW at 36°F 46.2 MW at ISO 45.4 MW at annual avg. temp.
Total Net Power Generation	44.5 MW at ISO 43.8 MW at annual avg. temp.
Net Plant Heat Rate, (HHV)	13,660 BTU/kW-hr at ISO 13,741 at annual avg. temp.
Net Plant Heat Rate, (LHV)	12,331 BTU/kW-hr at ISO 12,404 BTU/kW-hr at annual avg. temp.
Net Plant Efficiency, (LHV)	27.7% electrical efficiency at ISO 27.5% electrical efficiency at annual avg. temp 87.2% cogen efficiency at ISO 87.6% cogen efficiency at annual avg. temp.

(1) Normal operation at 100% load with duct burners on

A CO catalyst and SCR catalyst will be integrated into the HRSG. The CO oxidization catalyst will be used to control CO and VOC emissions down to 2 ppmv (15% O2) each. The oxidation catalyst will also provide some control of BTEX, formaldehyde and acetaldehyde emissions. The SCR, which is located downstream of the CO catalyst, will provide control of NOx emissions down to 2 ppmv (15% O2). Specifications for the proposed CO and SCR catalyst are shown in the following tables. Vendor's guarantees and performance curves for the catalysts are contained in the engineering file.

Specifications for CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	BASF or equivalent
Catalyst Description	Metal monolith or equivalent
Catalyst Dimensions	56 ft (h) x 11 ft (w) x 2.6 in (d)
Catalyst Volume	100 ft^3
Catalyst Life (performance guarantee)	Earliest of 3 ½ years from delivery or 3 years/25,000 hours from first gas-in
Space Velocity	200,000 hr^{-1}
Optimum Operating Temperature	851 to 1149°F

Catalyst Properties	Specifications
CO Removal efficiency	92 percent
CO Concentration @ Stack Outlet	2 ppmvd, 1-hr average, 15% O2
VOC Removal Efficiency	50 percent
VOC Concentration @ Stack Outlet	2 ppmvd, 1-hr average, 15% O2
SO2 to SO3 Conversion	2-4 percent
NO to NO2 Conversion	0 percent

Specifications for Selective Catalyst Reduction (SCR)

Catalyst Properties	Specifications
Manufacturer	Cormetech or equivalent
Catalyst Description	Ti-V-W
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 Volume	300 ft^3
Space Velocity	50,000 hr^{-1}
Catalyst Life (performance guarantee)	Earliest of 39 months from delivery or 26,280 hours from first gas in
Optimum Operating Temperature	597 - 678°F
Ammonia Injection Rate	90 lb/hr aqueous ammonia (30% by weight)
NOx Removal efficiency	87 percent
NOx Concentration @ Stack Outlet	2 ppmvd, 1-hr average, 15% O2
NH3 Concentration @ Stack Outlet	5 ppmvd, 1-hr average, 15% O2

The SCR catalyst will use ammonia injection in the presence of the catalyst to reduce NOx. Diluted ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst module. Aqueous ammonia will be stored in existing storage tank V-686 (D1859 in P21S5), which is located near the main ammonia loading/unloading rack. Ammonia is pumped by existing pump P-14 (or spare pump P-14A) to the cogen units. For the Cogen D Train, the ammonia will be metered into Ammonia Vaporizer V-3710 (or spare vessel V-3720). In the vaporizer, ammonia is atomized through a fine nozzle with plant air. The resulting small droplets of ammonia evaporate into a stream of hot ambient air, which is supplied by Dilution Air Blower K-3710 (or spare blower K-3720) and heated in Air Heater E-3710 (or spare heater E-3720). The ammonia-air mixture is evenly distributed across an ammonia injection grid inside the heat recovery steam generator, which is located upstream of the SCR.

EQUIPMENT LIST

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

New Equipment

Equipment	Device Tag No.	Device ID	Dimensions / Rating
Gas Turbine	TPG-3700	D4354	508.7 MMBTU/HR
Generator, Electric	PG-3700	D4354	43.75 MW
Duct Burner	DB No.4	D4355	132.0 MMBTU/HR
Steam Turbine	TPG-3750	D4357	
Generator, Electric	PG-3750	D4357	4.0 MW
Selective Catalytic Reduction (SCR)	R-3700	C4361	
Carbon Monoxide (CO) Oxidation	R-3750	C4360	
Stack		na.	10.5' DIA x 87.5' HT.
Oil Cooler , Natural Gas Compressor	E-3120	na.	3.75MMBtu/hr
Heat Recovery Steam Generator, Tube Type	E-3700	D4358	
Dilution Air Heaters (Ammonia vaporization system)	E-3710/E-3720	na.	105 KW Each One spare
Closed Cooling Air Cooler	E-3760	na.	14.6 MMBtu/hr; 8 fans, 30 HP Each
Compressor, Fuel Booster, Natural Gas	K-3120	D4356	9075 scfm; 600 HP
Oil Filters, Natural Gas Compressor (One Spare)	K-3130/K-3135	na.	Ht: 2 ft. 6 in; Dia: 1 ft.
Dilution Air Fans (One Spare)	K-3710/K-3720	na.	340 scfm, 10 HP each
Deaerating Steam Desuperheater	K-3730	na.	Capacity: 28k lb/hr
HRSG HP Steam Desuperheater	K-3750	na.	Capacity: 270k lb/hr
STG Bypass Desuperheater	K-3770	na.	Capacity: 130k lb/hr
STG Exhaust Desuperheater	K-3790	na.	Capacity: 130k lb/hr
Oil Pump (One Spare)	P-3120/P-3130	na.	45 GPM; 15 HP
BFW Pump (One Spare)	P-3250/P-3260	na.	700 GPM; 600 HP
Closed Cooling Pump (One Spare)	P-3780/P-3790	na.	2800 GPM; 150 HP
Suction Knockout Drum, Natural Gas Compressor	V-3120	na.	Ht: 6 ft; Dia:3 ft.
Coalescing Oil Separator, Natural Gas Compressor	V-3130	na.	Ht: 9 ft. 2 in; Dia: 3 ft.
Oil Reservoir, Natural Gas Compressor	V-3135	na.	Ht: 10 ft.; Dia: 3 ft.
Dearator	V-3290	na.	
HP Steam Drum	V-3700	na.	Lgth: 20 ft.; Dia. 7 ft.
Ammonia Vaporizers (One Spare)	V-3710/V-3720	D4362	Lgth: 8.7 ft.; Dia: 3 ft
IP Steam Drum	V-3750	na.	Lgth: 13 ft; Dia. 4.6 ft
Closed Cooling Tank	V-3760	na.	Ht: 8 ft.; Dia: 2 ft.
HP Continuous Blowdown Drum	V-3770	na.	Ht: 9.5 ft.; Dia: 3.5 ft.
IP Continuous Blowdown Drum	V-3780	na.	Ht: 10 ft.; Dia. 3.5 ft.

OPERATING SCENARIOS

The four possible modes of operation for the Cogen Train D are normal, commissioning, startup, and shutdown. As documented in the *Calculation* section of this evaluation, the criteria pollutants emissions for each of these modes are potentially different and hence are evaluated independently.

***Normal Operation* -** Normal operation occurs when the cogeneration train and APCS are working optimally. Emissions may vary slightly during normal operation due to variations in ambient conditions and the age and condition of the APCS.

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 (usually the first year of operation) may be higher than those during a non-commissioning year due to the fact that the combustors may not be optimally tuned and the SCR/CO catalysts may be only partially operational or not operational at all. Commissioning is expected to occur over a one month period. A summary of commissioning activities is contained in the following table.

Summary of Commissioning Activities

Day	Description of Commissioning Activity
1	First fire-bring machine to full speed no load (FSNL) and then operate for one hour to check overspeed trip. Shut the machine down.
2	Bring machine to FSNL and then operate at FSNL for six hours to do synchronization checks and synchronize to spinning reserve operation. Then shut the machine down.
3	Bring machine to FSNL, synchronize with Edison, go to base load operation and operate for ten hours to do combustion tuning. Then shut the machine down.
4	Same as Day 3.
5	Bring machine to FSNL, synchronize with Edison, go to base load operation, fire duct burners and operate for ten hours to test duct burners. Then shut the machine down.
6	Same as Day 5.
7	Same as Day 5.
8	Load catalyst
9	Load catalyst
10	Load catalyst
11	Load catalyst
12	Bring machine to FSNL, synchronize with Edison, go to base load operation, fire duct burners and operate for 10 hours to balance ammonia injection, test ammonia slip. Leave machine in operation for CEMS Drift Testing.

Day	Description of Commissioning Activity
13	Continue with balancing ammonia injection, testing ammonia slip, CEMS Drift Testing.
14	Same as Day 13.
15	Same as Day 13.

Start-Up and Shutdown – The proposed cogeneration unit will be subject to a number of planned shutdowns as well as emergency unplanned shutdowns (SD), which will be followed by start-ups (SUs). SU/SDs include:

- "Crank Soak" (rotor cleaning procedure) and other maintenance items at a frequency of four times a year for one to two days.
- Hot Gas Path" inspection every three years for a period of about 10 days.
- Major maintenance turnaround every six years for a period of approximately 21 days.

SUs following planned SDs will normally be cold SUs since the turbine is shutdown for an extended period of time prior to SU. Occasionally a hot SU will be performed following an emergency SD. NOx emissions are high during SUs 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 SDs than during normal operation because injection of ammonia into SCR ceases during part of the shutdown sequence.

Shutdown, cold start-up and hot start-up procedures are summarized below.

Shutdown Procedure (estimated 2 hour duration)

- Prior to commencing the gas turbine shutdown, the duct burner firing rate is reduced to zero.
- Over a period of about 75 minutes, the load on the generator is decreased to spinning reserve (2-4 megawatts).
- Before the SCR temperature drops below 597^o F., ammonia injection is stopped and the ammonia injection system is shut down.
- The load is taken completely off the generator and a fired shutdown is initiated.
- The fired shutdown sequence includes the following:
  - Fuel flow is slowly reduced.
  - Turbine speed is slowly decreased.
  - Fuel flow to the turbine is stopped at about 30% speed.

Cold Startup Procedure (estimated 2 hour duration)

- The ammonia injection system is commissioned.
- The combustion gas turbine is accelerated from rest to 2000 RPM using the electric starting motor.
- The combustors are purged with air for five minutes.
- The turbine ignition sequence takes place.
- Ignition is verified.
- The turbine is accelerated to 3000 RPM and the starting motor disengages.
- The turbine is accelerated to full speed with no load on the generator. Fuel consumption is about 135 MMBTUH.

- This operation is held for 30 minutes to allow metal temperatures to stabilize.
- Turbine speed is increased, the generator is synchronized with Edison and 2-4 mW load is placed on the generator.
- The load on the generator is increased in 5 mW increments until baseload operation is reached.
- Ammonia injection is commenced when the SCR temperature approaches 597^o F.

Hot Startup Procedure (estimated 1 1/2 hour duration) – The hot startup procedure is the same as the cold startup procedure except that the 30-minute hold for metal temperature stabilization is unnecessary. The duct burners are not fired during hot or cold startups.

CALCULATIONS

Criteria air pollutant (CO, NOx, PM_{10}, SO2, and VOC) emission estimates are contained in this section. These estimates include emissions for non-emergency operating conditions such as normal operation, commissioning, planned shutdowns and start-ups. Emissions from emergency events are not included since they cannot be accurately anticipated and estimated.

The CO, NOx and VOC emissions are expected to be greater during commissioning than during normal operation as air pollution control equipment may only be partially operational or not operational at all. The CO, NOx and VOC emissions will also be higher during start-ups due to the phased effectiveness of the SCR and CO catalysts that gradually come online as the operating temperatures are being reached. Emissions during shutdowns will be higher than normal operation but lower than start-up emissions.

COGENERATION TRAINS A, B & C AND AUXILIARY BOILER

Each of these existing units was subject to NSR upon original construction. None of the proposed changes of permit conditions will impact the maximum potential emissions of CO, NOx, PM10, ROG or SOx. The permits for each of these units have limits on mass emissions of CO, PM10 and ROG. The Cogen A and B trains also have annual NOx and SOx limits under Regulation XVII – PSD. Mass emission limits for CO, PM10, ROG, NOx and SO2 are shown for each of these units in the following table.

Existing Mass Emission Limits For CO, PM10 and ROG, NOx and SOx

Pollutant	Mass Emission Limit			
	Cogen A Train	Cogen B Train	Cogen C Train	Aux. Boiler
CO	160 lb/day	160 lb/day	160 lb/day	690 lb/day
PM10	174 lb/day	174 lb/day	174 lb/day	230 lb/day
ROG	86 lb/day	86 lb/day	86 lb/day	95 lb/day
NOx	46.42 ton/yr	48.44 ton/yr	na.	na.
SO2	10.75 ton/yr	10.87 ton/yr	na.	na.

Permit to construct A/N R-213993 for the Auxiliary Boiler was conditioned with NOx and SOx emission limits of 131 lb/day and 152 lb/day, respectively. The original permits to construct for the Cogen A, B and C Trains were conditioned with NOx and SO2 emission limits of 302 lb/day and 140 lb/day, respectively. These limits were all based on Regulation XIII offset requirements. These emission limits were subsequently subsumed by RECLAIM so they have been removed from the RECLAIM Facility Permit.

The permit condition changes being analyzed in this evaluation for the Cogen A, B and C Trains and the Auxiliary Boiler are not expected to impact the emission of any of the criteria air pollutants. As demonstrated in the Process Description section, NOx emissions for the Cogen A and B Train with the new catalysts are well below the permitted 9 ppmv NOx limit. Therefore, the original emission estimates, which are the basis of the emission limits discussed above, will be carried through to the current applications as summarized in the following table.

New Source Review: Maximum PTE for CO, PM10, and ROG, NOx and SOx

Pollutant	Maximum Potential Emissions (lb/day)			
	Cogen A Train	Cogen B Train	Cogen C Train	Aux. Boiler
CO	160	160	160	690
PM10	174	174	174	230
ROG	86	86	86	95
NOx	302	302	302	131
SO2	140	140	140	152

The PM10 mass emission limits for the Cogen A Train, Cogen B Train, and Auxiliary Boiler will be combined into a bubble PM10 limit with the proposed Cogen D Train. The new combined PM10 emission limit for the Cogen A Train, Cogen B Train, Cogen D Train and Aux. Boiler will be 577 lb/day, which is one (1) lb/day less than the sum of the current individual PM10 emission limits for the Cogen A Train, Cogen B Train and Aux. Boiler (174 + 174 + 230 -1). Based on the maximum potential PM10 emissions (30-day average) for the proposed Cogen Train D, a PM10 emission limit of 113 lb/day will be imposed on the Cogen Train D but the PM10 emissions will be entered as 0 lb/day in the NSR database since there is no increase in net maximum potential PM10 emissions under NSR.

COGENERATION TRAIN D

Requirements

Criteria pollutant emissions must be estimated to evaluate compliance with various rules or regulations including: Rule 212, Rule 1303, Regulation XVII and Rule 2005. 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.

Summary of Criteria Air Pollutant Emission Estimate Requirements

Rule Requirement	Estimate Required	Criteria Pollutant					
		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)(4)		√				
	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 1703(a)(2) – BACT	Annual (2)	√			√	√	
Rule 1703(a)(3) – Signif. Increase	Annual (1)	√			√	√	
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) For Appendix A screening

Methodology

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 cogen unit is completed in one month. The emissions for a normal operating month must include emission from shutdowns and start-ups. As discussed in the *Process Description* section, Chevron anticipates that the cogen be shutdown an average of 4 times per year for scheduled maintenance and inspection activities. The permit will be conditioned with a limit of 4 SU/SDs per month and 12 SU/SDs per year. Calendar monthly emissions during normal operation of the cogen are based on 27-days of full operation at the maximum combustion rate of 640.7 MMBtu/hr (HHV) and four days with 8 hours of full load operation, one shutdown, 12 hours of downtime and one start-up. Annual emission estimates are also evaluated for both a commissioning and non-commissioning year. The commissioning year includes one 31-day commissioning month. The remainder of the year will include 322 days of continuous operation at full load and 12 days that each include 8 hours of full load operation, a shutdown, 12-hour downtime period and a start-up. The non-commissioning year is comprised of 353 days of continuous operation at full load and 12 days that each includes 8 hours of full load operation, a shutdown, 12-hour downtime period and a start-up.

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

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

where,

ppmvd = Pollutant concentration limit at stack outlet at 15% O_2,dry basis
MW = Molecular weight, lb/lb-mol
MV = Molar volume at 60ºF = 379.5 dscf/lb-mol
F_d = Dry oxygen f-factor for natural gas = 8,710 dscf/MMBTU

The SO2 emissions during normal operation are based on the following formula and assumptions:

$$\text{Emissions} = \left[508.7\ \text{MMBtu/hr} \times \left(\frac{1}{\text{HHV}}\right) \times 5\ \text{ppmvd} \times \text{MW} \times \left(\frac{1}{\text{MV}}\right)\right] + \left[132\ \text{MMBtu/hr} \times \left(\frac{1}{\text{HHV}}\right) \times 30\ \text{ppmvd} \times \text{MW} \times \left(\frac{1}{\text{MV}}\right)\right] = 1.05\ \text{lb/hr}$$

where,

HHV = High heating value of fuel (conservatively assume HHV for natural and refinery fuel gas is 1050 Btu/scf)
MW = Molecular weight of SO2 (64 lb/lb-mol)
MV = Molar volume at 60ºF = 379.5 dscf/lb-mol

The PM10 emission estimates are based on the default PM emission factor of 7.5 lb/MMcf for the category "NG combustion; external, other" from the Instruction Book for the District's AER Program. This factor equates to 0.0071 lb/MMBtu based on an assumed high heating value (HHV) of 1050 Btu/scf. It is assumed that PM is equivalent to PM10 for a gaseous fuel fired combustion source. It is also assumed that PM10 emissions are the same during commissioning, startup and shutdown as during normal operation.

Maximum hourly emissions are shown in the following table.

Maximum Hourly Emissions

Type Operation	Emissions (lb/hr)				
	CO	PM10	VOC	NOx	SO2
Normal (1)	2.92	4.55	1.67	4.80	1.05
Commissioning (2)	68.2	4.55	5.28	38.4	0.52
Start-up (2)	33.6	3.44	4.27	25.8	0.39
Shutdown (2)	192.2	2.55	22.0	25.9	0.29

(1) Operation at full load of 640.7 MMBtu/hr (HHV). CO, NOx and VOC emission estimates based on 2 ppmvd (15% O2) stack limit. SO2 emission estimates based on 30 ppmv sulfur limit for refinery fuel gas and average natural gas sulfur content of 5 ppmv.
(2) Based on consultants/manufacturers estimates. Detailed estimates for SU, SD and commissioning are contained in Appendices B through D.

Commissioning, Shutdown and Start-up Emissions (Per Event)

Event	Emissions (lb)				
	CO	PM10	VOC	NOx	SO2
Commissioning (1)	4270	670	394	5862	74
One Cold Start-up (1)	44	4.5	5.7	32	0.5
One Shutdown (1)	231	3.5	27	29	0.4

(1) Based on manufacturers estimates. Detailed estimates for SU, SD and commissioning are contained in Appendices B through D.

Maximum Annual Emissions (1)

Type Operation	Emissions (lb/yr)				
	CO	PM10	VOC	NOx	SO2
Normal Year (2)	28319	39858	14701	42048	9198
Commissioning Year (3)	30416	37143	13852	44339	8491

(1) Based on 365-day year
(2) Emissions for the following scenario that yields the highest emissions: (1) 365 days of full load operation or (2) 353 days of continuous operation at full load with 12 days consisting of 8 hours of operation, a shutdown, 12 hours of downtime and a start-up.
(3) Emissions for the following scenario that yields the highest emissions: (1) 31 days of commissioning and 334 days of full load operation, or 31 days of commissioning and 322 days of full load operation with 12 days consisting of 8 hours of operation, a shutdown, 12 hours of downtime and a start-up.

Maximum Monthly Emissions (31-day Month)

Type Operation	Emissions (lb/month)				
	CO	**PM10**	**VOC**	**NOx**	**SO2**
Normal Month (1)	3086	3126	1266	3508	718
Commissioning Month (2)	4270	670	394	5862	74

(1) Emissions for the following scenario that yields the highest emissions: (1) 31 days of continuous operation at full load or (2) 27-days of continuous operation at full load with 4 days consisting of 8 hours of operation, a shutdown, 12 hours of downtime and a start-up.
(2) Assumes commissioning is completed in a 31-day month.

Daily (30-day Average) Emissions

Type Operation	Emissions (lb/day)				
	CO	**PM10**	**VOC**	**NOx**	**SO2**
Normal Month (1)	103	113	42.2	119	26
Commissioning Month (1)(2)	142	22	13.1	195	2.5

(1) 30-day average emissions = (maximum monthly emissions) / 30
(2) Assumes commissioning is completed in a 31-day month.

In addition to the combustion related emissions, the Cogen D Train permit unit will have VOC emissions from fugitive components. VOC emissions for these fugitive components are estimated by multiplying the total number of each fugitive component type by an appropriate emission factor. The emission factors that are utilized are standard emission factors for fugitive components at refineries that comply with the inspection and monitoring requirements of District Rule 1173. These factors were originally developed for estimation of fugitive component VOC emissions for the CARB Reformulated Fuels projects that were performed at the refineries in the South Coast Basin.

As seen in the detailed fugitive VOC emission calculations, which are contained in Appendix E**,** the fugitive VOC emissions for the Cogeneration D Train permit unit are estimated to be 3.9 lb/day. Total VOC emissions, including the 42.2 lb/day of combustion related VOC emissions, are estimated to be 46.1 lb/day.

EVALUATION OF REQUESTED CHANGES OF PERMIT CONDITIONS

This section contains a review and analysis of additional permit condition changes and modifications proposed by Chevron for the Cogen Trains A, B & C and associated APCSs.

<u>TURBINES AND DUCT BURNERS</u>

1. Specify a 60-minute averaging period for the 10 ppmv CO and 9 ppmv NOx limits. [Cogen A; Cogen B; Cogen C]

   The command and control (C&C) permits for the Cogeneration A and B Trains contained the following two conditions:

- This equipment shall not discharge in excess of 9 ppmv of Oxides of Nitrogen, 10 ppmv or Carbon Monoxide, and 20 ppmv of Ammonia except during the first six (6) hours of startup.
- All concentrations of gaseous emissions shall be expressed in parts per million by volume corrected to 15% O2 on a dry basis, and shall be measured over a fifteen minute average time period.

The 15-minute averaging period specification was dropped during the conversion of the C&C permits to the RECLAIM Facility Permit format in the mid 1990s. There was no specification of the averaging period in permits or permit evaluations for the Cogen C Train.

In an August 7, 2007 SCAQMD Policies and Procedures memo from Mr Mohsen Nazemi, it is specified that BACT emission limits for all new permits for combustion equipment shall be imposed on a one-hour averaging period. This is consistent with the shortest averaging period for Federal and State Ambient Air Quality Standards (AAQSs). It is also specified that conversion of a BACT limit to a one hour averaging period from a shorter averaging period would probably not trigger an NSR event if the hourly emission of the equipment is not increased.

In this case, changing from a 15-minute averaging period to a one-hour will not impact the estimated maximum potential emission under NSR. Therefore, for consistency with other emission limits, it is recommended that the 15-minute averaging period for the CO and NOx limits be changed to a 60-minute averaging period.

2. Condition D12.6: Delete this condition, which requires a CMS to indicate and record the steam-to-fuel ratio. [Cogen A; Cogen B; Cogen C]

   Steam or water is injected into the combustion chamber of the Cogen turbines for control of NOx. Steam injection and SCR with a resulting 9 ppmv NOx emission limit was BACT for NOx at the time that the existing cogeneration units were constructed. Since steam or water injection is an essential component of the NOx control system for the subject cogens, removal of this BACT monitoring condition is not warranted.

   Also, as discussed later in this evaluation, all of the subject turbines are subject to NSPS Subpart GG (Standards of Performance for Stationary Gas Turbines). Section 60.334(a) of this subpart requires that the operator of any subject turbine utilizing water to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. The system shall be accurate to within 5.0%. A calibration accuracy of 10% is currently specified in condition D12.6. It is recommended that the calibration accuracy specified in this condition be changed to 5% to be consistent with this NSPS.

3. Condition D12.6: If condition D12.6 cannot be removed from the permit, change the calibration requirement for the steam-to-fuel ratio CMS from monthly to annual. [Cogen A; Cogen B; Cogen C]

   According to Chevron, the Cogens must be shutdown to calibrate the steam-to-fuel ratio CMS since these monitors are utilized in the feedback control system for the Cogens.

The subject steam and flow measurement equipment utilize orifice type flow meters. The flow is determined by the differential pressure across the orifice. This widely used type of process monitor (pressure measurement) is very robust and is not as susceptible to drift as more complex emissions monitoring equipment. Annual calibration is standardly specified for this type of monitor. It is judged that annual calibration of these monitors in conjunction with a tighter calibration specification is adequate to assure the monitors are collecting data of sufficient accuracy and precision. Recommend that the calibration frequency be changed to annual.

4. Condition E73.2: Replace the word “turbine” with “SCR” and place the condition on the SCRs. [Cogen A; Cogen B; Cogen C].

   This condition reads:

   > “Notwithstanding the requirements of Section E conditions, the operator may, at his discretion, choose not to use or inject ammonia in the turbine if any of the following requirement(s) are met: During startup and shutdown of the cogeneration trains. **[RULE 1303(a)(1)-BACT, 5-10-1996]**”

   Agree that this condition applies to the SCRs and not the turbines. Recommend that the word “turbine” in the condition be replaced with “SCR” and that this condition be removed from each of the turbines and be tagged to each of the SCRs.

5. Specify a 3-hour averaging period for the 100 ppm fuel total sulfur limit of permit condition B61.2 [Cogen Train C duct burner only]

   The averaging time for the 100 ppmv total sulfur limit was not clearly specified or documented when the BACT determination was made for the Cogen Train C during original permitting of the unit in 1995 under AN 296340.

   The duct burner on the Cogeneration C Train unit receives refinery fuel gas from the V-4540 Fuel Gas Mix Drum (D1892). This mix drum is equipped with a fuel sulfur GC that utilizes a Flame Photometric Detector (FPD) to quantify total reduced sulfur emissions. This fuel sulfur GC is a semi-continuous monitor that operates on a 15 minute cycle. A sample aliquot is collected by the GC every 15 minutes. The 15 minute cycles are required for the sulfur compounds to elute from the capillary column and be quantified with the FPD.

   Due to the 15-minute sample cycle length, an averaging period of less than 15 minutes is not feasible. An averaging period of 15-minutes is not feasible since it does not provide the operator adequate time to respond to changes in the fuel sulfur concentration once the results from analysis of the sample aliquot are reported. A three or four hour limit is also not appropriate since at the time that this BACT limit was imposed Rule 431.1 included a limit of 40 ppmv with a 4-hour averaging period.

   Based on this analysis, an averaging period of 1-hour is judged to be appropriate since it provides the refinery time to respond to SO2 excursions due to plant upsets, etc. and is not considered to be less stringent than the Rule 431.1 limit of 40 ppmv with a 4-hour averaging period.

6. Tag existing source test condition D28.11, which is tagged to the Cogen A and B turbines to the Cogen C turbine. [Cogen C]

   Condition D28.11, which specifies a PM10 and VOC source test every three years as Title V periodic Monitoring, was moved from the Cogen Train C SCR to the turbine during preparation of the Title V permit.

AIR POLLUTION CONTROL SYSTEMS

1. Specify a 60-minute averaging period for the 20 ppmv NH3 emission limit [Cogen A; Cogen B; Cogen C]

   As discussed above, the C&C permits for the Cogen A and B Trains included the following conditions:

   - This equipment shall not discharge in excess of 9 ppmv of Oxides of Nitrogen, 10 ppmv or Carbon Monoxide, and 20 ppmv of Ammonia except during the first six (6) hours of startup.
   - All concentrations of gaseous emissions shall be expressed in parts per million by volume corrected to 15% O2 on a dry basis, and shall be measured over a fifteen minute average time period.

   Based on the discussion above regarding the averaging period for the CO and NOx concentration limits, it is recommended that a 60-monute averaging period be imposed on the subject NH3 concentration limit.

2. Delete Condition No. D12.2, which requires a continuous monitoring system (CMS) and recorder for the ammonia-to-emitted NOx ratio. [Cogen A; Cogen B; Cogen C]

   There is not a limit on the ammonia injection rate but there is a limit on the ammonia concentration. Since the cogen unit stacks are not equipped with ammonia CEMS, the ammonia injection rate and the ammonia injection rate relative to the emitted NOx concentration provide a useful continuous indicator of SCR performance and ammonia slip. The ammonia injection rate is routinely required on all SCRs at major sources. Deletion of the condition is not warranted. As seen in the *Permit Conditions* section of this evaluation, some clarification of this condition is recommended.

3. Revise Condition D28.1 from quarterly NH3 source testing to annual source testing. [Cogen A; Cogen B]

   Permits for cogeneration units are routinely conditioned with a source test conditions that requires the operator to perform quarterly ammonia source tests during the first year of operation and annually thereafter. More frequent monitoring is warranted during the first year of operation to confirm that the unit is functioning as designed during initial startup and shakedown of the unit. The permit for the Cogen Train C, which was permitted 10 years after the Cogen Trains A and B, is conditioned with an annual ammonia source test.

   The ammonia source test results for the last 5 and 10 year periods are summarized in the table below.

Summary of Cogen Train A and B Ammonia Source Test Results

	Measured Ammonia Concentration (ppmv, @ 15% O2)	
	Cogen Train A	**Cogen Train B**
5 Year Period – Average Value	2.9	2.7
5 Year Period – Maximum Value	7.9	6.4
10 Year Period – Average Value	3.9	2.8
10 Year Period – Maximum Value	12.5	7.7

As seen in the tale, the average and maximum ammonia concentration measured during the quarterly source tests over the last five and ten year periods for each of the subject cogeneration units is well below the 20 ppmv ammonia concentration limits for each unit. Based on the large margin of compliance with the ammonia concentration limit for each of the cogeneration units over the last decade, it is judged that an annual ammonia source test frequency is adequate to confirm compliance with the ammonia limits.

4. Changed the SCR catalyst without obtaining a permit to construct. [Cogen A; Cogen B]

   The new Cormetech SCR catalyst appear to be performing as well as the original Hitachi catalyst. As discussed in the *Process Description* section of this evaluation, the Cogen Trains A and B continue to comply with existing NOx and NH3 emission limits with a comfortable margin of compliance. Therefore, the new catalyst do not cause an increase in the emission of either of these pollutants. The impact of the new catalyst on compliance with applicable rules and regulations is discussed in the *Rule Compliance Review* section below.

RULE COMPLIANCE REVIEW:

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The California Environmental Quality Act (CEQA), Public Resources Code Section 21000 et seq., requires that the environmental impacts of proposed “projects” be evaluated and that feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects be identified and implemented. The PRO project qualifies as a significant project so preparation of a CEQA document was required. The draft Environmental Impact Report (DEIR) for the PRO project was issued on March 6, 2008. The public review period for this document ended on April 22, 2008. The final Environmental Impact Report (FEIR) was certified on May 9, 2008. An addendum to the FEIR was certified on May 13, 2010.

The Cogen D related permit(s) will be issued with condition (S7.4) that specifies that Chevron shall comply with all applicable mitigation measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document which is part of the AQMD Certified Final Environmental Impact Report.

REGULATION II: PERMITS

RULE 212: STANDARDS FOR APPROVING PERMITS

212(c)(1): Public notice is required for a project if any of the modified permit units are located within 1000 feet of a school. As seen in Appendix F, the distance to the nearest school from the Cogen D stack is 2601 feet. Public notice is not required under this clause.

212(c)(2): Public notice is required for any "new or modified facility", which has on-site emission increases exceeding any of the daily maximums specified in subdivision (g) of Rule 212. The emission increase for the entire PRO Project, which includes proposed construction and modifications for the permit units listed in the table in the *PRO Project Overview* section of this evaluation, must be evaluated under this clause. The table below contains a comparison of the increase in estimated criteria pollutants emissions (controlled) for this project versus the emission increase thresholds contained in 212(g).

Air Contaminant	R212(g) Daily Maximum Threshold (lb/day)	Estimated Emission Increase (lb/day) (1)	
		Cogeneration D Train	Entire Project (2)
CO	220	142	379
NOx	40	195	-235
PM10	30	113	117
SO2	60	26	202
VOC	30	46	203
Lead	3	0	0

1) Increase in 30-day average maximum potential to emit. Includes emissions from commissioning, startup and shutdown.
2) Estimated emission increase for entire PRO Project from the PRO Project EIR.

Based on the estimated criteria emission increases shown in the EIR, a public notice is required since the estimated PRO Project emission increases for CO, NOX, PM10, SO2 and VOC each exceed the thresholds listed in 212(g). A public notice is required for each batch of permits issued for components of the PRO Project. A public notice has been issued for each of the three batches of PRO Project applications that have previously been proposed for issuance. The fourth public notice will include the following applications:

Equipment	Application No.
Cogeneration D Train	470782
Cogeneration D Train APCS	470783
Cogeneration A Train	474709
Cogeneration A Train APCS	512926
Cogeneration B Train	474711
Cogeneration B Train APCS	512927
Cogeneration C Train	410837
Cogeneration C Train APCS	405276
Auxiliary Boiler	474712

212(c)(3): Public notice is required for any new or modified permit units that have an increase in toxic air contaminants that results in an increase of maximum individual cancer risk (MICR) of more than one in a million (1×10^{-6}) during a lifetime (70 years). As discussed in additional detail in the evaluation of Rule 1401, none of the permit units included in this evaluation have an emission increase that results in an increase in MICR of more than 1×10^{-6} for any of the subject permit units. Public notice is not required under this clause.

212(g): 212(g) specifies that any new or modified sources subject to Regulation XIII which undergo construction or modifications resulting in an emissions increase exceeding any of the daily maximum emission thresholds (listed in the table above) will require notification. From Regulation XIII (Rule 1302), the definition of "Source" is any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility.

Public notice is required under this clause since the estimated CO, NOx, PM10 and VOC emissions for the Cogen D Train exceed the Rule 212(g) thresholds.

RULE 218 – CONTINUOUS EMISSION MONITORING

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 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.

Consistent with the three existing cogeneration units and the auxiliary boiler, the Cogen D Train will have a CO and a NOx CEMS on the exhaust stack. SO2 emissions are monitored through continuous measurement of fuel flow and the total reduced sulfur (TRS) concentrations of the fuel gas that is combusted in the turbine and duct burners. The TRS concentration of natural gas is not continuously monitored. Based on historical data, a TRS concentration of 4.91 ppmv is utilized in the quantification of SO2 emissions from the combustion of natural gas.

Only the CO CEMS is subject to the requirements of this regulation since the NOx and SO2 CEMS are subject to RECLAIM.

Requirements [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"

Chevron chose to certify, operate, and maintain the subject CO CEMS on the existing cogens according to the second (NSPS) option. The subject CO CEMS met all certification requirements and received certification from the District Source Test Group. A copy of the initial approval letter for the CO CEMS for each of the Cogens is contained in the engineering file.

Quality Assurance Procedures [40CFR60 Appendix F]: The CO CEMS are subject to Procedure 1 in this appendix. This procedure is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by a CEMS. One function of this procedure is to assess the quality of the CEMS data by estimating accuracy. The other function is to control the quality of the CEMS data by implementing QC policies and corrective actions. When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable.

Data Accuracy Assessment: Each CEMS must be audited at least once each calendar quarter. The audits shall be conducted as follows:

- Relative Accuracy Test Audit (RATA). A RATA must be conducted at least once every four calendar quarters. A RATA involves conducting a minimum of nine reference method (RM) test runs and comparing the results to CEMS data collected during each of the RM test runs.
- Cylinder Gas Audit (CGA). A CGA may be conducted in three of four calendar quarters, but in no more than three quarters in succession. In a CGA, the CEMS is challenged with two audit gases of known but different concentrations.
- Relative Accuracy Audit (RAA). An RAA may be conducted three of four calendar quarters, but in no more than three quarters in succession. The RAA utilizes the same procedures as a RATA except that only three sets of measurement data are required.

Chevron has been performing the required audits of the CO CEMS. Based on their history of compliance with this regulation for the existing CO CEMS, it is expected that Chevron will comply with the specified certification and QA/QC requirements for the CO CEMS on the Cogen D Train stack.

<u>REGULATION IV - PROHIBITIONS</u>

RULE 401: VISIBLE EMISSIONS

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 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 turbine will combust natural gas and the duct burner will combust natural gas and/or low sulfur refinery fuel gas. The cogen will be conditioned with emission limits for all CAPs including CO and NH_3. Also, Chevron has a long record of operating the three existing cogen units and Auxiliary Boiler within the limits of this rule. Compliance with this regulation is expected.

RULE 402: NUISANCE
This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property.

Nuisance is not expect since the subject turbine will combust natural gas and low sulfur refinery fuel gas and will be conditioned with emission limits for all CAPs including CO and NH_3. Also, Chevron has a long record of operating the three existing cogen units and the Auxiliary Boiler without causing nuisance. Compliance with this regulation is expected.

RULE 404: PARTICULATE MATTER - CONCENTRATION
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. As specified at 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 cogeneration units and auxiliary boiler are not subject to this regulation.

RULE 405: SOLID PARTICULATE MATTER - WEIGHT
This rule sets solid PM mass emission limits for the processing of solid materials. It is not applicable to combustion sources such as the subject cogeneration units and auxiliary boiler.

RULE 407: LIQUID AND GASEOUS AIR CONTAMINANTS
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 SO2; 15 minute average) [407(a)(2)(B)]

CO Limit
The existing cogeneration units are equipped with a CO catalyst for control of CO emissions and the permit for each of the units is conditioned with a CO emission limit of 10 ppmv (15% O2, 1-hr avg.). The Cogen D Train will be equipped with a CO catalyst and the permit will be conditioned with a CO emission limit of 2 ppmvd (15% O2, 1-hr avg.). According to the turbine manufacturer, maximum CO emissions during start-up and shutdown are expected to be 645 and 175 ppmvd (15% O2), respectively. Compliance with the 2000 ppmv CO limit is expected.

Sulfur Compound Limit:
The 500 ppmv sulfur compound limit is subsumed by RECLAIM [Rule 2001(j)] for the cogeneration unit, which will be classified as a major source under RECLAIM and will be equipped with an SO2 analyzer to comply with RECLAIM monitoring requirements.

RULE 409: COMBUSTION CONTAMINANTS
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).

PM/PM10 source tests were performed on the Auxiliary Boiler, Cogen A Train, Cogen B Train and Cogen C Train during April 2008. Summary results for these source tests are contained in the engineering file. As seen on the following table, the measured PM emissions for each of these units is less than the 0.1 gr/dscf limit of this regulation.

Source	Measured PM Emissions (gr/dscf)	Rule 409 PM Emission Limit (gr/dscf)	Rule 409 Compliant
Cogeneration A Train	0.0042	0.1	Yes
Cogeneration B Train	0.0035	0.1	Yes
Cogeneration C Train	0.0030	0.1	Yes
Auxiliary Boiler	0.0063	0.1	Yes

With the large margin of compliance for the existing cogeneration units, it is expected that the proposed Cogeneration D Train will also comply with the PM emission limit of this rule.

RULE 431.1: SULFUR CONTENT OF GASEOUS FUELS
This rule is subsumed by RECLAIM [Rule 2001(j)] for SOx RECLAIM facilities such as the Chevron Refinery.

RULE 474: FUEL BURNING EQUIPMENT – OXIDES OF NITROGEN
This rule is subsumed by RECLAIM [Rule 2001(j)] for NOx RECLAIM facilities such as the Chevron Refinery.

RULE 475: ELECTRIC POWER GENERATING EQUIPMENT
This rule applies to power generating equipment rated greater than 10 MW installed after May 7, 1976. Requirements specify that the equipment must comply with a PM mass emission limit of 11 lb/hr or a PM concentration limit of 0.01 grains/dscf. Compliance is demonstrated if either the mass emission limit or the concentration limit is met. As seen in the Rule 409 evaluation, PM emissions measured in the most recent source test of the existing cogeneration units are below 0.01 gr/dscf. Average PM emissions for the three cogeneration units during the source test were less than 7.5 lb/hr. Compliance with both of the PM emission limits of this regulation is expected.

RULE 476: STEAM GENERATING EQUIPMENT
The Auxiliary Boiler is subject to this rule. The duct burners are also subject to the requirements of this rule since they are used to produce steam, have a heat input rating of greater than 50 MMBtu/hr (each are ~ 120 MMBtu/hr), and were constructed after May 7, 1976. This regulation 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. As discussed for Rule 475, compliance of the new and existing cogeneration units with these PM limits is expected. The average PM emissions for the Auxiliary Boiler during the most recent source test were 0.0063 gr/dscf and 2.5 lb/hr. Compliance with the PM limits of this regulation is expected.

REGULATION IX - NEW SOURCE PERFORMANCE STANDARDS (NSPS)

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 unit of greater than 29 MW (100 million Btu/hour). The Auxiliary Boiler is an affected source. The heat recovery steam generators (HRSGs) on the existing cogeneration units are subject to this regulation since the duct burners fire at 120 MMBtu/hr and the cogen units were all constructed after 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).

The Auxiliary Boiler and the duct burners on the existing cogeneration units 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.

The Auxiliary Boiler and the duct burners on the existing cogen units combust only 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, the auxiliary boiler and the existing cogen duct burners 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 160 ppmv @ 3% O2 or 55 ppmv @ 15% O2. With proper operation of the SCR based NOx control systems on the Auxiliary Boiler and existing cogeneration units, 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.

40CFR60 SUBPART J- STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES

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. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery.

The Cogen A and B turbines are subject to this regulation when combusting butane and propane, which meet the definition of "fuel gas". The duct burners for all three Cogens are subject to this regulation when combusting refinery fuel gas (RFG), which also meets the definition of "fuel gas".

This regulation has a limit of 160 ppm H2S for any fuel gas combusted in a fuel gas combustion device. Propane and butane are seldom combusted in the turbines but the V-3140 fuel knockout drum, which supplies LPG to the A and B turbines, is equipped with a fuel sulfur GC for measurement of H_2S and total reduced sulfur (TRS) of the propane and butane when they are combusted in the turbines. Butane and Propane have very low sulfur concentration that is well below 160 ppmv. Continuous compliance with the 160 ppmv H2S limit on a 3-hour average basis is expected.

The RFG stream to the duct burners for the Cogen A and B Trains is supplied from the V-4540 fuel mix drum, which is equipped with a fuel sulfur GC for measurement of H_2S and TRS. This is the same refinery fuel gas stream that will be fed to the Cogen Train D duct burners. Chevron installed the No. 6 H2S plant in 2004 to reduce total sulfur concentrations in the fuel gas that is supplied to the V-1800 and V-4540 fuel mix drums. This plant reduces TRS concentrations to sub-40 ppmv levels through use of a DEA absorber for removal of H2S some carbonyl sulfide (COS), a merox scrubber for removal of C4SH and C5SH mercaptans and dimethyl-disulfide (DMDS), and a jet-wash column for removal of heavy mercaptans and other trace reduced sulfur compounds. The permit for the Cogen Train D will be conditioned with a BACT 40 ppmv (3-hr average) Total Reduced Sulfur (TRS) limit on this V-4540 refinery fuel gas stream. Compliance with both the 40-ppmv TRS and 160 ppmv H2S fuel gas limits is expected.

The RFG stream to the Cogen C train duct burners is supplied from the V-1000 fuel drum. This drum is also equipped with a fuel sulfur GC for measurement of H_2S and TRS. Chevron has supplied refinery fuel gas from this drum to the El Segundo Power Plant (ID 115663) in the past but is not current providing any gas to the power plant. For the months of June and July of 2010, the TRS concentration of this fuel gas stream average 19 ppmv. The maximum concentration on a 1-hr and 24-hr averaging basis was 53 ppmv and 28 ppmv. Continuous compliance with the 160 ppmv H2S limit of this regulation is expected.

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 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.

The Auxiliary Boiler and existing cogeneration units are not subject to this regulation because they have not been modified after May 17, 2007. The Cogen Train D gas turbine is not subject to this regulation because it will combust only commercial natural gas, which is produced outside of the refinery. The Cogen Train D duct burners will be subject to this regulation since they will combust natural gas and refinery fuel gas. The refinery fuel gas will be supplied to the duct burners from the V-4540 fuel mix drum, which also supplies fuel gas to the Cogen A and B Train duct burners.

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.). The duct burner exhaust gas is diluted by the exhaust gas from the gas turbine so Chevron must comply with the fuel gas H2S limits. As discussed above, Chevron installed the No. 6 H2S plant to achieve sub-40 ppmv TRS concentrations in the fuel gas sent to the V-4540 fuel mix drum. Compliance with the 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

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.

All three of the existing cogen turbines are subject to this NSPS since they all have a heat input (based on LHV) of greater than 10 MMBtu/hr and were constructed after Oct. 3, 1977. The proposed Cogen D turbine and duct heater are subject to 40CFR60 Subpart KKKK. According to §60.4305(b) in Subpart KKKK, turbines regulated under Subpart KKKK are exempted from the requirements of subpart GG. Therefore, the Cogen D Turbine is not subject to the requirements of this regulation.

A discussion of the applicable standards for this regulation follows.

NOx limit

Turbines that are subject to the NOx Limits of this regulation are specified at 40CFR60.332(b), (c), and (d) as follows:

- 60.332(b) – Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired…..
- 60.332(c) - Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired…
- 60.332(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b)…..

The definition of an e*lectric utility stationary gas turbine* at 60.331(q) is "any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale". The existing cogen units were constructed to supply electricity for refinery use only. They supply about 75% of the refinery's electrical power needs. Since the existing cogens are not *electric utility stationary turbine*s, they are not subject to the NOx limit under 60.332(b). The turbines are also not subject to the NOx limit under 60.332(c) and 60.332(d) since the heat input at peak load is greater than 100 MMbtu/hr and the rated base load is greater than 30 MW.

SOx limit

Each of the subject turbines are subject to the SOx limits of 60.333(a). The turbines must comply with one of the following limits:

- Exhaust gas concentration of 150 ppmv SO_2 (at 15% O_2, dry basis)
- Fuel sulfur limit of 0.8 percent (by weight) (8000 ppmw)

Chevron has chosen to comply with the 0.8% fuel sulfur limit. This limit is contained in permit condition B61.7. The turbines are permitted to combust natural gas, butane, pentane, or propane. The sulfur concentrations of these fuels are all well below 8000 ppmw. Compliance with this fuel sulfur limit is expected.

40CFR60 SUBPART GGG – STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOCS IN PETROLEUM REFINERIES

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 Auxiliary Boiler and Cogens 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.

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

This NSPS is applicable to affected facilities in refineries that begin construction 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 Cogen Train D is not a process unit as defined in this regulation. The Cogen D permit unit does not contain any compressors. For these reasons, the equipment in the Cogen Train D permit unit is not subject to the requirements of this regulation.

40CFR60 SUBPART KKKK: STANDARDS OF COMPLIANCE FOR STATIONARY COMBUSTION TURBINES

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 existing cogeneration units have not been modified or reconstructed after February 18, 2005 so they are not subject to this NSPS. The heat input capacity of the proposed Cogen D turbine is 508 MMBtu/hr (HHV) so it will be subject to the requirements of this regulation.

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% O2) since it has a heat input capacity between 50 and 850 MMBtu/hr and fires natural gas. This limit is well above the 2 ppmv NOx limit that will be imposed on the proposed cogeneration unit under Rule 2005 (BACT). The cogen 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 duct burner/HRSG (if applicable).

SOx Limit

The turbine is also subject to one of the following SO2 related limits:
(1) Exhaust gas with SO2 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. Historically, the TRS concentration of natural gas supplied to the refinery is less than 5 ppmv and the refinery fuel gas supplied to the duct burners will be conditioned with a 40 ppmv (1-hr average) TRS limit. These fuel sulfur concentrations are equivalent to 0.0008 lb SO2/MMBtu and 0.006 lb/MMBtu respectively. Compliance with the 0.006 lb SO_2/MMBtu limit of this regulation is expected.

Monitoring
A NOx analyzer is required under this regulation. The cogen unit will be required 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/100scf (for natural gas), then daily fuel monitoring is not required. The turbine will fire natural gas provided by the Southern California Gas Company which contains less than 1 grains-sulfur/100scf. Therefore, daily monitoring of the natural gas sulfur content is not required. Total reduced sulfur (TRS) content of the refinery fuel mix drum will be measured with a fuel sulfur GC to comply with RECLAIM. This fuel sulfur monitoring system will also satisfy the monitoring requirements of this NSPS.

<u>REGULATION X - NATIONAL EMISSION STANDARD FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)</u>

40CFR63 SUBPART CC: NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FROM PETROLEUM REFINERIES
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 contacting one or more of the hazardous air pollutants (HAPs) listed in Table 1 of this subpart.

The only sources in the existing and proposed cogeneration units must be evaluated as potential affected sources under this NESHAP are fugitive components in the refinery fuel gas, LPG, 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 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. Both the refinery fuel gas system and the LPG supply system qualify 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 existing and proposed cogeneration units are not subject to this regulation.

40CFR63 SUBPART YYYY: NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR STATIONARY COMBUSTION TURBINES

This NESHAP establishes emission limitations and operating limitations for HAP emissions from stationary combustion turbines located at major sources of HAP emissions. However, as specified in §63.6095, gas-fired stationary combustion turbines must comply only with the Initial Notification requirements set forth in §63.6145.

The emission and operating limits for gas turbines have been stayed until EPA takes final action on a proposal to delist lean premix gas-fired stationary combustion turbines and diffusion flame gas-fired stationary combustion turbines as source categories subject to NESHAP (MACT) standards. The proposed Cogen D turbine is a lean- premix type turbine and the existing cogen turbines are diffusion flame type turbines.

No additional analysis is required.

40CFR63 SUBPART DDDDD - NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR INDUSTRIAL, COMMERCIAL AND INSTITUTIONAL BOILERS AND PROCESS HEATERS

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. The public comment period for the proposed rule ends on August 23, 2010.

In the proposed regulation, *boiler* is defined as an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. *Waste heat boiler* is defined as a device that recovers normally unused energy and converts it to usable heat. Waste heat recovery 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.

Based on these definitions, the Auxiliary Boiler and the duct burners and associated heat recovery steam generators for the existing and proposed cogeneration units would be subject to the proposed regulation as boilers. The proposed regulation does not include a date that delineates between new and existing units so it is not currently possible to determine if the Cogen D duct burner/HRSG will be considered a new or existing unit. Existing units will be required to comply with the regulation within three years after the final rule is published in the federal register.

The proposed regulation defines eleven (11) subcategories of boilers and process heaters. The Auxiliary Boiler and cogeneration unit duct burners/HRSGs fit into the subcategory specified as *units designed to burn natural gas/refinery gas*. Emission limits for new and existing boilers and process heaters are specified in Tables 1 and 2 of the proposed regulation. The tables do not contain any emission limits for new or existing boilers or process heaters in the natural gas/refinery gas category. As specified in Table 3 of the proposed 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 Auxiliary Boiler and cogen unit burners/HRSGs 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 proposed regulation.

Due to a lack of emission limits, it is not expected that the regulation, as proposed, will have a significant impact on the design of the Aux. Boiler, existing cogen units, proposed cogen unit or associated air pollutions control systems. Based on past compliance with similar regulations, it is expected that Chevron would comply with this regulation as proposed. No changes to the permit or additional action are required at this time.

<u>REGULATION XI: SOURCE SPECIFIC STANDARDS</u>

RULE 1109: EMISSION OF OXIDES OF NITROGEN FROM BOILERS AND PROCESS EATERS IN PETROLEUM REFINERIES

Chevron is subject to the requirements of Regulation XX (RECLAIM), which supersedes the requirements of Rule 1109 per Rule 2001(j). Therefore, the Duct Burners/HRSGs are not subject to the requirements of Rule 1109.

RULE 1134: EMISSION OF OXIDES OF NITROGEN FROM STATIONARY GAS TURBINES

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 Cogen D turbine. The Cogen A and B turbines, which were constructed in 1986, would be subject to this regulation but the requirements of this rule has been subsumed by RECLAIM per 2001(j)

RULE 1135: EMISSION OF OXIDES OF NITROGEN FROM ELECTRIC POWER GENERATING SYSTEMS

The proposed and existing cogeneration systems are not subject to this regulation since they are not "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: EMISSION OF OXIDES OF NITROGEN FROM INDUSTRIAL, INSTITUTIONAL, AND COMMERCIAL BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

This regulation contains NOx and CO emission limits for certain boilers, steam generators, and process heaters. According to 1146(b), this rule applies to boilers, steam generators, and process heaters of equal to or greater than 5 million Btu per hour rated heat input capacity used in all industrial, institutional, and commercial operations with the exception of:

(1) boilers used by electric utilities to generate electricity; and

(2) boilers and process heaters with a rated heat input capacity greater than 40 million Btu per hour that are used in petroleum refineries; and

(3) sulfur plant reaction boilers.

The Auxiliary Boiler and the cogen duct burners/HRSGs are not subject to this regulation since they are used in a refinery and have a rated heat input capacity greater than 40

MMBtu/hr. Also, the NOx related requirements of this rule have been subsumed by RECLAIM per 2001(j) for RECLAIM facilities.

RULE 1173: CONTROL OF VOLATILE ORGANIC COMPOUND LEAKS FROM COMPONENTS OF PETROLEUM FACILITIES AND CHEMICAL PLANTS

This rule is intended to control volatile organic compound (VOC) leaks from fugitive components at refineries, chemical plants, oil and gas production fields, natural gas processing plants, and pipeline transfer stations. It contains identification requirements, leak standards, inspection requirements, maintenance and repair requirements, and recordkeeping and reporting requirements for fugitive components.

The only new components for the proposed Cogen D and existing components for the existing cogeneration trains that are subject to this regulation are those components that handle refinery fuel gas. Chevron has an existing fugitive emission component inspection and monitoring (I&M) program for compliance with the requirements of this rule. Where applicable, new components installed under this project will be integrated into this I&M program. Compliance with the requirements of this regulation is expected.

RULE 1176: SUMPS AND WASTEWATER SEPARATORS

The purpose of this rule is to limit VOC emissions from wastewater systems located at petroleum refineries, on-shore oil production fields, off-shore oil production platforms, chemical plants, and industrial facilities. The rule specifies requirements for wastewater sumps, separators, sewer lines, process drains, junction boxes, and air pollution control equipment.

The only modifications to Chevron’s wastewater systems under the subject applications will be the installation of new sewer lines and process drains. The process drains will be connected into existing junction boxes with new sewer lines. A summary of the requirements for sewer lines and process drains follows.

1176(e)(3) – Sewer Lines: All sewer lines shall be completely enclosed so that no liquid surface is exposed to the atmosphere. The manhole cover shall remain fully closed, except when opened for active inspection, maintenance, sampling, or repair.

1176(e)(4) – Process Drains: Any new process drain installed after September 13, 1996, shall be equipped with water seal controls or any other alternative control measure which is demonstrated by the applicant to be equivalent, or more effective than water seal controls in reducing VOC emissions, as approved in writing by the Executive Officer.

1176(f)(1)(B) – Monitoring: Chevron will monitor the process drains according to the frequency specified at 1176(f)(1)(B). The monitoring frequency is quarterly for accessible drains (except for non-emitting drains); semi-annual for non-emitting drains; and annual for inaccessible drains. According to 1176(f)(3), a drain must be repaired within 24 to 72 hours of a measured VOC concentration of 500 ppmv above background concentrations. Chevron will conduct this monitoring according to EPA Method 21 using an approved organic vapor analyzer (OVA).

Chevron has specified that the new drains will be equipped with water seal controls and that the drains will be added to their current Rule 1176 monitoring and inspection program. Compliance with this rule is expected.

REGULATION XIII - NEW SOURCE REVIEW

RULE 1303: REQUIREMENTS (December 6, 2002)

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 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. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility."

The South Coast Air Basin (SOCAB) is designated in attainment for CO, NOx and SOx. The following are currently considered nonattainment air contaminants: NOx, SOx, PM_{10}, and VOC. VOC & NOx are included since they are precursors for ozone. VOC, NOx, and SOx are included as PM-10 precursors. NOx and SOx emissions from RECLAIM Facilities are regulated under Regulation XX (RECLAIM). New Source Review requirements for NOx and SOx are specified in Rule 2005. For the subject applications, an evaluation must be performed for PM10, VOC, and ammonia. As specified in a Policy and Procedures memo from Mr. Mohsen Nazemi, Deputy Executive Officer for the District's Engineering and Compliance Office, combustion sources are subject to only the BACT requirements for CO.

1303(a)(1): Best Available Control Technology (BACT): 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 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 (AQMP) or rules adopted by the District Governing Board.

Cogeneration A, B and C Trains - The proposed permit condition changes do not cause an increase in the emission of any criteria pollutants for the existing cogeneration units so

BACT is not required. The following BACT was required and was implemented by Chevron during original construction of these cogeneration units:

- CO & VOC: Installation of a CO catalyst. Permit conditioned with a stack gas CO concentration limit of 10 ppmvd.
- NOx: Use of steam injection into the gas turbine and installation of SCR. Use of low-NOx duct burners. Permit conditioned with a stack gas NOx concentration limit of 9 ppmvd.
- PM10/SOx: Use of gaseous fuels in the turbines that are inherently low in sulfur such as natural gas and LPG. Use of natural gas and/or refinery fuel gas in the duct burners. For the Cogen Trains A and B, use of refinery fuel gas that complies with the 160 ppmv H2S limit of NSPS Subpart J. For the Cogen C Train, use of refinery fuel gas with a total reduced sulfur (TRS) concentration less than 100 ppmv.
- Ammonia: Ammonia slip concentration must be less than 20 ppmvd

Each of the cogen units are equipped with certified CO and NOx CEMs to show continuous compliance with the stack gas CO and NOx concentration limits. The V-3140 fuel mix drum, which supplies LPG to the Cogen Trains A and B, the V-4540 fuel drum, which supplies refinery fuel gas to the duct burners on the Cogen Trains A and B, and the V-1000 fuel drum, which supplies refinery fuel gas to the Cogen Train C duct burner, are each equipped with certified fuel sulfur gas chromatograph based semi-continuous emission monitoring systems to monitor TRS concentrations.

Auxiliary Boiler - The proposed permit condition changes do not cause an increase in the emission of any criteria pollutants for the Aux. Boiler so BACT is not required. The following BACT was required and was implemented by Chevron during original construction of the boiler:

- CO & VOC: Good combustion practice.
- NOx: Use of low NOx burners and SCR.
- PM10/SOx: Use of gaseous fuels (natural gas and /or refinery fuel gas). Refinery fuel gas must comply with the 160 ppmv H2S limit of NSPS Subpart J.
- Ammonia: Ammonia slip concentration must be less than 20 ppmvd.

The boiler stack is equipped with certified CO and NOx CEMs. The V-4540 fuel drum, which supplies refinery fuel gas to the boiler, is equipped with a certified fuel sulfur gas chromatograph based semi-continuous emission monitor system to monitor TRS concentrations of the refinery fuel gas.

Cogeneration D Train - The proposed Cogen Train D is a new source with an increase in emissions of CO, NOx, PM10, SOx, VOC and NH3. It is subject to BACT for CO, 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. The GE model PG6581 (Frame 6) turbine proposed for construction by Chevron will be operated on a combined cycle with HRSG and steam turbine. 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. Based on recently issued permits for combined cycle facilities including Magnolia Power (A/N 386305) and Vernon City Power (A/N 394164), AQMD has determined that BACT for combined cycle CGTs is as follows:

BACT (LAER) Requirements for Combined Cycle Gas Turbines

NOx	CO	VOC	PM_{10}/SOx	NH_3
2.0 ppmvd, @ 15% O_2, 1-hr avg.	2.0 ppmvd, @ 15% O_2, 1-hr avg.	2.0 ppmvd, @ 15% O_2, 1-hr avg.	Pipeline quality 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.	5.0 ppmvd @ 15% O_2, 1-hr avg.

The applicant is proposing the following emission levels for this project. The emission levels of NOx, CO, VOC, and NH3 in the table are manufacturer guaranteed emissions under normal operating conditions.

Proposed BACT (LAER) Levels for Chevron Cogen Train D

NOx	CO	VOC	PM_{10}/SOx	NH_3
2.0 ppmvd, @ 15% O_2, 1-hr avg.	2.0 ppmvd, @ 15% O_2, 1-hr avg.	2.0 ppmvd, @ 15% O_2, 1-hr avg.	Pipeline quality 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.	5.0 ppmvd, @ 15% O_2, 1-hr avg.

A NOx CEMS will be used to verify compliance with NOx BACT limit and a CO CEMS will be used to verify compliance with the CO BACT limit. The proposed control levels meet BACT requirements for the combined cycle gas turbine for all criteria pollutants including NH_3. Compliance with this rule is expected.

As discussed earlier, NOx, CO and VOC emissions are higher during startup and shutdown of the cogen unit because the SCR is not effective until the exhaust gas temperature at the SCR inlet reaches 597°F. Therefore, the BACT emission limits for these pollutants are not applicable during startup and shutdown. NOx, CO and VOC emissions during startups and shutdowns are minimized by conditioning the permit with a maximum time limit of 2 hours for each startup and shutdown. Startup and shutdown are defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597°F.

Fugitive Components: BACT for VOC service fugitive components is summarized below. The majority of fugitive components being installed are in natural gas service. These components are not considered to be in VOC service since natural gas contains less than 10% VOC.

- Valves**:** Bellow-sealed valves are required with the following exemptions.

    1. Heavy liquid service (i.e., streams with a vapor pressure <0.1 psia @ 100 °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.

Permit condition S31.20 specifies the requirement to install bellow-sealed (leakless) valves except for the exempt applications listed above. This condition also specifies that Chevron must submit a list of all non-leakless valves to the District prior to the startup of the cogeneration unit. It is also specified that Chevron shall not startup the equipment prior to the Districts approval for the use of all non-leakless valves.

- *Relief Valves*: BACT for emergency pressure relief valves (PRVs) is connection to a closed vent system. No new PRVs are being installed in this proposed permit unit.

- *Process Drain*: BACT for new process drains is installation of p-traps or seal pots and inclusion in an approved I&M program. According to Chevron, new process drains will be equipped with p-traps for VOC control.

- *Pumps*: BACT for pumps in light liquid service is double or tandem seals vented to a closed system and inclusion in an approved I&M program. BACT for pumps in heavy liquid service is single mechanical seals and inclusion in an approved I&M program. Chevron is installing two heavy liquid pumps. Each will be equipped with the required single mechanical seals.

- *Flanges*: BACT for new flanges is compliance with ANSI/API standards and inclusion in an approved I&M program. New flanges will comply with these requirements.

- *Compressors*: BACT for rotary compressors is an enclosed seal system connected to closed vent system and for centrifugal type is a seal system with a higher pressure barrier fluid. The only compressor being installed in this permit unit is a natural gas booster compressor, which is not subject to BACT.

1303(b) – The following requirements apply to any new or modified source which results in a net emission increase of any nonattainment air contaminant.

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 of BACT and modeling applicability. The modeling procedures are discussed in Appendix A to the rule.

It is specified in Appendix A of this rule that modeling is not required for VOC. Therefore, under this rule, 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, it is specified in an SCAQMD *Policies and Procedures* memo 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". A copy of this memo is contained in the engineering file.

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 116 lb/hr and 5.45 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. Modeling is required for NOx (NO_2). Chevron also performed modeling for CO and PM10 even through it was not required.

AQMD modeling staff reviewed the air quality modeling submitted by Chevron. Modeling staff provided their comments in a memorandum from Mr. Naveen Berry to Mr. Jay Chen dated May 19, 2010. A copy of this memorandum is contained in the engineering file. As noted in the memo, District modeling staff revised the modeling provided by Chevron to correct some deficiencies in the modeling. Using AERMOD in a screening analysis, District modeling staff determined that estimated ground level concentrations during shutdown were the most conservative.

Summary results of District Modeling Staffs analysis follows:

- CO – Peak 1-hour and 8-hour CO impacts plus the worst case background concentrations are 4,681 μg/m3 and 2,885 μg/m3, respectively. These impacts are less than the state 1-hour and federal 8-hour CO standards of 23,000 μg/m3 and 10,000 μg/m3, respectively.
- NO2 - Peak 1-hour and annual NO2 impacts plus the worst case background concentrations are 199 μg/m3 and 29.3 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.
- 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 0.60 μg/m3 and 0.20 μg/m3, which are less than the Rule 1202 significance thresholds of 2.5 μg/m3 and 1.0 μg/m3, respectively.

The US EPA established a new 1-hour NO2 standard of 0.100 ppm (188 μg/m3) that became effective on April 12, 2010. According to an interpretation by the District's Counsel Office, the AQMD is not yet designated as non-attainment for the new standard so a modeling analysis is not required for this new standard.

Compliance with the modeling requirements of this rule is achieved.

1303(b)(2): Offsets – Unless exempt from offsets requirements pursuant to Rule 1304, emission increases shall be offset by either Emission Reduction Credits approved pursuant to Rule 1309, or by allocations from the Priority Reserve.

PM10 Emission Offsets – As specified in an email from Mr. Jay Chen, Senior AQ Engineering Manager of the District's Refinery and Waste Management Permitting Group, 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 current combined maximum potential PM10 emissions for the Auxiliary Boiler, Cogen Train A and Cogen Train B is 578 lb/day based on the individual PM10 emission limits of 230 lb/day per permit condition A63.25 for the Auxiliary Boiler and 174 lb/day each for the Cogen Trains A and B per permit condition A63.12. To assure a reduction in combined maximum potential PM10 emissions of these existing permit units plus the proposed Cogen Train D, a permit condition that limits the combined PM10 emissions to 577 lb/day will be imposed on each of the permit units. Therefore, the proposed Cogen D Train qualifies for the concurrent facility modification offset exemption so PM10 ERCs are not required.

VOC Emission Offsets - As seen in the *Calculation* section, the estimated maximum potential VOC emissions for the Cogen Train D are 47.7 lb/day on a 30-day average basis. ERCs are calculated as the 30-day average PM10 emission increase multiplied by an ERC ratio of 1.2-to-1.0 for facilities in the South Coast Air Basin (SOCAB). Total VOC ERCs required for the project are 47.7 x 1.2 = 57.2 lb/day, which rounds down to 57 lb/day. Chevron currently has sufficient VOC ERC's to cover this 57 lb/day of offsets.

1303(b)(3) - Sensitive Zone Requirements: This section pertains to Emission Reduction Credits (ERCs) for facilities in the South Coast Air Basin (SOCAB). Except for credits that are obtained from the Priority Reserve, facilities are subject to the Sensitive Zone requirements (H&SC Section 40410.5) for ERCs. A facility in zone 1 may obtain ERCs originated in zone 1 only, and a facility in zone 2A may obtain ERCs from either zone 1 or zone 2A.

The El Segundo Refinery is located in Zone 1. Chevron will utilize ERC certificate no. AQ010935, which is for 170 lb/day of VOC. These ERCs were originally generated from the shutdown of equipment in 1994 at an ALCOA facility (ID. 017418) located in Vernon, which is in Zone 1. The equipment shutdown generated 566 lb/day of VOC ERCs issued as ERC certificates AQ001375 and AQ001497.

1303(b)(4) - Facility Compliance: The facility must be in compliance with all applicable rules and regulations of the District.

This facility is currently in compliance with all applicable rules and regulations. There are no outstanding NOV's and no known violations.

1303 (b)(5) - Major Polluting Facilities: Any new major polluting facility or major modification at an existing major polluting facility must comply with the requirements summarized below. A major modification is defined in 1302(r) as any modification at an existing major source that will cause

- an increase of one pound per day or more, of the facility's potential to emit (PTE) for NOx or VOC if the facility is located in the SOCAB , or
- an increase of 40 tons per year or more, of the facility's PTE for SOx, or
- an increase of 15 tons per year or more, of the facility's PTE for PM_{10}; or,
- an increase of 50 tons per year or more, of the facility's PTE for CO.

Since the increase in VOC emissions for the subject applications is greater than 1 lb/day, the proposed modifications are a major modification at a major polluting facility. Therefore, the project must comply with the following requirements.

(A) Alternative Analysis – Applicant must conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with that project.

As specified at 1303(b)(5)(D)(iii), the requirements for an alternative analysis under this subparagraph may be met through compliance with the California Environmental Quality Act if the proposed project has been analyzed by an environmental impact report pursuant to Public Resources Code Section 21002.1 and Title 14 California Code of Regulations Section 15080 et seq. As discussed earlier, the final EIR for the PRO Project, which was performed as required by CEQA, was certified on May 9, 2008. An addendum to the FEIR was certified on May 13, 2010. The requirements of 1303(b)(5)(A) are satisfied.

(B) Statewide Compliance: The applicant must demonstrate that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by the applicant in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act.

A letter from Mr. Jason Donchin, the Health, Environmental, and Safety Manager at the El Segundo Refinery, indicating that all major sources owned or operated by Chevron U.S.A. Inc. in California are in compliance or are on a schedule for compliance with all applicable standards emission limitations and standards under the Clean Air Act is contained in engineering file.

(C) Protection of Visibility - A modeling analysis for plume visibility is required if the net emission increase exceeds 15 tons/yr of PM10 or 40 tons/yr of NOx and the location of the source, relative to the closest boundary of a specified Federal Class I area, is within the distance specified in the table below.

Federal Class I Area	Threshold Distance	Distance from Chevron Refinery
Agua Tibia	28 km (17.4 miles)	135 km
Cucamonga	28 km (17.4 miles)	71 km
Joshua Tree	29 km (18.0 miles)	178 km
San Gabriel	29 km (18.0 miles)	50.5 km
San Gorgonio	32 km (19.9 miles)	133 km
San Jacinto	28 km (17.4 miles)	135 km

A plume visibility analysis is not required since none of the Federal Class I Areas are closer to the refinery than the distances specified in the table.

(D) Compliance through California Environmental Quality Act- As discussed previously, CEQA requirements have been fulfilled. (See CEQA Evaluation).

Regulation XIV - TOXICS AND OTHER NON-CRITERIA POLLUTANTS

Rule 1401: New Source Review of Carcinogenic Air Contaminants

Requirements – Rule 1401 contains the following requirements:

1) *(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.

2) *(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.
3) *(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 –

Permit Unit Basis**:** 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 HARP model (version 1.4a), which combines 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).

Toxic pollutant emissions from the proposed Cogeneration Unit D were estimated with emission factors developed from source testing of Chevrons Cogen Train A. These cogeneration unit TAC emission factors were developed for use in AB2588 emission inventories. Since the Cogen Train D and associated APCS is a similar design to the existing cogeneration units, these TAC emission factors are expected to be the best available factors for the proposed cogeneration unit. The TAC emission estimates, which are shown in the following table, are based on the maximum fuel consumption rate of 641 MMBTU/hr for the proposed turbine/duct burner.

Toxic Air Contaminant	Emission Factor (lb/MMBtu)	Estimated Emissions	
		lb/hr	lb/yr
ACETALDEHYDE	1.85E-05	1.19E-02	1.04E+02
BENZO(A)PYRENE	4.04E-09	2.59E-06	2.27E-02
BENZO(B)FLUORANTHENE	5.26E-09	3.37E-06	2.95E-02
BENZO(G,H,I)PERYLENE	1.35E-08	8.63E-06	7.56E-02
CADMIUM	4.40E-07	2.82E-04	2.47E+00
CHLOROFORM	1.06E-09	6.80E-07	5.96E-03
CHROMIUM (HEXAVALENT)	1.06E-09	6.80E-07	5.96E-03
COBALT	1.92E-07	1.23E-04	1.08E+00
COPPER	5.87E-06	3.76E-03	3.29E+01
LEAD	9.91E-07	6.35E-04	5.56E+00
MANGANESE	2.77E-06	1.78E-03	1.56E+01
MERCURY	4.90E-07	3.14E-04	2.75E+00
NAPHTHALENE	2.83E-07	1.81E-04	1.59E+00
NICKEL	2.24E-06	1.44E-03	1.26E+01
PHOSPHORUS	1.72E-05	1.10E-02	9.64E+01
SELENIUM	9.74E-07	6.24E-04	5.47E+00
VANADIUM	1.30E-07	8.34E-05	7.31E-01
ZINC	2.57E-05	1.65E-02	1.44E+02

The results from the analysis are shown in the table below. AQMD modeling staff reviewed the applicant's analyses for Rule 1401. Modeling staff provided their comments in a memorandum from Mr. Naveen Berry to Mr. Jay Chen dated May 19, 2010. 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.

Results of Rule 1401 Analysis

Parameter	Results	Rule 1401 Requirements	Comply (Y/N)
MICR	0.04EE-06	<1.0EE-06 (no TBACT) <10EE-06 (w/TBACT)	Yes
HIA	0.001	<1.0	Yes
HIC	0.003	<1.0	Yes
Cancer Burden	N/A	Applicable only if MICR >1.0EE-06	N/A

<u>Project Basis:</u> Under Rule 1401, a health risk assessment (HRA) is not required for the project as a whole. An HRA for the entire project was performed by Chevron for the Environmental Impact Report (EIR) that was prepared as required by CEQA. The HRA was prepared in accordance with the August 2003 Office of Environmental Health Hazard Assessment (OEHHA) *Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* as specified in the SCAQMD guidance for conducting a Tier 4 HRA to comply with Rule 1401 (SCAQMD, 2005b). The HRA was performed using the CARB HARP model (version 1.2a) that implements the OEHHA guidance (CARB, 2005b) following guidance in the HARP User's Guide (CARB, 2003).

The following table contains a summary of the PRO Project HRA results from Table 1 of Volume II of the Final EIR (SCH No. 2007081057) for the project.

Summary of Health Risks (from Final EIR)

Health Risk	Project HRA Result	CEQA Significance Threshold	Significant?
Increased Cancer Risk to the Maximum Exposed Individual Worker	0.22 in one million	10 in one million	No
Increased Cancer Risk to the Maximum Exposed Individual Resident	0.33 in one million	10 in one million	No
Increased Cancer Risk to the Maximum Exposed Sensitive Receptor	0.13 in one million	10 in one million	No
Maximum Chronic Non-Cancer HI	0.0066	1.0	No
Maximum Acute Non-Cancer HI	0.0307	1.0	No

<u>*Impact of Change of Cogen Train A and B SCR Catalyst*</u> – As discussed in the *Process Description* section, the new SCR catalyst that was installed in the heat recovery steam generators of the Cogen Trains A and B contains Vanadium Pentoxide, which is a Rule 1401 TAC, as an active component of the catalyst. The catalyst for the Cogen Train C and proposed Train D also contain this compound. This vanadium compound is impregnated into the catalyst and it is not volatile at the operating temperatures for the SCR. The only method by which significant amounts of the Vanadium Pentoxide could potentially be emitted to the

atmosphere is abrasion of the catalyst by solid PM in flue gas. Flue gas generated by gaseous fuel combustion contains very low levels of solid PM so the amount of catalyst abrasion is insignificant. Additionally, measured Cogen A and B Train ammonia concentrations for the last eight quarterly source tests were well below the 20 ppmv ammonia emission limit. Therefore, there are no quantifiable health impacts from the change in SCR catalysts.

REGULATION XVII - PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The PSD program is the federal New Source Review (NSR) program for 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, who is the Deputy Executive Officer of the AQMD 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 of the Auxiliary Boiler and Cogen Trains A and B were issued in 1986 so they were not subject to this regulation for original construction. They have also not been subject to this regulation for any subsequent permitting. Permit conditions A63.11 and A63.12, which include limits on annual NOx and SOx emissions, were imposed on the Cogen Trains A and B under A/Ns 388737 and 388738, respectively, to assure that the requirements of this regulation were not triggered.

With regards to the Cogen Train D, EPA evaluated PSD for the PRO Project because Chevron utilized an emission calculation methodology that is promulgated in 40 CFR 52.21 (NSR Reform) but not included in AQMD Regulation XVII. More specifically, Chevron utilized an actual-to-projected actual emissions methodology that follows the procedure for determining the "baseline actual emissions" that is described in 40 CFR 52.21(b)(48). In their PSD determination for the PRO project, Chevron asserted that the proposed Cogen D is not considered to be part of the PRO Project under PSD because they are neither technically not economically dependent on one another. Each can technically operate without the other, and both are economically viable as standalone projects." EPA concurred with Chevron's assertion so PSD for the Cogen D is evaluated separately from the PRO Project.

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, the Aux Boiler and Cogen Trains A and B 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. The Cogen Train C was 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 Cogen C Train was constructed. The proposed Cogen Train D is subject to BACT for CO, NOx and SOx under this regulation.

As discussed in the evaluation of Rule 1303, the existing cogens and the Auxiliary Boiler were constructed with BACT for CO, NOx and SOx and the proposed Cogen D 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 Cogen Train D versus the significance thresholds of the regulation is contained in the table below.

Pollutant	Emission Increase (ton/yr)	Significance Threshold (ton/yr)	Significant Increase of Attainment Pollutant?
CO	15	100	**No**
NOx	22	40	**No**
SOx	5	40	**No**

As seen in the table, the proposed Cogen Train D 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 Cogen Train D 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 2 ppmv; a fuel and heat input limit for the turbine of 508.7 MMBtu/hr of natural gas; and fuel and heat input limits for the duct burner of 132 MMBtu/hr of natural gas or refinery gas with a fuel sulfur limit of 30 ppmv (24-hr average). CO and NOx emissions during startups and shutdowns are limited through permit conditions that limit the total number of startups and shutdowns to 12 per year for maximum duration of 2 hours for each startup and 2 hours for each shutdown.

1703(a)(3)(A) – Certification of Compliance with Federally Enforceable Emission Limits and 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 visibility due to the project. *Not Applicable*

REGULATION XX - REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

RECLAIM is a market incentive program designed to allow facilities flexibility in achieving emission reduction requirements for Oxides of Nitrogen (NOx), and Oxides of Sulfur (SOx). The Chevron Refinery (ID 800030) is a Cycle II RECLAIM facility. The proposed cogeneration unit will be subject to the NOx and SOx requirements of this regulation.

RULE 2005: NEW SOURCE REVIEW FOR RECLAIM (Amended 5/06/05)

Sources that are subject to RECLAIM must comply with the New Source Review requirements of Rule 2005 instead of Regulation XIII.

2005 (c): Requirements for Existing Facilities

According to this section, a permit to construct (RECLAIM Facility Permit Amendment) cannot be approved for installation of a new source or modification of an existing source that results in an emission increase of NOx or SOx at an existing RECLAIM unless the following requirements are met:

1.) Best Available Control Technology is applied to the source [2005(c)(1)(A)]

2.) 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

3.) 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)].

According to 2005(d), "An increase in emissions occurs if a source's maximum hourly potential to emit immediately prior to the proposed modification is less than the source's post-modification maximum hourly potential to emit. The amount of emission increase will be determined by comparing pre-modification and post-modification emissions on an annual basis by using: (1) an operating schedule of 24 hours per day, 365 days per year; or (2) a permit condition limiting mass emissions."

Since the proposed Cogen D is a new source, there is an increase in both NOx and SOx emissions. As seen in the Calculation Section, the NOx and SOx emissions are estimated to be 50448 lb/year and 9056 lb/year, respectively.

BACT [2005(c)(1)(A)]: 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 Best Available Control Technology (BACT) will be applied to the source.

As discussed is the evaluation of Rule 1303, the existing cogens and the Auxiliary Boiler were constructed with BACT. The BACT determination for the proposed Cogen D is also contained in the Rule 1303 evaluation.

Modeling [2005(c)(1)(B)]: 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 the operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

According to Appendix A, 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 NO_2 is exceeded.

As discussed in the Rule 1303 evaluation, Chevron performed modeling that showed that the proposed Cogen Train D will not result in a significant increase in the air quality concentration for NO2

Reclaim Trading Credits [2005(c)(2)]: The applicant is required to demonstrate that they hold sufficient RTCs to offset the annual emission increase for the first year of operation using a 1-to-1 offset ratio.

The first full year of operation is expected to be July 2011 through Jun 2012 for this cycle 2 facility. Chevron currently holds 835 tons of NOx RTCs and 440 tons of SOx RTCs for the subject time period. According to Chevron's most recent APEP report, the refinery emitted 796 tons of NOx and 359 tons of SOx during the 2009 – 2010 cycle. Annual emissions of

NOx and SOx for the cogen are estimated at 21 ton/yr and 5 ton/yr, respectively. Also, it is expected that construction of the new SRU No. 73 will have been completed. Annual NOx and SOx emissions for the proposed SRU are estimated at 3 ton/yr and 18 ton/yr, respectively. NOx and SOx emissions for the refinery in the 2011-2012 cycle including the contribution of the new SRU and cogen are estimated at 820 ton/yr and 382 ton/yr. Based on these estimates, Chevron has adequate RTCs to cover the first full year of operation of the proposed cogeneration unit.

Additional Federal Requirements for Major Stationary Sources [2005(g)]: The Executive Officer shall not approve the application for a Facility Permit or an Amendment to a Facility Permit for a new, relocated or modified major stationary source, as defined in the Clean Air Act, 42 U.S.C. Section 7511a(e), unless the applicant complies with the requirements contained under this clause.

A major stationary source is defined as any facility which emits, or has the potential to emit 10 tons per year or more of NOx or 100 tons per year or more of SOx. The Chevron Refinery is a major stationary source since it has the potential to emit more than 10 ton/yr of NOx and 100 ton/yr of SOx. Compliance with the requirements under 2005(g) is required.

(1) *Statewide Compliance:* The applicant must certify that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards (42 U.S.C. Section 7503(a)(3))

A letter from Mr. Jason Donchin, the Health, Environmental, and Safety Manager for the El Segundo Refinery, indicating that all major sources owned or operated by Chevron Products Company in California are in compliance or are on a schedule for compliance with all applicable standards emission limitations and standards under the Clean Air Act is contained in the engineering file.

(2) *Alternative Analysis* – Applicant must conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstrate that the benefits of the proposed project significantly outweigh the environmental and social costs associated imposed as a result of its location, construction, or modification (42 U.S.C. Section 7503(a)(5));

It is specified at 2005(g)(3)(C), that "if the proposed project has been analyzed by an environmental impact report pursuant to Public Resources Code Section 21002.1 and Title 14 California Code of Regulations, Section 15080 et seq., paragraph (g)(2) shall be deemed satisfied." As discussed previously, the final EIR for this PRO Project was certified on May 9, 2008 and an addendum to the EIR was certified on May 13, 2010. The requirements of 2005(g)(2) are satisfied.

(4)(A): *Protection of Visibility* – the applicant shall conduct a modeling analysis for plume visibility in accordance with the procedures specified in Appendix B if the net emission increase from the new or modified source exceeds 40 tons/year of NOx; and the location of the source, relative to the closest boundary of a specified Federal Class I area, is within the distance specified in Table 4-1 of this rule.

As discussed in the Calculation Section, the estimated maximum potential to emit of NOx for the proposed cogeneration unit is 23 ton/year. Since the estimated increase in NOx emissions is less than the 40 ton/year threshold, visibility analysis is not required.

Public Notice [2005(h)]: - The applicant shall provide public notice, if required, pursuant to Rule 212 - Standards for Approving Permits.

As discussed in the Rule 212 evaluation, a public notice will be issued for the proposed permits.

Rule 1401 [2005(i)]: All new or modified sources shall comply with the requirements of Rule 1401 - New Source Review of Carcinogenic Air Contaminants, if applicable.

This modified source complies with the requirements of Rule 1401 (See R1401 analysis).

RULE 2011: REQUIREMENTS FOR MONITORING, REPORTING, AND RECORDKEEPING FOR OXIDES OF SULFUR (SOx) EMISSIONS (Amended 5/6/05)

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. The existing Auxiliary Boiler and each of the existing cogen turbines and the duct burners are RECLAIM Major SOx Sources that are subject to the maintenance, recordkeeping and reporting (MRR) requirements of this rule. The Cogen A and B Turbines are permitted to combust natural gas, butane, pentane, and propane. The Cogen C Turbine is permitted to combust natural gas. The duct burners for each of the Cogens are permitted to combust natural gas and/or refinery fuel gas.

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

For the existing boiler and cogeneration units, Chevron utilizes a SOx SCEMS consisting of fuel sulfur GCs and flow rate monitors on each of the subject fuel supplies. The butane, pentane, and propane (LPG) is supplied to the Cogen A and B turbines through the V-3140 fuel drum. The refinery fuel gas is supplied to the Cogen A and B duct burners from the V-4540 fuel mix drum and to the Cogen C duct burner from the V-1000 fuel drum. Each of these fuel drums are equipped with a certified fuel sulfur GC to measure the TRS concentration of the fuel provided to the Cogens. A copy of the CEMS certification for SCEMS for each of the existing boiler and cogeneration units is contained in the engineering file.

It is specified in 2011(f)(6) 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. Refinery fuel gas will be supplied to the Cogen Train D duct burners from the V-4540 fuel drum. The V-4540 fuel drum is already equipped with a certified fuel sulfur GC to measure fuel sulfur concentrations.

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, Chevron 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 (Amended 5/6/05)

This rule establishes the monitoring, reporting and recordkeeping requirements (MRR) for NOx emissions under the RECLAIM program. The Auxiliary Boiler, each of the cogen turbine, and the cogen duct burners are each classified as Major NOx sources that are subject to the MRR requirements of this rule. It is specified at Appendix A, Chapter 2.A.1. that 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 Auxiliary Boiler and existing cogeneration units utilize heat input and oxygen concentration to calculate NOx mass emissions. The approved NOx analyzer range is 0-25 ppmv. A copy of the SCAQMD CEMS certification for each of these CEMS is contained in the engineering file. The mass NOx emissions for the proposed Cogen Train D will also be monitored with a NOx CEMS including fuel flow meters.

RECLAIM NOx CEMS certification and QA/QC requirements are contained in Rule 2012, Appendix A, Chapter 2 and Attachment C. The primary independent quality control assessment is a semi-annual RATA performed by an independent source test company. Chevron has been performing the required RATAs for the NOx CEMS on the Auxiliary Boiler and existing cogeneration units. As mentioned above, the District's Source Test group routinely reviews the reports for these semi-annual RATAs.

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 *Calculation Section* of this evaluation. The NOx emissions during the commissioning period are primarily uncontrolled emissions but the turbine is not operating continually during this period.

The NOx emissions during normal operation are based on controlled emissions with the exception of one startup and shutdown per month.

It is also specified at 2011(c)(3)(A) and 2012(c)(3)(A) that a Facility Permit holder of a major SOx and NOx source shall install, maintain and operate a reporting device to electronically report total daily mass emissions of SOx and NOx and daily status codes to the District Central SOx and NOx Stations by 5:00 p.m. of the following day. Chevron currently performs this daily reporting for the Auxiliary Boiler and existing cogeneration units.

Based on Chevron'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

The initial Title V permit for the refinery was sent to Chevron on September 29, 2009 with an effective date of October 12, 2009. The permits issued for this project will be issued as a revision of the Title V permit. Permit revisions are categorized into the following four types: *administrative, minor, de minimis significant and significant*. The review and distribution requirements for each revision type are summarized in the following table.

Title V Permit Revisions: Review and Distribution Requirements

Revision Type	**Permit Review and Distribution Requirements**		
	EPA Review (45-day)	**Public Notice (30-day)**	**Send Final Permit to EPA**
Administrative	No	No	Yes
Minor	Yes	No	Yes
De Minimis Significant	Yes	No	Yes
Significant	Yes	Yes	Yes

According the definition in Rule 3000, a significant revision includes any of the following:

A) relaxation of any monitoring, recordkeeping, or reporting requirement, term, or condition in the Title V permit;
B) the addition of equipment or modification to existing equipment or processes that result in an emission increase of non-RECLAIM pollutants or hazardous air pollutants (HAP) in excess of any of the emission threshold levels in the following table:

De Minimis Emission Threshold Level

Air Contaminant	Daily Maximum (lb/day)
HAP	30
VOC	30
NO_x	40
PM-10	30
SO_x	60
CO	220

C) cumulative emission increases of non-RECLAIM pollutants or hazardous air pollutants from de minimis significant permit revisions during the term of the permit, in excess of any of the emission threshold levels in the table above. For the purposes of this subparagraph, the de minimis levels for HAP and VOC are not additive if the HAP is a VOC. The deminimis levels for HAP and PM-10 are not additive if the HAP is a PM-10. The HAP de minimis level in this section shall be superseded by any lower HAP de minimis level promulgated by the EPA Administrator, or;

D) any modification at a RECLAIM facility that results in an emission increase of RECLAIM pollutants over the facility's starting Allocation plus the nontradeable Allocations;

E) requests for a permit shield when such requests are made outside applications for initial permit or permit renewal issuance;

F) any revision that requires or changes a case-by-case evaluation of: reasonably available control technology (RACT) pursuant to Title I of the federal Clean Air Act; or maximum achievable control technology (MACT) pursuant to 40 CFR Part 63, Subpart B;

G) any revision that results in a violation of regulatory requirements;

H) any revision that establishes or changes a permit condition that the facility assumes to avoid an applicable requirement;

I) installation of new equipment subject to a New Source Performance Standard (NSPS) pursuant to 40 CFR Part 60, or a National Emission Standard for Hazardous Air Pollutants (NESHAP) pursuant to 40 CFR Part 61 or 40 CFR Part 63; or,

J) modification or reconstruction of existing equipment, resulting in an emission increase subject to new or additional NSPS requirements pursuant to 40 CFR Part 60, or to new or additional NESHAP requirements pursuant to 40 CFR Part 61 or 40 CFR Part 63.

This Title V revision qualifies as a significant revision for the following reasons:

1. Relaxation of monitoring conditions for the existing cogeneration units and associated APCSs;
2. Installation of a new equipment (Cogen D) that will be subject to an NSPS and NESHAP; and
3. Installation of new equipment (Cogen D) that results in an emission increase of non-RECLAIM pollutants in excess of threshold levels as seen in the table below.

Air Pollutant	De Minimis Emissions Threshold Level (lb/day)	Emission Increase for Proposed Title V Revision (lb/day)
VOC	30	46
PM10	30	113

ADDITIONAL FEDERAL REGULATIONS

40CFR PART 64 COMPLIANCE ASSURANCE MONITORING

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 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. For purposes of this regulation, a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of seals, lids, or roofs to prevent the release of pollutants, use of low-polluting fuel or feedstocks, or the use of combustion or other process design features or characteristics.

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 directly with the compliance limit.

The three existing cogeneration units and the proposed new cogeneration units 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 the existing cogeneration units, the NOx and CO CEMS specified in permit conditions D82.2 and D82.3, respectively, meet the definition for a continuous compliance determination method. For the proposed Cogen Train D, the NOx and CO CEMS specified in permit conditions D82.2 and D82.3, respectively, meet the definition for a continuous compliance determination method. Therefore, all of the cogeneration units are 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 units, 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 congeneration units, Auxilary Boiler, or proposed Cogen Train D.

40CFR PART 72 – ACID RAIN PROGRAM

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 Cogens) was constructed for the purpose of supplying 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) or (ii) (for post 11/15/1990 Cogens) 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 Chevron El Segundo 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 units.

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 Auxiliary Boiler, Cogen Trains A, B and C, and the associated APCSs. It is recommended that permits to construct be issued for the proposed Cogen Train D and associated APCS.

Appendix A: List of Chevron NOVs/NCs Issued Since January 1, 2008

NOTICE NO.	NOTICE TYPE	ISSUE DATE	STATUS	VIOLATION
P48119	NOV	1/10/2008	Closed on 11/25/08	FAILURE TO OPERATE F-105 AND F-205 ABOVE 1400 DEG F PER CONDITION B163.5 IN THE FACILITY PERMIT TO OPERATE, ID# 800030.
P48123	NOV	1/29/2008	Closed on 9/2/08	1) Discharge of air contaminants > 40% opacity into the atmosphere for more than three minutes in one hour from K-25. (2) Discharge of air contaminants > 20% opacity into the atmosphere for more than three minutes in one hour from K-25.
P48124	NOV	2/24/2008	Closed on 9/2/08	Failure to ensure all vent gases from the SNR were vented to the co control ground flare (C4116) during the SNR startup per Administrative Condition #4 in Section# of the Permit to Operate, ID# 800030.
P52764	NOV	4/12/2008	Closed on 11/25/08	F/P 800030, PROCESS 5 SYSTEM 1 - OPERATING CONTRARY TO CONDITION S15.10
P12140	NOV	7/29/2008	Closed on 5/19/09	VOC LEAKS >50000 PPM RULE 1173 (d)(1)(B) - 9 COUNTS. 40 CFR FF 61.344(a)(1)(i(A) MEASURABLE LEAKS FROM SEPARATOR COVER > 500 PPM - 4 COUNTS.
P12141	NOV	7/30/2008	Closed on 5/19/09	VOC LEAKS GREATER THAN 50,000 PPM - 21 COUNT VIOLATION RULE 1173(d)(1)(B)
P12142	NOV	7/31/2008	Closed on 5/19/09	OPEN ENDED LINES IN CRUDE #2 LSFO - I COUNT. 40 CFR 61.346(b)(1) PROCESS DRAIN WITHOUT WATER SEAL CONTROL.
P48721	NOV	10/2/2008	Closed on 6/18/09	1) Failure to operate refinery flare in a smokeless manner; 2) Exceeding Ringlemann 2 emissions for more than 5 minutes in one hour. (FCC Flare)
D05317	NC	4/24/2009	In Compliance	PROVIDE INFORMATION REGARDING EMERGENCY POWER CAPACITY AND PROTOCOL DURING POWER OUTAGES BY THE UTILITIES.
P48724	NOV	6/22/2009	In Compliance	EXCEEDING 20 PPMV EMISSION LIMIT ON SELECTIVE CATALYTIC REDUCTION UNIT (DEVICE C2217) ON AUXILIARY BOILER (DEVICE D2216)
D05319	NC	7/10/2009	In Compliance	PROVIDE SOURCE TEST RESULTS FOR AUXILIARY BOILER N43.

NOTICE NO.	NOTICE TYPE	ISSUE DATE	STATUS	VIOLATION
D05320	NC	1/20/2010	In Compliance	REPORT VARIOUS AND PROCESS EQUIPMENT ACCORDING TO PROCESS UNIT GUIDELINES.
P48725	NOV	2/23/2010	In Compliance	1) Light service leak in excess of 50,000 ppm - 1 count, (2) Leak at water separator cover exceeding 500ppm - 13 counts, (3) Equipment operating contrary to permit conditions and not in good operating condition - 2 counts.
P48726	NOV	2/23/2010	In Compliance	Equipment not in good operating condition - 3 counts.
P48727	NOV	2/23/2010	In Compliance	Light service leaks in excess of 50,000 ppm - 2 counts.
P48728	NOV	3/02/2010	In Compliance	EMISSIONS FROM WASTE SYSTEM IN EXCESS OF 500 PPM - 4 COUNTS.

Appendix B: Cogen Train D - Estimate of Criteria Pollutant Emissions During Startup

Pollutant	Elapsed Time (minutes)	Fuel Gas Rate MMBTU/Hr	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
NOx	0-15	68	Uncontrolled	12.0	ppmv @ 15% O2	0.0449379	0.8
NOx	16-30	135	Uncontrolled	25.0	ppmv @ 15% O2	0.0936205	3.2
NOx	31-45	135	Uncontrolled	25.0	ppmv @ 15% O2	0.0936205	3.2
NOx	46-60	228	Uncontrolled	45.0	ppmv @ 15% O2	0.1685169	9.6
NOx	61-75	415	Uncontrolled	15.0	ppmv @ 15% O2	0.0561723	5.8
NOx	76-90	509	Uncontrolled	15.0	ppmv @ 15% O2	0.0561723	7.1
NOx	91-105	509	Controlled	3.0	ppmv @ 15% O2	0.0112345	1.4
NOx	106-120	509	Controlled, BACT	2.0	ppmv @ 15% O2	0.0074896	1.0
						Total	**32**
SO2	0-15	68	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.0
SO2	16-30	135	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.0
SO2	31-45	135	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.0
SO2	46-60	228	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.0
SO2	61-75	415	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.1
SO2	76-90	509	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.1
SO2	91-105	509	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.1
SO2	106-120	509	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.1
						Total	**0.50**
VOC	0-15	68	Uncontrolled	25.2	ppmvd @ 15% O2	0.0328242	0.6
VOC	16-30	135	Uncontrolled	6.6	ppmvd @ 15% O2	0.0085968	0.3
VOC	31-45	135	Uncontrolled	6.6	ppmvd @ 15% O2	0.0085968	0.3
VOC	46-60	228	Uncontrolled	15.3	ppmvd @ 15% O2	0.0199290	1.1
VOC	61-75	415	Uncontrolled	7.7	ppmvd @ 15% O2	0.0100296	1.0
VOC	76-90	509	Uncontrolled	8.2	ppmvd @ 15% O2	0.0106809	1.4
VOC	91-105	509	Controlled	4.4	ppmvd @ 15% O2	0.0057312	0.7
VOC	106-120	509	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0026051	0.3
						Total	**5.7**
CO	0-15	68	Uncontrolled	126.0	ppmv @ 15% O2	0.2872115	4.8
CO	16-30	135	Uncontrolled	33.0	ppmv @ 15% O2	0.0754500	2.5
CO	31-45	135	Uncontrolled	33.0	ppmv @ 15% O2	0.0754500	2.5
CO	46-60	228	Uncontrolled	76.5	ppmv @ 15% O2	0.1743784	10.0
CO	61-75	415	Uncontrolled	38.5	ppmv @ 15% O2	0.0877591	9.1
CO	76-90	509	Uncontrolled	41.0	ppmv @ 15% O2	0.0934577	11.9
CO	91-105	509	Controlled	9.0	ppmv @ 15% O2	0.0205151	2.6
CO	106-120	509	Controlled, BACT	2.0	ppmv @ 15% O2	0.0045589	0.6
						Total	**44**
PM10	0-15	68	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.1
PM10	16-30	135	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
PM10	31-45	135	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
PM10	46-60	228	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.4
PM10	61-75	415	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.7
PM10	76-90	509	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.9
PM10	91-105	509	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.9
PM10	106-120	509	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.9
						Total	**4.5**

Notes and Assumptions:

Uncontrolled NO_x, CO and VOC concentration estimates provided by Fluor.

The duct burners are fired only after the gas turbine is at base load operation.

High Heating Value of Fuel Gas = 1050 Btu/scf; F-factor = 8710 scf/MMBtu; Molar Volume = 379 scf/mole

Appendix C: Cogen Train D - Estimate of Criteria Pollutant Emissions During Shutdown

Pollutant	Elapsed Time (minutes)	Fuel Gas Rate (MMBtu/hr)	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
NOx	0-15	471.4	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0074896	0.9
NOx	16-30	396.7	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0074896	0.7
NOx	31-45	322.0	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0074896	0.6
NOx	46-60	247.3	Uncontrolled	40	ppmvd @ 15% O2	0.1497928	9.3
NOx	61-75	172.5	Uncontrolled	48	ppmvd @ 15% O2	0.1797514	7.8
NOx	76-90	135.0	Uncontrolled	35	ppmvd @ 15% O2	0.1310687	4.4
NOx	91-105	135.0	Uncontrolled	35	ppmvd @ 15% O2	0.1310687	4.4
NOx	106-120	87.8	Uncontrolled	17	ppmvd @ 15% O2	0.0636620	1.4
						Total	**29**
SO2	0-15	471.4	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.09
SO2	16-30	396.7	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.08
SO2	31-45	322.0	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.06
SO2	46-60	247.3	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.05
SO2	61-75	172.5	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.03
SO2	76-90	135.0	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.03
SO2	91-105	135.0	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.03
SO2	106-120	87.8	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.02
						Total	**0.4**
VOC	0-15	471.4	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0026051	0.3
VOC	16-30	396.7	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0026051	0.3
VOC	31-45	322.0	Controlled, BACT	29.0	ppmvd @ 15% O2	0.0377738	3.0
VOC	46-60	247.3	Uncontrolled	95.0	ppmvd @ 15% O2	0.1237419	7.7
VOC	61-75	172.5	Uncontrolled	116.0	ppmvd @ 15% O2	0.1510954	6.5
VOC	76-90	135.0	Uncontrolled	89.0	ppmvd @ 15% O2	0.1159266	3.9
VOC	91-105	135.0	Uncontrolled	89.0	ppmvd @ 15% O2	0.1159266	3.9
VOC	106-120	87.8	Uncontrolled	45.0	ppmvd @ 15% O2	0.0586146	1.3
						Total	**27**
CO	0-15	471.4	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0045589	0.5
CO	16-30	396.7	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0045589	0.5
CO	31-45	322.0	Uncontrolled	145	ppmvd @ 15% O2	0.3305211	26.6
CO	46-60	247.3	Uncontrolled	474	ppmvd @ 15% O2	1.0804622	66.8
CO	61-75	172.5	Uncontrolled	579	ppmvd @ 15% O2	1.3198051	56.9
CO	76-90	135.0	Uncontrolled	445	ppmvd @ 15% O2	1.0143580	34.2
CO	91-105	135.0	Uncontrolled	445	ppmvd @ 15% O2	1.0143580	34.2
CO	106-120	87.8	Uncontrolled	223	ppmvd @ 15% O2	0.5083187	11.2
						Total	**231**
PM10	0-15	471.4	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.8
PM10	16-30	396.7	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.7
PM10	31-45	322.0	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.6
PM10	46-60	247.3	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.4
PM10	61-75	172.5	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.3
PM10	76-90	135.0	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
PM10	91-105	135.0	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
PM10	106-120	87.8	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
						Total	**3.5**

Notes and Assumptions:

Uncontrolled NO_x, CO and VOC concentration estimates provided by Fluor.

Duct burner is shutdown prior to gas turbine shutdown.

Fuel to Gas Turbine prior to shutdown = 508.7 MMBTU/Hr

High Heating Value of Fuel Gas = 1050 Btu/scf; F-factor = 8710 scf/MMBtu; Molar Volume = 379 scf/mole

Appendix D: Cogen Train D - Estimated NOx and SO2 Emissions During Comissioning Period

Day	Operation	Duration (hours)	Fuel Gas Rate (mmbtu/hr)	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
NOx								
1	Bring to FSNL	0.5	135	Uncontrolled	14.0	ppmvd @ 15% O2	0.05243	3.5
1	OST Check	2.0	135	Uncontrolled	30.0	ppmvd @ 15% O2	0.11235	30.3
1	Shut Down	0.5	90	Uncontrolled	30.0	ppmvd @ 15% O2	0.11235	5.1
2	Bring to FSNL	0.5	135	Uncontrolled	14.0	ppmvd @ 15% O2	0.05243	3.5
2	Sync. Checks	6.0	135	Uncontrolled	30.0	ppmvd @ 15% O2	0.11235	91.0
2	Shut Down	0.5	90	Uncontrolled	30.0	ppmvd @ 15% O2	0.11235	5.1
3	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
3	Combustion Tuning	10.0	508.7	Uncontrolled	18.0	ppmvd @ 15% O2	0.06741	342.9
3	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
4	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
4	Combustion Tuning	10.0	508.7	Uncontrolled	18.0	ppmvd @ 15% O2	0.06741	342.9
4	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
5	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
5	Duct Burner Testing	10.0	640.7	Uncontrolled	16.0	ppmvd @ 15% O2	0.05991	383.8
5	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
6	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
6	Duct Burner Testing	10.0	640.7	Uncontrolled	16.0	ppmvd @ 15% O2	0.05991	383.8
6	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
7	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
7	Duct Burner Testing	10.0	640.7	Uncontrolled	16.0	ppmvd @ 15% O2	0.05991	383.8
7	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
12	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
12	NH3 Inj. Testing	22.5	640.7	"Controlled"	16.0	ppmvd @ 15% O2	0.05991	863.6
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	16.0	ppmvd @ 15% O2	0.05991	921.2
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	16.0	ppmvd @ 15% O2	0.05991	921.2
14	NH3 Inj. Testing	24.0	640.7	"Controlled"	16.0	ppmvd @ 15% O2	0.05991	921.2
							Total	**5862**
SO2								
1	Bring to FSNL	0.5	135	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.05
1	OST Check	2.0	135	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.22
1	Shut Down	0.5	90	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.04
2	Bring to FSNL	0.5	135	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.05
2	Sync. Checks	6.0	135	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.65
2	Shut Down	0.5	90	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.04
3	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.30
3	Combustion Tuning	10.0	508.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	4.10
3	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
4	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
4	Combustion Tuning	10.0	508.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	4.10
4	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
5	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
5	Duct Burner Testing	10.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	5.16
5	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
6	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
6	Duct Burner Testing	10.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	5.16
6	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
7	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
7	Duct Burner Testing	10.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	5.16
7	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
12	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
12	NH3 Inj. Testing	22.5	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	11.60
13	NH3 Inj. Testing	24.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	12.38
13	NH3 Inj. Testing	24.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	12.38
14	NH3 Inj. Testing	24.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	12.38
15							**Total**	**74**

Appendix D (Cont'd): Cogen Train D - Estimated CO & VOC Emissions During Comissioning Period

Day	Operation	Duration (hours)	Fuel Gas Rate (mmbtu/hr)	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
Carbon Monoxide								
1	Bring to FSNL	0.5	135	Uncontrolled	151.0	ppmvd @ 15% O2	0.34420	23.2
1	OST Check	2.0	135	Uncontrolled	40.0	ppmvd @ 15% O2	0.09118	24.6
1	Shut Down	0.5	90	Uncontrolled	151.0	ppmvd @ 15% O2	0.34420	15.5
2	Bring to FSNL	0.5	135	Uncontrolled	151.0	ppmvd @ 15% O2	0.34420	23.2
2	Sync. Checks	6.0	135	Uncontrolled	40.0	ppmvd @ 15% O2	0.09118	73.9
2	Shut Down	0.5	90	Uncontrolled	151.0	ppmvd @ 15% O2	0.34420	15.5
3	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
3	Combustion Tuning	10.0	508.7	Uncontrolled	18.0	ppmvd @ 15% O2	0.04103	208.7
3	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
4	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
4	Combustion Tuning	10.0	508.7	Uncontrolled	18.0	ppmvd @ 15% O2	0.04103	208.7
4	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
5	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
5	Duct Burner Testing	10.0	640.7	Uncontrolled	17.0	ppmvd @ 15% O2	0.03875	248.3
5	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
6	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
6	Duct Burner Testing	10.0	640.7	Uncontrolled	17.0	ppmvd @ 15% O2	0.03875	248.3
6	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
7	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
7	Duct Burner Testing	10.0	640.7	Uncontrolled	17.0	ppmvd @ 15% O2	0.03875	248.3
7	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
12	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
12	NH3 Inj. Testing	22.5	640.7	"Controlled"	17.0	ppmvd @ 15% O2	0.03875	558.6
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	17.0	ppmvd @ 15% O2	0.03875	595.9
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	17.0	ppmvd @ 15% O2	0.03875	595.9
14	NH3 Inj. Testing	24.0	640.7	"Controlled"	17.0	ppmvd @ 15% O2	0.03875	595.9
							Total	**4270**
Volatile Organic Compounds								
1	Bring to FSNL	0.5	135	Uncontrolled	30.0	ppmvd @ 15% O2	0.03907	2.6
1	OST Check	2.0	135	Uncontrolled	7.9	ppmvd @ 15% O2	0.01029	2.8
1	Shut Down	0.5	90	Uncontrolled	30.0	ppmvd @ 15% O2	0.03907	1.8
2	Bring to FSNL	0.5	135	Uncontrolled	30.0	ppmvd @ 15% O2	0.03907	2.6
2	Sync. Checks	6.0	135	Uncontrolled	7.9	ppmvd @ 15% O2	0.01029	8.3
2	Shut Down	0.5	90	Uncontrolled	30.0	ppmvd @ 15% O2	0.03907	1.8
3	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
3	Combustion Tuning	10.0	508.7	Uncontrolled	1.9	ppmvd @ 15% O2	0.00247	12.6
3	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
4	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
4	Combustion Tuning	10.0	508.7	Uncontrolled	1.9	ppmvd @ 15% O2	0.00247	12.6
4	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
5	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
5	Duct Burner Testing	10.0	640.7	Uncontrolled	3.0	ppmvd @ 15% O2	0.00391	25.0
5	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
6	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
6	Duct Burner Testing	10.0	640.7	Uncontrolled	3.0	ppmvd @ 15% O2	0.00391	25.0
6	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
7	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
7	Duct Burner Testing	10.0	640.7	Uncontrolled	3.0	ppmvd @ 15% O2	0.00391	25.0
7	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
12	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
12	NH3 Inj. Testing	22.5	640.7	"Controlled"	3.0	ppmvd @ 15% O2	0.00391	56.3
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	3.0	ppmvd @ 15% O2	0.00391	60.1
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	3.0	ppmvd @ 15% O2	0.00391	60.1
14	NH3 Inj. Testing	24.0	640.7	"Controlled"	3.0	ppmvd @ 15% O2	0.00391	60.1
							Total	**394**

Appendix D (Cont'd): Cogen Train D - Estimated PM10 Emissions During Comissioning Period

Day	Operation	Duration (hours)	Fuel Gas Rate (mmbtu/hr)	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
1	Bring to FSNL	0.5	135	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.5
1	OST Check	2.0	135	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	1.9
1	Shut Down	0.5	90	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.3
2	Bring to FSNL	0.5	135	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.5
2	Sync. Checks	6.0	135	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	5.8
2	Shut Down	0.5	90	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.3
3	Bring to Base Load	1.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	3.0
3	Combustion Tuning	10.0	508.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	36.1
3	Shut Down	0.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.9
4	Bring to Base Load	1.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	3.0
4	Combustion Tuning	10.0	508.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	36.1
4	Shut Down	0.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.9
5	Bring to Base Load	1.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	3.0
5	Duct Burner Testing	10.0	640.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	45.5
5	Shut Down	0.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.9
6	Bring to Base Load	1.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	3.0
6	Duct Burner Testing	10.0	640.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	45.5
6	Shut Down	0.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.9
7	Bring to Base Load	1.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	3.0
7	Duct Burner Testing	10.0	640.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	45.5
7	Shut Down	0.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	0.9
12	Bring to Base Load	1.5	Varies	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	3.0
12	NH3 Inj. Testing	22.5	640.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	102.4
13	NH3 Inj. Testing	24.0	640.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	109.2
14	NH3 Inj. Testing	24.0	640.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	109.2
15	NH3 Inj. Testing	24.0	640.7	NG Emisison Fact.	0.00710	lbs/MMBTU	0.00710	109.2
							Total	**670**

Notes and Assumptions:

Uncontrolled NO_x, CO and VOC concentration estimates provided by Fluor Corporation.

Higher Heating Value of Fuel Gas = 1050 Btu/scf; F-factor = 8710 scf/MMBtu; Molar Volume = 379 scf/mole

Appendix E: Cogen Train D - VOC Emission Estimate for Fugitive Components

Equipment Type	Service	No. of Sources	Controlled Emission Factors lbs/yr*	Annual ROG Emission lbs/yr
Valves	HC Vapor	0	23	0
	Bellows Sealed	0	0	0
Valves	Fuel Gas	5	12	60
	Bellows Sealed	32	0	0
Valves	Light Liquid	0	19	0
	Bellows Sealed	0	0	0
Valves	Heavy Liquid	45	3	135
	Bellows Sealed	0	0	0
Flanges	Light Liquid/Vapor	210	1.5	315
Flanges	Heavy Liquid	84	1.5	126
Connectors	Light Liquid/Vapor	66	1.5	99
Connectors	Heavy Liquid	24	1.5	36
Pumps	Light Liquid	0	104	0
Pumps	Heavy Liquid	2	80	160
	(Non-Rule 1173)			
Pumps	< 10% HC	0	104	0
	(Non-Rule 1173)		(520 x 0.2= 104)	
Compressors	HC Gas/Vapor	0	514	0
Compressors	< 10% HC	0	51.4	0
	(Non-Rule 1173)		(514 x 0.1 = 51.4)	
PRV's Heavy Liquid (To Atmosphere)		0	1,135	0
PRV's Heavy Liquid (Closed System)		2	0	0
PRV's Light Liquid/Vapor (To Atmosphere)		0	1,135	0
PRV's Light Liquid/Vapor (Closed System)		2	0	0
Drains		6	80	480
(non-emergency, without watercseal and venting to atmosphere)				
	Total Count:	478	Total (lb/yr)	**1,411.0**
			Hydrocarbon Emissions (lbs/day)	**3.9**

Appendix F: Distance from Cogen Train D to Sensitive Receptors

Receptor No.	Receptor Name	UTME	UTMN	Distance to Cogen D Stack (ft)
SR001	ST ANTHONY'S SCHOOL	369950	3753775	3069
SR002	IMPERIAL SCHOOL	369775	3755100	6719
SR003	EL SEGUNDO MIDDLE	369275	3754500	4563
SR004	EL SEGUNDO PRESCHOOL	369350	3753900	**2601**
SR005	ST JOHNS LUTHERAN	370250	3754850	6516
SR006	CAROUSEL CHRISTIAN	369075	3754200	3649
SR007	1ST BAPTIST CHURCH DAY CARE	369750	3754575	5037
SR008	BEGG SCHOOL	371700	3750625	11345
SR009	LA MARINA	372125	3750600	12410
SR010	MEADOWS AVE SCHOOL	371425	3750500	11051
SR011	PACIFIC ELEMENTARY	370375	3750525	9189
SR012	CENTER SCHOOL	370250	3750475	9192
SR013	AMERICAN MARTYRS SCHOOL	370200	3750725	8366
SR014	GRAND VIEW SCHOOL	369475	3751150	6453
SR015	MANHATTAN HILLS SCHOOL	372025	3749875	13886
SR016	AVIATION HIGH SCHOOL	372875	3750450	14632
SR017	LADERA SCHOOL	369600	3751250	6180
SR018	MED CENTER OF MANHATTAN BEACH	370975	3751200	8345
SR019	MONTESSORI OF MANHATTAN BEACH	371775	3749725	13765
SR020	LITTLE RED SCHOOL HOUSE	371825	3750400	12162
SR021	1ST LUTHERAN CIRCLE OF LOVE	370625	3750275	10271
SR022	MANHATTAN BEACH ELE/MIDDLE	370275	3750425	9374
SR023	CAMP RUNAROUND INC	369600	3751175	6423
SR024	YOUNG VISIONS	369650	3751325	5968
SR025	RAINBOW RIVER	370300	3750375	9556
SR026	CENTER STREET ELEMENTARY	370275	3754500	5585

Note: UTM Coordinates for Cogen Train D Stack are UTME - 369293 and UTMN - 3753109