SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 99	PAGE 1
OFFICE OF ENGINEERING AND COMPLIANCE	APPL. NO. 467141, etc.	DATE 11/19/09
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY: Bob Sanford	CHECKED BY KN

CHEVRON PRO PROJECT

Application Nos. 467141, 470738, 470739, 480558, 482504, 482505, 498947, 499500, 499877 & 499878

PERMIT TO CONSTRUCT

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 A, B, & D Trains 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, 2009.
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	Proposed Batch No. 3: Applications being evaluated in this document.
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: Applications to be included in a subsequent evaluation.
 10/17/07 10/17/07 10/17/07	Change of Permit Condition for: Cogen A Train Cogen B Train Auxiliary Boiler	60	 474709 474711 474712	
3/2/07	Construct No. 2 Crude Unit Flare and Vapor Recovery System (VRS)	10	466152 466151	Proposed Batch No. 5: Applications to be included in a subsequent evaluation.
  6/1/07 6/1/07 6/1/07 12/6/07	Connect existing pressure relief valves to the new Flare/VRS for: • No. 2 Crude Unit • No. 2 Resid Stripper • Merox Plant • Waste Gas Compressors K450A/B	50	 469934 469936 469935 476228	
4/26/07	Construct LPG Tank No. 722	10	468538	Applications on hold at Chevron's request pending their internal project review
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) Application Type: 10 = New Construct; 50 = Alteration of Existing Permit Unit; 60 = Change of Condition

SWS/SRU PROJECT SUMMARY

As part of their PRO Project, Chevron is proposing to construct a new sour water stripper (SWS) with the capacity to treat 330 gpm (11,300 bbl/day) of sour water fed from existing sour water tanks. The acid gas from the new SWS will be fed to a new sulfur recovery unit (SRU), which will be equipped with an amine-based tail gas treatment unit (TGTU) followed by an incinerator and SOx scrubber. The new SRU, which will have the capacity to produce 235 long tons per day (LTPD) of sulfur when processing amine acid gas only and 175 LTPD when processing amine and ammonia acid gas, will supplement three existing refinery SRUs, which have a total capacity of 675 LTPD. A mass balance for the new SRU/TGTU is shown in Appendix H. Based on this mass balance, the H2S concentration of the amine and ammonia acid gas fed to the SRU is expected to be around 77% and 25% (vol), respectively, when the SWS is in operation. The NH3 concentration of the amine and ammonia acid gas is estimated to be 0% and 47%, respectively.

The new SRU will be unique in its ability to treat acid gas with high ammonia concentrations. For this reason, the new SWS, which will primarily process high ammonia sour water, will be equipped and permitted to feed ammonia acid gas to only the new SRU. The ammonia processing (destruction) capacity of the new SRU when processing ammonia acid gas from the new SWS is 35 tons per day.

The existing Refinery Blowdown Gas Recovery System and LSFO Emergency Relief System (Flare) are included in this evaluation because the new SWS, SRU and TGTU will contain pressure relief valves (PRVs) that Chevron proposes to connect to these existing systems. The three existing refinery SRUs are included in this evaluation because the construction of the new SRU will be a modification of the existing refinery sulfur recovery plant under 40 CFR 60 Subpart Ja. SRU Nos.10, 20 and 70, which are currently subject to NSPS Subpart J will become subject to NSPS Subpart Ja.

EQUIPMENT DESCRIPTION:

The proposed permits to construct will be issued in Section H of the Chevron's RECLAIM/Title V Facility Permit. The equipment descriptions and permit conditions that will be included in the RECLAIM/Title V Facility Permit are contained in this section. In these proposed permit pages, new text is indicated by underline and deleted text is indicated by strikeout. For existing permit units, the applicable pages from Chevron's current RECLAIM Facility Permit are contained in Appendix A of this evaluation. For all of these existing permit units, a permit to construct in Section H of the Chevron's RECLAIM FP is acting as the temporary permit to operate.

Section H: Permit to Construct and Temporary Permit to Operate

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 12: TREATING AND STRIPPING PROCESSES					
System 28: SOUR WATER STRIPPER PLANT NO. 68					S7.4, S13.2, S15.21, S31.20, S56.1

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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	
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3/26/07	Construct Sour Water Stripper	10	467141	Proposed Batch No. 3: Applications being evaluated in this document.
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: Applications to be included in a subsequent evaluation.
 10/17/07 10/17/07 10/17/07	Change of Permit Condition for: Cogen A Train Cogen B Train Auxiliary Boiler	60	 474709 474711 474712	
3/2/07	Construct No. 2 Crude Unit Flare and Vapor Recovery System (VRS)	10	466152 466151	Proposed Batch No. 5: Applications to be included in a subsequent evaluation.
  6/1/07 6/1/07 6/1/07 12/6/07	Connect existing pressure relief valves to the new Flare/VRS for: • No. 2 Crude Unit • No. 2 Resid Stripper • Merox Plant • Waste Gas Compressors K450A/B	50	 469934 469936 469935 476228	
4/26/07	Construct LPG Tank No. 722	10	468538	Applications on hold at Chevron's request pending their internal project review
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) Application Type: 10 = New Construct; 50 = Alteration of Existing Permit Unit; 60 = Change of Condition

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Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
PIT, SULFUR, T-101, WITH STEEL COVER, WITH EMERGENCY VENT TO ATMOSPHERE, WIDTH: 15 FT; DEPTH: 9 8 FT 5 IN; LENGTH: 25 FT **A/N: ~~449360~~ 499500**	D917	D911	Note: No modification	H2S: 10 PPMV (5) [RULE 468, 10-8-1976] ; SOX: 500 PPMV (5) [RULE 407, 4-2-1982]	
BLOWER, K-102, AIR, COMMON TO SRU NOS. 10 AND 20 **A/N: ~~449360~~ 499500**	D918		Note: No modification		
BLOWER, K-202, AIR, COMMON TO SRU NOS 10 AND 20 **A/N: ~~449360~~ 499500**	D936		Note: No modification		
KNOCK OUT POT, H2S, V-601, (COMMON TO CLAUS UNITS 10, 20, 70 AND 73), HEIGHT: 12 FT 6 IN; DIAMETER: 5 FT **A/N: ~~449360~~ 499500**	D961				
BLOWER, K-101, MAIN REACTION AIR, COMMON TO SRU NOS. 10 AND 20 **A/N: ~~449360~~ 499500**	D3459		Note: No modification		
BLOWER, K-201, MAIN REACTION AIR, COMMON TO SRU NOS. 10 AND 20 **A/N: ~~449360~~ 499500**	D3461		Note: No modification		
CONDENSER, E-101, SULFUR NO. 1 **A/N: ~~449360~~ 499500**	D3713		Note: No modification		
CONDENSER, E-102, SULFUR NO. 2 **A/N: ~~449360~~ 499500**	D3714		Note: No modification		
CONDENSER, E-104, SULFUR NO. 3 **A/N: ~~449360~~ 499500**	D3715		Note: No modification	H2S: 10 PPMV (5) [RULE 468, 10-8-1976] ; HAP: (10) [40CFR 63 Subpart UUU, #4, 2-9-2005] SOX: 500 PPMV (5) [RULE 407, 4-2-1982]; ~~SO2: 250 PPMV (8) [40CFR 60 Subpart J,6-24-2008]~~; SO2: 250 PPMV (8) [40CFR 60 Subpart Ja, 6-24-2008]	
BLOWER, MK-802, AIR, ELECTRIC MOTOR-DRIVEN, SPARE UNIT, COMMON TO SRU NOS. 10 AND 20 **A/N: ~~449360~~ 499500**	D3835		Note: No modification		E71.27
KNOCKOUT POT, V-600, ACID GAS, (COMMON TO CLAUS UNITS 10, 20, 70, AND 73), T/T LENGTH: 20 FT; DIAMETER: 5 FT **A/N: 449360 499500**	D4089		Note: No modification		
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~449360~~ 499500**	D3654		Note: No modification		H23.3

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
FILTER, K-6801 AND K-6801A, SOUR WATER PREFILTERS, TWO FILTERS IN PARALLEL,T/T, LENGTH: 8 FT 6 IN; DIA: 3 FT A/N 467141	D4305				K171.17
VESSEL, V-6801, SOUR WATER OIL SEPARATOR, T/T, LENGTH: 10 FT; DIA: 3 FT A/N 467141	D4306				K171.17
COLUMN, C-6810, SOUR WATER STRIPPER, 330 GPM, T/T, HEIGHT: 122 FT; DIAMETER: 5 FT A/N 467141	D4307				K171.17
ACCUMULATOR, V-6820, OVERHEAD, T/T, LENGTH: 10 FT; DIA: 3 FT 6 IN A/N 467141	D4308				K171.17
TANK, AMMONIUM BISULFIDE, 500 GAL, PART OF APS INJECTION PACKAGE PK-6801 A/N 467141	D4309				K171.17
FUGITIVE EMISSION, MISCELLANEOUS A/N 467141	D4310				H23.3

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 13: Sulfur Production					P13.1
System 1: Sulfur Recovery – Claus Unit No. 10					S7.3, S13.12, S15.15, S18.1
FURNACE, COMBUSTION CHAMBER AND REACTION, F-101, 26 MMBTU/HR A/N: ~~449360~~ 499500	D908		Note: No modification		
BURNER, F-102, AUXILIARY BURNER NO. 1, LENGTH: 8 FT; DIAMETER: 2 FT 2 IN A/N: ~~449360~~ 499500	D909		Note: No modification		
BURNER, F-103, AUXILIARY BURNER NO. 2, LENGTH: 8 FT; DIAMETER: 2 FT 2 IN A/N: ~~449360~~ 499500	D910		Note: No modification		
REACTOR, SULFUR CONVERTER, R-101A/B, TWO-STAGE CATALYTIC, LENGTH: 52 FT; DIAMETER: 10 FT A/N: ~~449360~~ 499500	D915		Note: No modification		

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
CONDENSER, E-204, SULFUR NO. 4 **A/N: ~~454962~~ 499877**	D3718		Note: No modification	H2S: 10 PPMV (5) [RULE 468, 10-8-1976] ; HAP: (10) [40CFR 63 Subpart UUU, #4, 2-9-2005] SOX: 500 PPMV (5) [RULE 407, 4-2-1982]; ~~SO2: 250 PPMV (8) [40CFR 60 Subpart J,6-24-2008]~~; <u>SO2: 250 PPMV (8) [40CFR 60 Subpart Ja, 6-24-2008]</u>	
BLOWER, MK-802, AIR, ELECTRIC MOTOR-DRIVEN, SPARE UNIT, COMMON TO SRU NOS. 10 AND 20 **A/N: ~~449360~~ 499500**	D3835		Note: No modification		E71.27
KNOCKOUT POT, V-600, ACID GAS, (COMMON TO CLAUS UNITS 10, 20, 70 <u>AND 73</u>), T/T LENGTH: 20 FT; DIAMETER: 5 FT **A/N: ~~449360~~ 499500**	D4089		Note: No modification		
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~454962~~ 499877**	D3655		Note: No modification		H23. 3

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 13: Sulfur Production					P13.1
System 4: Sulfur Recovery – Claus Unit No. 70					S7.3, <u>S13.12</u>, S15.17, S18.1
FURNACE, F-701, COMBUSTION CHAMBER AND REACTION, 62. 4 MMBTU/HR **A/N: ~~454963~~ 499878**	D954		Note: No modification		
REACTOR, SULFUR CONVERTER, R-701A/B.TWO-STAGE CATALYTIC,LENGTH: 42 FT; DIAMETER: 14 FT **A/N: ~~454963~~ 499878**	D958		Note: No modification		
PIT, T-701, SULFUR, WITH STEEL COVER, WITH EMERGENCY VENT TO ATMOSPHERE, WIDTH: 25 FT 3 IN; DEPTH: 5 FT 9 IN; LENGTH: 52 FT 4. 5 IN **A/N: ~~454963~~ 499878**	D960	D955	Note: No modification	H2S: 10 PPMV (5) [RULE 468, 10-8-1976] ; SOX: 500 PPMV (5) [RULE 407, 4-2-1982]	
KNOCK OUT POT, H2S, V-601, <u>(COMMON TO CLAUS UNITS 10, 20, 70 AND 73)</u> , HEIGHT: 12 FT 6 IN; DIAMETER: 5 FT **A/N: ~~454963~~ 499878**	D961		Note: No modification		

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 13: Sulfur Production					P13.1
System 2: Sulfur Recovery – Claus Unit No. 20					S7.3, S13.12, S15.16, S18.1
BLOWER, K-102, AIR, COMMON TO SRU NOS. 10 AND 20 **A/N: ~~449360~~ 499500**	D918		Note: No modification		
FURNACE, F-201, COMBUSTION CHAMBER AND REACTION, 26 MMBTU/HR **A/N: ~~454962~~ 499877**	D924		Note: No modification		
BURNER, AUXILIARY BURNER NO. 1, F-202, IN-LINE **A/N: ~~454962~~ 499877**	D925		Note: No modification		
BURNER, AUXILIARY BURNER NO. 2, F-203, IN-LINE **A/N: ~~454962~~ 499877**	D926		Note: No modification		
REACTOR, SULFUR CONVERTER, R-201A/B, TWO-STAGE CATALYTIC, LENGTH: 52 FT; DIAMETER: 10 FT **A/N: ~~454962~~ 499877**	D931		Note: No modification		
PIT, T-201, SULFUR, WITH STEEL COVER, WITH EMERGENCY VENT TO ATMOSPHERE, WIDTH: 15 FT; DEPTH: ~~9~~ 8 FT 5 IN; LENGTH: 25 FT **A/N: ~~454962~~ 499877**	D934	D927	Note: No modification	H2S: 10 PPMV (5) [RULE 468, 10-8-1976] ; SOX: 500 PPMV (5) [RULE 407, 4-2-1982]	
BLOWER, K-202, AIR, COMMON TO SRU NOS 10 AND 20 **A/N: ~~449360~~ 499500**	D936		Note: No modification		
KNOCK OUT POT, H2S, V-601, (COMMON TO CLAUS UNITS 10, 20, 70 AND 73), HEIGHT: 12 FT 6 IN; DIAMETER: 5 FT **A/N: ~~449360~~ 499500**	D961				
BLOWER, K-101, MAIN REACTION AIR, COMMON TO SRU NOS. 10 AND 20 **A/N: ~~449360~~ 499500**	D3459		Note: No modification		
BLOWER, K-201, MAIN REACTION AIR, COMMON TO SRU NOS. 10 AND 20 **A/N: ~~449360~~ 499500**	D3461		Note: No modification		
CONDENSER, E-201, SULFUR NO. 1 **A/N: ~~454962~~ 499877**	D3716		Note: No modification		
CONDENSER, E-202, SULFUR NO. 2 **A/N: ~~454962~~ 499877**	D3717		Note: No modification		

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 13: SULFUR PRODUCTION					P13.1
System 10: SULFUR RECOVERY - CLAUS UNIT NO. 73					S1.5, S7.4, S13.12, S15.22, S18.20, S56.1
DRUM, V-7301, AMINE ACID GAS KO, T/T, HEIGHT: 10 FT 9 IN; DIAMETER: 5 FT **A/N 470738**	D4311				K171.17
DRUM, V-7302, NH3 ACID GAS KO, T/T, HEIGHT: 8 FT 3 IN; DIAMETER: 3 FT 6 IN **A/N 470738**	D4312				K171.17
BLOWER, K-7301 AND K-7301A (ONE SPARE), COMBUSTION AIR, ELECTRIC, 791 MSCFH, 750 HP **A/N 470738**	D4313				K171.17
FURNACE, F-7301, COMBUSTION CHAMBER AND REACTION, 92 MMBTU/HR BOILER, WASTE HEAT, E-7301, UNFIRED **A/N 470738**	D4314	D4323			K171.17
CONDENSER, E-7302, SULFUR NO. 1 **A/N 470738**	D4315				K171.17
DRUM, V-7308, NO. 1 SULFUR SEAL, HEIGHT: 2 FT 6IN; DIAMETER: 2 FT **A/N 470738**	D4316				K171.17
REACTOR, NO. 1 SULFUR CONVERTER, R-7301, CATALYTIC, T/T, LENGTH: 21 FT 6 IN; DIAMETER: 12 FT **A/N 470738**	D4317				K171.17
CONDENSER, E-7303, SULFUR NO. 2 **A/N 470738**	D4318				K171.17
DRUM, V-7309, NO. 2 SULFUR SEAL, HEIGHT: 2 FT 6IN; DIAMETER: 2 FT **A/N 470738**	D4319				K171.17
REACTOR, NO. 2 SULFUR CONVERTER, R-7302, CATALYTIC, T/T, LENGTH: 21 FT 6 IN; DIAMETER: 12 FT **A/N 470738**	D4320				K171.17
CONDENSER, E-7304, SULFUR NO. 3 **A/N 470738**	D4321			H2S: 2.5 PPMV (4) [RULE 2005, 5-6-2005]; H2S: 10 PPMV (5) [RULE 468,10-8-1976]; HAP: (10) [40CFR 63 SUBPART UUU, #3,4-11-2002]; SOX: 12 PPMV (4)	K171.17, A195.15, A195.16

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Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
KNOCK OUT POT, SO2 RECYCLE GAS, V-701, HEIGHT: 8 FT; DIAMETER: 3 FT **A/N: ~~454963~~ 499878**	D962		Note: No modification		
EJECTOR, SULFUR PIT GAS EDUCTOR, K-702 **A/N: ~~454963~~ 499878**	D967		Note: No modification		
KNOCK OUT POT, V-777, SOUR WATER **A/N: ~~454963~~ 499878**	D2149		Note: No modification		
BURNER, AUXILIARY NO. 1, F-702, ACID GAS, IN-LINE **A/N: ~~454963~~ 499878**	D3466		Note: No modification		
BURNER, AUXILIARY NO. 2, F-703, ACID GAS, IN-LINE **A/N: ~~454963~~ 499878**	D3467		Note: No modification		
BLOWER, K-701, PROCESS AIR **A/N: ~~454963~~ 499878**	D3468		Note: No modification		
CONDENSER, E-701, SULFUR NO. 1, HEIGHT: 53 FT; DIAMETER: 7 FT 7 IN **A/N: ~~454963~~ 499878**	D3719		Note: No modification		
CONDENSER, E-702, SULFUR NO. 2, HEIGHT: 53 FT; DIAMETER: 7 FT 7 IN **A/N: ~~454963~~ 499878**	D3720		Note: No modification		
CONDENSER, E-703, SULFUR NO. 3, HEIGHT: 53 FT; DIAMETER: 7 FT 7 IN **A/N: ~~454963~~ 499878**	D3721		Note: No modification	H2S: 10 PPMV (5) [RULE 468, 10-8-1976] ; HAP: (10) [40CFR 63 Subpart UUU, #4, 2-9-2005] SOX: 500 PPMV (5) [RULE 407, 4-2-1982]; ~~SO2: 250 PPMV (8) [40CFR 60 Subpart J, 6-24-2008]~~; SO2: 250 PPMV (8) [40CFR 60 Subpart Ja, 6-24-2008]	
BLOWER, MK-801, AIR, ELECTRIC MOTOR-DRIVEN, SPARE UNIT **A/N: ~~454963~~ 499878**	D3836		Note: No modification		E71. 28
KNOCKOUT POT, V-600, ACID GAS, (COMMON TO CLAUS UNITS 10, 20, 70 AND 73), T/T LENGTH: 20 FT; DIAMETER: 5 FT **A/N: ~~449360~~ 499500**	D4089		Note: No modification		
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~454963~~ 499878**	D3656		Note: No modification		H23. 3

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Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
A/N 470739					
FURNACE, F-7303, REDUCING GAS GENERATOR, T/T, LENGTH: 16 FT 1 IN; DIAMETER: 7 FT 2 IN BURNER, F-7306, 12.8 MMBTU/HR A/N 470739	D4329				K171.17
REACTOR, R-7303, HYDROGENATION, T/T, LENGTH: 23 FT; DIAMETER: 12 FT A/N 470739	D4330				K171.17
BLOWER, K-7034 AND K-7034A (ONE SPARE), BOOSTER, 1030 MSCFH, 950 HP A/N 470739	D4331				K171.17
CONDENSER, C-7301, SUPERHEATER/CONTACT, T/T HEIGHT: 74 FT 2 IN; DIAMETER: 9 FT 6 IN A/N 470739	D4332				K171.17
ABSORBER, C-7302, AMINE, T/T, HEIGHT: 61 FT; DIAMETER: 8 FT 6 IN A/N 470739	D4333	C4344			E336.15, K171.17
COLUMN, C-7303, AMINE REGENERATOR, T/T, HEIGHT: 101 FT 10 IN; DIAMETER: 6 FT 6 IN A/N 470739	D4334				K171.17
DRUM, V-7314, REGENERATOR REFLUX, T/T, HEIGHT: 8 FT 10 IN, DIAMETER: 3 FT	D4335				K171.17
STORAGE TANK, T-7303, AMINE, HEIGHT: 18 FT; DIAMETER: 12 FT A/N 470739	D4336				K171.17
TANK, T-7302, LEAN AMINE SURGE TANK, HEIGHT: 21 FT 6 IN; DIAMETER: 20 FT A/N 470739	D4337				K171.17
FILTER, K-7306A/B/C, LEAN AMINE, THREE TOTAL, T/T, HEIGHT: 6 FT 10 IN; DIAMETER: 3 FT A/N 470739	D4338				K171.17
FILTER, K-7305, AMINE DRAIN, T/T, HEIGHT: 6 FT 10 IN; DIAMETER: 1 FT 2 IN A/N 470739	D4339				K171.17
DRUM, V-7312, AMINE DRAIN, T/T, HEIGHT: 11 FT; DIAMETER: 5 FT 6 IN A/N 470739	D4340				K171.17

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
				[RULE 2005, 5-6-2005]; SO2: 250 PPMV (8) [40CFR 60 Subpart Ja, 6-24-2008]; SOX: 500 PPMV (5) [RULE 407,4-2-1982]	
DRUM, V-7310, NO. 3 SULFUR SEAL, T/T, HEIGHT: 2 FT 6 IN; DIAMETER: 2 FT A/N 470738	D4322				K171.17
VESSEL, T-7301, LIQUID SULFUR, T/T, LENGTH: 24 FT; DIAMETER: 8 FT A/N 470738	D4323	D4314		H2S: 10 PPMV (5) [RULE 468,10-8-1976]; SOX: 500 PPMV (5) [RULE 407,4-2-1982]	K171.17
EJECTOR, G-7301, SULFUR VESSEL GAS EJECTOR, USES 150 PSIG STEAM A/N 470738	D4324				K171.17
COLUMN, C-7305, SULFUR DEGASSING, T/T, HEIGHT: 34 FT; DIAMETER: 2 FT 6 IN A/N 470738	D4325				K171.17
COMPRESSOR, K-7302 AND K-7302A (ONE SPARE), PROCESS AIR BOOSTER TO SULFUR DEGASSING UNIT, ELECTRIC, 4.2 MSCFH, 7.5 HP A/N 470738	D4326				K171.17
SUMP, S-7301, STORM WATER, LENGTH: 36 FT; WIDTH 16 FT; DEPTH: 16 FT A/N 470738	D4327				K171.17
KNOCK OUT POT, H2S, V-601, (COMMON TO CLAUS UNITS 10, 20, 70 AND 73) , HEIGHT: 12 FT 6 IN; DIAMETER: 5 FT A/N: ~~449360~~ 499500	D961				
KNOCKOUT POT, V-600, ACID GAS, (COMMON TO CLAUS UNITS 10, 20, 70 AND 73), T/T LENGTH: 20 FT; DIAMETER: 5 FT A/N: ~~449360~~ 499500	D4089				

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 13: SULFUR PRODUCTION					P13.1
System 11: TAIL GAS TREATMENT UNIT NO. 73					S7.4, S15.21, S18.21, S31.20, S56.1
BLOWER, K-7303 AND K-7303A (ONE SPARE), RGG COMBUSTION AIR, 105.4 MSCFH, 23.1 HP	D4328				K171.17

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 20: Air Pollution Control					
System 7: LSFO Emergency Relief System (Flare)					~~S7.3~~, S7.4 S13.2, S18.7
FLARE, ELEVATED WITH STEAM INJECTION, F-2500, HEIGHT: 175 FT; DIAMETER: 3 FT 6 IN **A/N: ~~454964~~ 482505**	C1757		Note: No modification		B61.11, D12.14, D323.2, H23.44, H23.46, I1.1
DRUM, V-1198, CRUDE UNIT RELIEF, WITH STEAM COIL, LENGTH: 20 FT; DIAMETER: 11 FT 6 IN **A/N: ~~454964~~ 482505**	D1759		Note: No modification		
DRUM, V-1290, NAPHTHA HYDROTREATER RELIEF, WITH STEAM COIL, LENGTH: 16 FT; DIAMETER: 5 FT **A/N: ~~454964~~ 482505**	D1760		Note: No modification		
DRUM, V-1591, VRDS RELIEF, WITH STEAM COIL, LENGTH: 32 FT; DIAMETER: 10 FT 6 IN **A/N: ~~454964~~ 482505**	D1761		Note: No modification		
DRUM, V-1691, VGO RELIEF, WITH STEAM COIL, LENGTH: 30 FT; DIAMETER: 10 FT 6 IN **A/N: ~~454964~~ 482505**	D1762		Note: No modification		
DRUM, V-1890, HYDROGEN PLT, H2S RECOVERY, H2 BOOSTER COMPR & PENTANE PLUS PLT RELIEF, WITH STEAM COIL, LENGTH: 21 FT; DIAMETER: 6 FT 6 IN **A/N: ~~454964~~ 482505**	D1763		Note: No modification		
KNOCK OUT POT, V-956, THERMAL DISTILLATION RECOVERY SYSTEM, LENGTH: 7 FT; DIAMETER: 2 FT **A/N: ~~454964~~ 482505**	D1764		Note: No modification		
VESSEL, SEPARATOR, DEGASSER, V-1175, HEIGHT: 19 FT; DIAMETER: 7 FT 1 IN **A/N: ~~454964~~ 482505**	D1767		Note: No modification		
KNOCK OUT POT, NHT NO. 3, V-1098, LENGTH: 20 FT; DIAMETER: 10 FT **A/N: ~~454964~~ 482505**	D2220		Note: No modification		E336.1
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~454964~~ 482505**	D3678		Note: No modification	HAP: (10) [40CFR 63 Subpart CC, #5A, 5-25-2001]	H23.3 (missing, added back)

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
DRUM, V-7317, FLARE KO T/T, HEIGHT: 10 FT; DIAMETER: 4 FT A/N 470739	D4341				K171.17
TANK, ANTI-FOAM AGENT CONTAIN POLYPROPYLENE GLYCOL, 1000 GAL, PART OF ANTI-FOAM INJECTION PACKAGE A/N 470739	D4342				K171.17

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 13: SULFUR PRODUCTION					P13.1
System 12: TAIL GAS TREATMENT UNIT NO. 73 - INCINERATOR					S7.4, S18.22
INCINERATOR, F-7304, TAIL GAS, NATURAL GAS (PRIMARY FUEL), 41.9 MMBTU/HR (HHV) BURNER, ULTRA LOW NOX, COEN/TODD COMBUSTION RMB (RAPID MIX BURNER) BOILER, WASTE HEAT (UNFIRED), A/N 480558	C4344	D4333 D4345	NOX: MAJOR SOURCE; SOX: MAJOR SOURCE	CO: 2000 PPMV (5) [RULE: 407,4-2-1982]; CO: 0.03 LB/MMBTU NAT GAS (4) [RULE 1303(a)(1)-BACT,5-10-96]; NOX: 0.02 LB/MMBTU NAT GAS (4) [RULE 2005,5-6-2005]; PM: 0.1 GRAINS/SCF (5) [RULE 409,8-7-1981]; PM: (9) [RULE 404,2-7-1986];	A63.28, A195.17, A195.18, C1.146, C8.19, D29.11 D82.11; D82.12; K171.17
BLOWER, K-7307 AND K-7307A (ONE SPARE), COMBUSTION AIR, ELECTRIC, 628 MSCFH, 100 HP A/N 480558	D4345				K171.17

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 13: SULFUR PRODUCTION					P13.1
System 13: TAIL GAS TREATMENT UNIT NO. 73 – SO_2 SCRUBBER (FINISHING)					S7.4
SCRUBBER, CAUSTIC, V-7324, SPRAY CHAMBER, COUNTER-CURRENT FLOW, HEIGHT 30 FT.; DIAMETER: 8 FT. A/N 498947	C4346	C4344			C8.20, C8.21, E129.1, K171.17

PROCESS CONDITIONS:

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

Contaminant	Rule	Rule/Subpart
Benzene	40CFR61, SUBPART	FF

[40CFR 61 Subpart FF, 12-4-2003][Processes subject to this condition: 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, **13**, 14, 16]

SYSTEM CONDITIONS:

S1.5 The operator shall limit the production rate to no more than 235 long ton(s) in any one day.

- The operator shall determine sulfur production on a daily basis.
- The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 2005, 5-6-2005] [Systems subject to this condition: Process 13, System 10]

S7.3 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-August-2006 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 1, System 5; Process 2, System 1 , 3 , 5 , 7; Process 10, System 1; Process 12, System 26 , 27; **Process 13, System 1 , 2 , 4; ~~Process 20, System 7~~** , 12]

[NOTE: There are no ongoing mitigation measures for this permit unit from the subject EIR.]

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 12, System 28**; **Process 13, System 10, 11, 12, 13**; Process 20, System 4, **7, 10**, 31

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
VESSEL, SEPARATOR, V-2502, PROCESS GAS, HEIGHT: 4 FT 7 IN; DIAMETER: 1 FT 8 IN **A/N: ~~454964~~ 482505**	D3028		Note: No modification		
FILTER, K-2502, PROCESS GAS, HEIGHT: 1 FT 2 25 IN; DIAMETER: 11. 5 IN **A/N: ~~454964~~ 482505**	D3029		Note: No modification		
KNOCK OUT POT, V-2500, LENGTH IS TANGENT TO TANGENT, WITH STEAM COIL, LENGTH: 25 FT; DIAMETER: 12 FT **A/N: ~~454964~~ 482505**	D3840		Note: No modification		

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 20: AIR POLLUTION CONTROL					
System 10: REFINERY BLOWDOWN GAS RECOVERY SYSTEM					S13.2, S15.5, S15.9, S18.12
KNOCK OUT POT, V-2010, RESID STRIPPER, LENGTH: 10 FT; DIAMETER: 7 FT 1 IN **A/N: ~~464817~~ 482504**	D1772		Note: No modification		
COMPRESSOR, ELECTRIC DRIVEN, K-2006, TWO-STAGE, RECIPROCATING, 4 MMSCFD **A/N: ~~464817~~ 482504**	D4211		Note: No modification		E73.8, L341.2
COMPRESSOR, ELECTRIC DRIVEN, K-2007, TWO-STAGE, RECIPROCATING, 4 MMSCFD **A/N: ~~464817~~ 482504**	D4212		Note: No modification		E73.8, L341.2
COMPRESSOR, ELECTRIC DRIVEN, K-2008, TWO-STAGE, RECIPROCATING, 4 MMSCFD **A/N: ~~464817~~ 482504**	D4213		Note: No modification		E73.8, L341.2
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~464817~~ 482504**	D3679			HAP: (10) [40CFR 63 Subpart CC, #5A,5-25-2001]	H23.19

CONDITIONS:

Additions are shown as underlined and deletions are shown as ~~strikeouts.~~

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**][Systems subject to this condition: **Process 13, System 1**]

S15.16 The vent gases from all affected devices of this process/system shall be vented as follows:

- All vent gases under normal operating conditions shall be directed to the Tail Gas Treatment Unit For Claus Unit No. 20 (Process 13, System 8).
- This process/system shall not be operated unless the tail gas treating unit is in full use and has a valid permit to receive vent gases from this system.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**][Systems subject to this condition: **Process 13, System 2**]

S15.17 The vent gases from all affected devices of this process/system shall be vented as follows:

- All vent gases under normal operating conditions shall be directed to the Tail Gas Treatment Unit For Claus Unit No. 70 (Process 13, System 9).
- This process/system shall not be operated unless the tail gas treating unit is in full use and has a valid permit to receive vent gases from this system.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**][Systems subject to this condition: **Process 13, System 4**]

S15.21 The vent gases from all affected devices of this process/system shall be vented as follows:

- All acid gases shall be directed to Claus Unit No. 73 (Process 13, System 10).
- This process/system shall not be operated unless the SRU is in full use and has a valid permit to receive vent gases from this system.

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**]

S15.22 The vent gases from all affected devices of this process/system shall be vented as follows:

- All tail gas under normal operating conditions shall be directed to the Tail Gas Treatment Unit No. 73 (Process 13, System 11).
- Vent gases may be directed to the Tail Gas Treatment Unit No. 73 Incinerator (Process 13, System 12) only during prescribed portions of a planned startup or planned shutdown.
- Acid gas shall not be fed to this process/system unless the Tail Gas Treatment Unit No. 73 is in full use and has a valid permit to receive vent gases from this system.
- This process/system shall not be operated unless the Incinerator is in full use and has a valid permit to receive vent gases from this system.

RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Systems subject to this condition: **Process 13, System 10**]

S13.2 All devices under this system are subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1123

[RULE 1123, 12-7-1990] [Systems subject to this condition : Process 1, System 3, 5, 13, 17; Process 2, System 1, 5, 6; Process 3, System 1 , 5; Process 4, System 1, 3, 5, 7, 9, 11, 13; Process 5, System 1; Process 6, System 1, 3, 4; Process 7, System 2, 4, 7; Process 8, System 1, 2, 5, 7, 8, 10; Process 9, System 1 , 2; Process 10, System 1 , 4; **Process 12, System** 2, 4, 7, 9, 10, 11, 12 , 13, 16, 17, 18, 22, 26, 27, **28**; **Process 20, System** 3, **4, 7, 10**, 11, 12, 14, 18, 19, 23; Process 21, System 13, 14, 16, 18]

S13.12 All devices under this system are subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
SOx	40CFR60, Subpart	Ja

This condition shall become effective upon startup of SRU No. 73 (Process 13, System 10)

[40CFR 60 Subpart Ja, 6-24-2008] [Systems subject to this condition : **Process 13, System 1, 2, 4, 10**]

S15.5 The vent gases from all affected devices of this process/system shall be vented as follows:

- All emergency vent gases from the vapor recovery system shall be directed to the flare system.
- This process/system shall not be operated unless the flare(s) is in full use and has a valid permit to receive vent gases from this system.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Systems subject to this condition : Process 2, System 5; Process 8, System 9; **Process 20, System 4, 10**, 28 , 29 , 30 , 34, 37]

S15.9 The vent gases from all affected devices of this process/system shall be vented as follows:

- All sour gases shall be directed to the sour gas treating unit(s).
- This process/system shall not be operated unless the sour gas treating unit(s) is in full use and has a valid permit to receive vent gases from this system.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Systems subject to this condition : Process 1, System 3 , 5 , 13; Process 2, System 1; Process 3, System 1; Process 4, System 1 , 3 , 7 , 9 , 11 , 13; Process 7, System 4; Process 8, System 1; Process 10, System 1; Process 12, System 7; **Process 20, System 4, 10**, 28 , 29 , 30]

S15.15 The vent gases from all affected devices of this process/system shall be vented as follows:

- All vent gases under normal operating conditions shall be directed to the Tail Gas Treatment Unit For Claus Unit No. 10 (Process 13, System 7).
- This process/system shall not be operated unless the tail gas treating unit is in full use and has a valid permit to receive vent gases from this system.

- Miscellaneous (Process: 21, System: 13 & 18)

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Systems subject to this condition: **Process 20, System** 3, 7, 23]

S18.12 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:

- Crude Distillation (Process: 1, System: 3, 5 & 13)
- Coking & Residual Conditioning (Process: 2, System: 1)
- Hydrotreating (Process: 4, System: 1, 9, 11 & 13)
- Hydrogen Generation (Process: 6, System: 4)
- Alkylation (Process: 8, System: 2 & 5)
- Coker Depropanizer (Process: 10, System: 1)
- Treating and Stripping (Process: 12, System: 26, 27, **28**)
- **Sulfur Production (Process 13, System 10, 11)**
- Vapor Gathering System (Process: 20, System: 18)

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Systems subject to this condition: Process 2, System 5; **Process 20, System 10]**

S18.20 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:

- Treating & Stripping (Process: 12, System: 12, 13, 23, 24, 25, 27 and 28)
- Tail Gas Treatment Unit No 73 (Process: 13, System: 11)

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Systems subject to this condition: **Process 13, System 10]**

S18.21 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:

- Sulfur Recovery – Claus Unit No. 73 (Process 13, System 10)

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Systems subject to this condition: **Process 13, System 11]**

S18.22 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:

- Sulfur Recovery Unit No. 73 (Process 13, System 10)
- Tail Gas Treatment Unit No. 73 (Process 13, System 11)

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Systems subject to this condition: **Process 13, System 12]**

S31.20 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 466150, 466876, **467141**, 467544, ~~and~~ 467547 and **470739**:

S56.1 Vent gases from all affected devices of this process/system shall be directed to a gas recovery system, except for venting from those devices specifically indicated in a permit condition, and for the following vent gases which may be directed to a flare:

1) Vent gases during an emergency. For the purpose of this condition, emergency is defined in accordance Rule 1118(b)(2).

2) Vent gases during startups, shutdowns or turnarounds as defined in Rule 1118 provided that all flares have been operated in accordance with flaring minimization procedures as described in Rule 1118(c)(3); and

3) Vent gas due to essential operating needs, as defined in Rule 1118(b)(4)(A) that would result in a temporary fuel gas system imbalance, or as defined in Rule 1118(b)(4)(C) that would result in streams that cannot be recovered due to incompatibility with recovery system equipment or with refinery fuel gas systems, provided that all flares have been operated in accordance with flaring minimization procedures as described in Rule 1118(c)(3).

The flaring minimization procedures and any subsequent changes shall be submitted to the District as described in Rule 1118(c)(3).

This process/system shall not be operated unless its designated vapor recovery system and flare are in full use and have valid permits to receive vent gases from this system.

[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 10, 11]**

S18.1 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:
- Treating & Stripping (Process: 12, System: 12, 13, 23, 24, 25, & 27)
- Tail Gas Plants (Process: 13, System: 5 & 6)

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996][Systems subject to this condition: **Process 13, System 1, 2, 4**]

S18.7 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:
- Crude Distillation (Process: 1, System: 3, 5 & 13)
- Delayed Coking (Process: 2, System: 1 & 5)
- FCCU (Process: 3, System: 1 & 5)
- Hydrotreating (Process: 4, System: 1, 7, 9, 11 & 13)
- Hydrogen Generation (Process: 6, System: 4)
- Alkylation (Process: 8, System: 1, 2, 5, 7, 8, 9 & 10)
- Oxygenates Production (Process: 9, System: 2)
- LPG Production (Process: 10, System: 1 & 2)
- Treating & Stripping (Process: 12, System: 2, 7, 9, 11, 13, 17, 22, 23, 25, 26, 27 & **28**)
- **Sulfur Production (Process 13, System 10, 11)**
- Air Pollution Control (**Process: 20, System: 10** & 34)

DEVICE CONDITIONS

A63.28 The operator shall limit emissions from this equipment as follows:

- VOC - Less than or equal to 7.0 LBS IN ANY ONE DAY
- PM10 - Less than or equal to 7.5 LBS IN ANY ONE DAY

The operator shall calculate the emission limit(s) for compliance determination purposes for VOC and PM10 based on at least three one-hour source tests using District-approved test methods for emission rates and natural gas usage as determined by a RECLAIM or Rule 218 certified fuel meter during the day of the test (0000 - 2400 hours).

[RULE 1303(b)(2)-Offset, 5-10-1996] [Devices subject to this condition: **C4344**]

A195.15 The 12 PPM SO2 emission limit is averaged over 72 hours at 0% O2, dry basis.

[RULE 2005, 5-6-2005] [Devices subject to this condition: **D4321**]

A195.16 The 2.5 ppmv H2S emission limit is averaged over 24 hours at 0% O2, dry basis.

[RULE 2005, 5-6-2005] [Devices subject to this condition: **D4321**]

A195.17 The 0.02 lb/MMBtu NOx limit, which is based on the lower heating value (LHV) of the natural gas combusted in the incinerator, is averaged over 24 hours.

[RULE 2005, 5-6-2005] [Devices subject to this condition: **4344**]

A195.18 The 0.03 lb/MMBtu CO limit, which is based on the lower heating value (LHV) of the natural gas combusted in the incinerator, is averaged over 24 hours.

[RULE 1303(a)(1)-BACT, 5-10-1996] [Devices subject to this condition: D4344]

B61.11 The operator shall not use / combust vent gas containing the following specified compounds:

- H2S greater than 160 ppm by volume
- The H2S concentration limit shall be based on a rolling 3-hour averaging period.
- The H2S concentration limit shall not apply to vent gas resulting from an emergency, shutdown, startup, process upset or relief valve leakage.

[Rule 1118, 11-4-2005]][Devices subject to this condition: C1746, C1749, **C1757**, C1785, C3012, C4116]

C1.146 The operator shall limit the firing rate to no more than 41.9 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 value (HHV) of the natural gas used.
- To comply with this condition, the operator shall install and maintain a(n) continuous monitoring system to accurately indicate the energy input being supplied to the heater.
- The operator shall also install and maintain a device to continuously record the parameter being measured.

[RULE 1303(b)(2)-Offset, 5-10-1996][Devices subject to this condition : **D4344**]

- 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: <u>**Process 12, System 28**</u>; <u>**Process 13, System 11**</u>; Process 16, System 10; Process 20, System 37]

Formaldehyde		averaging time	
Benzene, Toluene, Ethyl benzene, and xylene	Approved District Method	District-approved averaging time	Outlet of Scrubber
COS, CS2, and H2S	Approved District Method	District-approved averaging time	Outlet of Scrubber
NH3	Approved District Method	District-approved averaging time	Outlet of Scrubber

- The test shall be conducted when this equipment is operating at 80 percent or greater of the maximum design capacity. If the equipment is not capable of operating at this required load, then the source test may be conducted at a lower load and the operation of the equipment limited to 115% of the level at which the source test was conducted until an additional source test is conducted at a higher operating rate.
- 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, COS, CS2, H2S, and NH3.
- 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.
- The test(s) shall be conducted at least annually after the initial source test for NOx, SOx, CO, O2, COS, CS2, H2S, and NH3.
- The test(s) shall be conducted at least every three years after the initial source test for ROG, PM10, and total PM 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 : **D4344**]

D12.14 The operator shall install and maintain a(n) thermocouple or any other equivalent device to accurately indicate the presence of a flame at the pilot light.

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

[RULE 1303(a)(1)-BACT, 5-10-1996; 40CFR 60 Subpart A, 4-9-1993; 40CFR 63 Subpart A, 3-16-1994] [Devices subject to this condition: C1746, C1749, **C1757**, C1785, C3012]

D82.11 The operator shall install and maintain a CEMS to measure the following parameters:

- CO concentration in ppmv
- Oxygen concentration in percent volume
- The CEMS shall be approved, operated and maintained in accordance with the requirements of Rule 218.

C8.19 The operator shall use this equipment in such a manner that the temperature being monitored, as indicated below, is not less than 1450 Deg F.

- The temperature limit is average over 15 minutes.
- To comply with this condition, the operator shall install and maintain a(n) temperature reading device to accurately indicate the temperature in the thermal oxidation chamber
- The operator shall also install and maintain a device to continuously record the parameter being measured.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(a)(1)-BACT, 5-10-1996] [Devices subject to this condition:**C4344**]

C8.20 The operator shall use this equipment in such a manner that the flow rate being monitored, as indicated below, is not less than 1900 gpm.

- The flow limit is average over 15 minutes.
- To comply with this condition, the operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the recirculating caustic solution.
- The operator shall also install and maintain a device to continuously record the parameter being measured.
- The continuous monitoring system shall include visual and audio alarms.
- 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: **C4346**]

C8.21 The operator shall use this equipment in such a manner that the pH being monitored, as indicated below, is not less than 6.5 of the pH scale.

- The pH limit is average over 15 minutes.
- To comply with this condition, the operator shall install and maintain a pH meter to accurately indicate the pH of the recirculating caustic solution.
- The operator shall also install and maintain a device to continuously record the parameter being measured.
- 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: **C4346**]

D29.11 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	Outlet of Scrubber
SOx emissions	District Method 100.1 or 6.1	1 hour	Outlet of Scrubber
CO emissions	District Method 100.1 or 10.1	1 hour	Outlet of Scrubber
ROG emissions	District Method 25.1 or 25.3	1 hour	Outlet of Scrubber
PM emissions	Approved District Method	District-approved averaging time	Outlet of Scrubber
PM10 emissions	Approved District Method	District-approved averaging time	Outlet of Scrubber
Acetaldehyde and	Approved District Method	District-approved	Outlet of Scrubber

E71.27 The operator shall not use this equipment when all of the blowers K-101, K-102, K-201 and K-202 are operating simultaneously together. This equipment shall only be used as a spare unit.

[RULE 1303(b)(2)-Offset, 5-10-1996][Devices subject to this condition: **D3835**]

E71.28 The operator shall not use this equipment when all of the blowers K-701 and K-751 are operating simultaneously together. This equipment shall only be used as a spare unit.

[RULE 1303(b)(2)-Offset, 5-10-1996][Devices subject to this condition: **D3836**]

E73.8 Notwithstanding the requirements of Section E conditions, the operator is not required to use all three Refinery Blowdown Gas Recovery System compressors concurrently if: The load on the Refinery Blowdown Gas Recovery System is not sufficient to require all compressors to be online.

[RULE 1303(a)(1)-BACT, 5-10-1996] [Devices subject to this condition: **D4211, D4212, D4213**]

E129.x1 The operator shall only dispose spent caustic from this equipment to a spent caustic treatment system or an acceptable treatment or disposal site.
[RULE 2005, 4-20-2001] [Devices subject to this condition : C4346]

E336.1 The operator shall vent the vent gases from this equipment as follows:

- All vent gases under normal operating conditions shall be directed to the coker blowdown system (Process 2, System 5) or/and refinery blowdown system (Process 20, System 10).
- This equipment shall not be operated unless the above blowdown system(s) is in full use and has a valid permit to receive vent gases from this equipment.

[RULE 1303(a)(1)-BACT, 5-10-1996] [Devices subject to this condition: **D2220**]

E336.15 The vent gases from all affected devices of this process/system shall be vented as follows:

- All vent gases under normal operating conditions shall be directed to the Tail Gas Treatment Unit No. 73 Incinerator (Process 13, System 12)
- This process/system shall not be operated unless the TGTU Incinerator is in full use and has a valid permit to receive vent gases from this system.

RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996] [Devices subject to this condition: **D4333**]

H23.3 This equipment is subject to the applicable requirements of the following rules or regulations: VOC – District Rule 1173

[RULE 1173, 5-13-1994; RULE 1173, 2-6-2009][Devices subject to this condition : D3576, D3577, D3581, D3584, D3586, D3588, D3595, D3610, D3631, D3635, D3640, D3642, D3643, D3644, D3645, D3646, D3649, D3650, D3651, **D3654**, D3655, D3656, D3657, D3659, D3660, D3661, D3662, D3663, D3664, D3665, D3666, D3667, D3668, D3669, D3670, **D3678**, D3679, D3680, D3681, D3682, D3684, D3685, D3691, D3692, D3693, D3694, D3760, D3802, D3866, D4086, D4087, D4088, **Dxxx5**]

- The CEMS shall convert the CO concentrations to mass emission rates (lbs/mmbtu of natural gas combusted) on a continuous basis. The natural gas firing rate shall be determined by a RECLAIM or Rule 218 certified fuel meter and the low heating value (LHV) of the natural gas.

[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: **D4344**]

D82.12 The operator shall install and maintain a CEMS to measure the following parameters:

- NOx concentration in ppmv
- SOx concentration in ppmv
- Oxygen concentration in percent volume
- The CEMS shall convert the NOx concentrations to mass emission rates (lbs/mmbtu of natural gas combusted) on a continuous basis. The natural gas firing rate shall be determined by a RECLAIM or Rule 218 certified fuel meter and the low heating value (LHV) of the natural gas.

[RULE 2005, 5-6-2005] [Devices subject to this condition: **D4344**]

D323.2 The operator shall conduct an inspection for visible emissions from all stacks and other emission points of this equipment whenever there is a public complaint of visible emissions, whenever visible emissions are observed, and on an semi-annual basis, at least, unless the equipment did not operate during the entire semi-annual period. The routine semi-annual inspection shall be conducted while the equipment is in operation and during daylight hours.

If any visible emissions (not including condensed water vapor) are detected that last more than three minutes in any one hour, the operator shall verify and certify within 24 hours that the equipment causing the emission and any associated air pollution control equipment are operating normally according to their design and standard procedures and under the same conditions under which compliance was achieved in the past, and either:

1). Take corrective action(s) that eliminates the visible emissions within 24 hours and report the visible emissions as a potential deviation in accordance with the reporting requirements in Section K of this permit; or
2). Have a CARB-certified smoke reader determine compliance with the opacity standard, using EPA Method 9 or the procedures in the CARB manual "Visible Emission Evaluation", within three business days and report any deviations to AQMD.

The operator shall keep the records in accordance with the recordkeeping requirements in Section K of this permit and the following records:
1). Stack or emission point identification;
2). Description of any corrective actions taken to abate visible emissions;
3). Date and time visible emission was abated; and
4). All visible emission observation records by operator or a certified smoke reader.

[RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 401, 3-2-1984] [Devices subject to this condition : C1746, C1749, **C1757**, C1785, C3012]

FEE ANALYSIS

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

Table 1 – Summary of Fee Analysis

A/N	Equipment Description	BCAT/ CCAT	Fee Schedule	Fee Type	Fiscal Year (1)	Fee
467141	Sour Water Stripper	95 (CCAT)	D	New Construction	06-07	$ 3,701.25
470738	Sulfur Recovery Plant	289620 (BCAT)	H	New Construction	06-07	$ 18,640.52
470739	Tail Gas Unit	91 (CCAT)	H	New Construction	06-07	$ 18,640.52
480558	Tail Gas Incinerator	96 (CCAT)	D	New Construction	07-08	$ 4,071.37
482504	Refinery Blowdown Gas Recovery System	59 (CCAT)	E	Modification	07-08	$ 4,680.85
482505	LSFO Emergency Relief System (Flare)	92 (CCAT)	F	Modification	07-08	$ 9,325.11
498947	SOx Scrubber	4B (CCAT)	D	New Construction	08-09	$ 4,478.51
499500	Sulfur Recovery Plant	289620 (BCAT)	H	Change of Condition	08-09	$ 13,873.64
499877	Sulfur Recovery Plant	289620 (BCAT)	H	Change of Cond. (Identical Equip.)	08-09	$ 6,936.82
499878	Sulfur Recovery Plant	289620 (BCAT)	H	Change of Cond. (Identical Equip.)	08-09	$ 6,936.82
??????	RECLAIM/Title V Permit	555009 (BCAT)	C	Facility Permit Amendment	09-10	$ 1,687.63
				Total		**$ 92,973.04**
				Fees Paid		**$ 92,973.04**
				Outstanding Balance		**$ 0.00**

(1) Based on the date that the application was submitted.

PERMIT HISTORY

Since the SWS, SRU, TGTU, TGTU Incinerator and SOx Scrubber are proposed for new construction, there are no previous permits for these sources. The permit histories for the existing SRUs, Refinery Blowdown Gas Recovery System and LSFO Flare are contained in the following tables.

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

- VOC – District Rule 1173
- VOC – 40 CFR 60, Subpart GGG

[**RULE 1173, 5-13-1994**; RULE 1173, 2-6-2009; **40CFR 60 Subpart GGG, 6-7-1985**] [Devices subject to this condition : D3577, D3579, D3580, D3581, D3583, D3587, D3613, D3622, D3634, D3636, D3637, D3638, D3639, D3675, D3676, **D3679**, D3686, D3803, D3921, D3969, D4085, D4107, D4208]

H23.44 This equipment is subject to the applicable requirements of the following rules or regulations:

- H2S - 40 CFR 60, Subpart J

[**40CFR 60 Subpart J, 6-24-2008; CONSENT DECREE CIVIL NO. C 03-04650 CRB, 6-27-2005**][Devices subject to this condition: D20, D453, D502, D504, C1746, **C1757**, C2158, C3012, C3493]

H23.46 This equipment is subject to the applicable requirements of the following rules or regulations:

- SOX - District Rule 1118

[**RULE 1118, 11-4-2005**][Devices subject to this condition : C1746, C1749, **C1757**, C1785, C3012, C4116]

K171.17 The operator shall provide to the District the following items:
Final drawings and/or specifications of the equipment installed/constructed/modified, including but not limited to PFD, P&ID and revisions/updates, shall be submitted to the SCAQMD within 60 days after completion of the project.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**] [Devices subject to this condition: D471, D472, D473, D1929, D1930, C1967, D3031, D3342, D3631, D3955, **D4305 – D4335, C4336, D4337-D4343, C4344, D4345, D4346]**

L341.2 Within one year after start-up of this equipment, the following device(s) shall be removed from operation:

- Compressor K-2002 identified by Device No. D1782
- Compressor K-2003 identified by Device No. D1783
- Compressor K-2004 identified by Device No. D1784

Startup as used in this condition shall mean initial use or operation of the equipment after its installation.
During the start-up period, the old compressors (D1782, D1783 & D1784) and the new compressors (D4211, D4212 & D4213) shall not be operated simultaneously for a cumulative total of more than 90 days. Records shall be kept to show compliance with this condition.

[**RULE 1303(b)(2)-Offset, 5-10-1996**] [Devices subject to this condition: **D4211, D4212, D4213**]

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
				(F-107; D929). Minimal increase in fugitive ROG emissions of 0.08 lb/day).
385235	na.	F61185	6/3/03	Admin. Application. Add existing atmospheric PRDs to equipment descriptions.
400458	12/27/02	na.	na.	Installation of a spare blower that is common to SRUs no. 10 and 20.
445740	na.	na.	na.	Change of condition appl. to incorporate NSPS Subpart J emission limits and requirements into the SRU permit as required by a consent decree with US DOJ and US EPA. This application was cancelled and NSPS Subpart J requirements evaluated under AN 454962.
454962	na.	na.	na.	Connection of the new No. 6 H2S Plant DEA Regenerator.
499877	na.	na.	na.	Chevron's Sulfur Recovery Plant, which is currently composed of SRU Nos. 10, 20 & 30, became subject to NSPS Subpart Ja because construction of SRU No. 73 is a modification of the Sulfur Recovery Plant.

Permit History for Sulfur Recovery – Claus Unit No. 70 (P13S3)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
A75855	6/13/73	na.	na.	Original construction of this 300 long ton per day Sulfur Recovery Plant as part of the Low Sulfur Fuel Oil (LSFO) Project. Chevron submitted a new application of construction of this plant because construction was started but not completed prior to the expiration of this permit to construct.
A87738	6/25/75	M04745		New permit to construct was issued for construction of this plant since construction was not completed under PC AN A75855.
226489	na.	D33697	11/06/90	Installation of a filter and liquid K.O. pot of the fuel gas line to the Tail Gas Oxidizer (F-750; D955) and Stack Gas Heater (F-790; D957). Increase of 1 lb/day of fugitive ROG emissions.
257878	2/10/92	D90526	5/28/95	Added three HXs, a K.O pot, and a pump to supply ammonia to the SRU to be disassociated to nitrogen and water vapor. The liquid ammonia, which was produced at the Isomax, was previously shipped offsite via tank truck.
385211	na.	F44549	10/04/01	Install piping to allow the use of natural gas as a secondary fuel in the Tail Gas Oxidizer (F-750; D955) and Stack Gas Heater (F-790; D957). Minimal increase in fugitive ROG emissions of 0.08 lb/day).
385219	na.	F61186	6/3/03	Administrative application. Add existing atmospheric PRDs to equipment descriptions.
400556	na.	F61184	2/25/03	Installation of a spare blower that is common to SRUs no. 10 and 20.

Permit History for Sulfur Recovery – Claus Unit No. 10 (P13S1)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
A64573	12/13/71	P53416	6/29/73	Original construction.
257877	2/10/92	D99441	5/28/95	Added three HXs, a K.O pot, and a pump to supply ammonia to the SRU to be disassociated to nitrogen and water vapor. The liquid ammonia, which was produced at the Isomax, was previously shipped offsite via tank truck.
337298	5/14/98	na.	na.	Installation of an oxygen enrichment system. Increased capacity from 150 long tons per day (ltpd) up to 187.5 ltpd as well as other benefits. No increase in emissions according to evaluation.
385212	na.	F44550	10/04/01	Install piping to allow the use of natural gas as a secondary fuel in the Tail Gas Oxidizer (F-105; D911) and Stack Gas Heater (F-107; D913). Minimal increase in fugitive ROG emissions of 0.08 lb/day).
385234	na.	F61187	6/3/03	Admin Application. Add existing atmospheric PRDs to equipment descriptions.
400457	12/27/02	na.	na.	Installation of a spare blower that is common to SRUs no. 10 and 20.
445739	na.	na.	na.	Change of condition appl. to incorporate NSPS Subpart J emission limits and requirements into the SRU permit as required by a consent decree with US DOJ and US EPA. This application was cancelled and NSPS Subpart J requirements evaluated under AN 449360.
449360	na.	na.	na.	Connection of the new No. 6 H2S Plant DEA Regenerator.
499500	na.	na.	na.	Chevron's Sulfur Recovery Plant, which is currently composed of SRU Nos. 10, 20 & 30, became subject to NSPS Subpart Ja because construction of SRU No. 73 is a modification of the Sulfur Recovery Plant.

Permit History for Sulfur Recovery – Claus Unit No. 20 (P13S2)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
A64572	12/13/71	P53415	6/29/73	Original construction.
257876	2/10/92	D90525	5/28/95	Added three HXs, a K.O pot, and a pump to supply ammonia to the SRU to be disassociated to nitrogen and water vapor. The liquid ammonia, which was produced at the Isomax, was previously shipped offsite via tank truck.
337299	5/14/98	na.	na.	Installation of an oxygen enrichment system. Increased capacity from 150 long tons per day (ltpd) up to 187.5 ltpd as well as other benefits. No increase in emissions according to evaluation.
385210	na.	F44548	10/04/01	Install piping to allow the use of natural gas as a secondary fuel in the Tail Gas Oxidizer (F-205; D927) and Stack Gas Heater

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
406045	02/18/03	na.	na.	Administrative application. PC AN 336106, permitted the removal of the ground flare but it was not removed from the permit until the flare was removed from service. Since a PO had not been issued with the ground flare removed. Chevron requested the removal. Also included existing K.O pot V-2500 in the permit.
419472	11/04/03	na.	na.	Connection of emergency PRDs in the new No. 6 H2S Recovery Plant (P12S26).
434803	na.	na.	na.	Change of condition application related to the flame monitoring condition (D12.14). Consolidated with AN 454964 for evaluation.
454964	8/09/06	na.	na.	Heavy Crude Project: Connection of emergency PRDs in the new No. 6 H2S Plant Amine Regeneration Unit (P12S27).
482505	na.	na.	na.	PRO Project: Connection of emergency PRDs in the new Sour Water Stripper (P12S28), SRU No. 73 (P13S10), and TGTU No. 73 (P13S11).

Permit History for the Refinery Blowdown Gas Recovery (P20S10)
[Ref.: AN464817, etc, Eng'g Evaluation dated 7/05/07 by E. Ruivivar]

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
9152	4-8-54			Modification to connect additional vent streams. Note: No records found when original P/O was issued.
A5252, A16700, A5666, A8601, A12519, A51775	-- -- 4-14-59 -- -- --	-- -- -- 16426 -- --		Modifications to connect additional vent streams.
A68367	--	P-49866		Modification by replacement of 1st stage cylinder of K-202 compressor and the addition of a condensate drum & PRV connection to the FCCU flare.
A75078	--	P-54448		Modification by addition of service to No. 3 caustic treating plant and to a waste gas compressor station or additional vent streams.
C-12975	--	M03864	4-18-78	Minor modification to include listing of fuel gas K.O. drum and filter in the permit, and also the alteration of the numbering to the system.
C20468		M24849	5/12/82	Modification by the replacement of pump P-2010 and removal of compressor K-20.
421284	na.	F70108	8/04/04	Modification of Condition S18.12 to allow this vapor recovery system to receive vent gases from the new No. 6 H2S Recovery Plant (Process 12, System 26).
464817	na.	na.	na.	Replacement of the three Houdry Compressors @ 2 MMSCFD

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
445741	na.	na.	na.	Incorporated NSPS Subpart J emission limits and requirements into the SRU permit as required by a consent decree with US DOJ and US EPA. This application was cancelled and NSPS Subpart J requirements evaluated under AN 454963.
454963	na.	na.	na.	Connection of the new No. 6 H2S Plant DEA Regenerator.
499878	na.	na.	na.	Chevron's Sulfur Recovery Plant, which is currently composed of SRU Nos. 10, 20 & 30, became subject to NSPS Subpart Ja because construction of SRU No. 73 is a modification of the Sulfur Recovery Plant.

Permit History for LSFO Emergency Relief System (P20S7)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
A75857	01/73	M00754	7/21/77	Original construction of this emergency relief system(ERS) consisting of a ground flare as a primary flare with an elevated flare to handle relief loads that were greater than the 50,000 lb/hr capacity of the ground flare. The ERS was constructed to handle process upsets in the following process units: Crude Unit No. 4, Naptha Hydrotreater No. 12, Steam Naptha Reformer, Isomax VRDS, Isomax VGO, H2S Recovery Plant No. 5, and the pentanes plus plant.
160485		D05666	2/8/89	Connection of the emergency PRDs in the Copex Plant, Caustic Treating Plant No. 3, and the vapor recovery compressors (K-1 through K-5) to the LSFO ERS.
212958		D33226	10/25/90	Connection of the Thermal Distillation Recovery System (TDRS) to the LSFO ERS through a K.O drum. Appears that this TRDS was either never constructed or has been taken out of service.
235938	1/01/91	na.	na.	Chevron modified the Alky Units Vapor Recovery System. Previously, relief gases were discharged to two gas holders (T-2010 and T-20202) that were upstream of some Houdry Compressors. If the compressors were unavailable or overloaded, the tanks were vented to the atmosphere. Under this modification, the gas holders were removed and the Alky VRS was tied into the LSFO and FCCU ERSs. Included installation of associated K.O pots and pumps.
301080	4/27/95	na.	na.	Connection of emergency PRDs in the Penex Isomerization Plant (P8S5) and Naptha Hydrotreater No. 3 (P4S13) as part of Chevron's RFG II project. Also removed the connection for the old Alkylation Plant (P4S2), which was removed from service. Include installation of a separator vessel and filter to minimize scaling in the spark arrestor.
336106	2/06/98	na.	na.	Removed the ground flare from operation.

PROCESS DESCRIPTION:

Sour Water Stripper (Process 12, System 28) (AN 466149)

Overview: Sour water streams containing ammonia (NH_3), hydrogen sulfide (H_2S), and liquid hydrocarbons, are collected from various process units in the refinery. This sour water is collected in one of the following existing storage tanks:

- Tank 121 (D1346) - 24,000 barrels
- Tank 130 (D1347) - 24,000 barrels
- Tank 451 (D1378) - 47,562 barrels
- Tank 453 (D1379) - 59,750 barrels
- Tank 454 (D1380) - 57,313 barrels
- Tank 458 (D1381) - 59,300 barrels
- Tank 499 (D1394) - 128,830 barrels
- Tank 9453 (D1457) - 78,400 barrels
- Tank 9459 (D1460) - 112,000 barrels

Eight (8) of these tanks are domed external floating roof tanks. Tank 9459 is the only tank that is not equipped with a dome. Depending on need, these tanks may also store other intermediate products or waste streams. Sour water from these tanks is currently sent to one of the following Sour Water Strippers (SWS) for removal of the NH3 and H2S:

- NH3-H2S Recovery Sour Water Stripper (Process 12, System 12)
- NH3-H2S Concentrator/Stripper (Process 12, System 13)

The proposed new SWS will also treat sour water sent from the sour water tanks listed above. The capacity of the new SWS is approximately 330 gpm (11,300 bbl/day).

New Sour Water Stripper: As seen on the process flow diagram in Appendix C, sour water from the sour water storage tanks flows through two parallel sour water prefilters (K-6801 & K-6801A) and the oil separator (V-6801). Slop oil recovered in the oil separator is pumped to the slop oil system. The sour water is them preheated by the SWS bottoms stream in parallel heater exchangers (E-6815 & E-6815A) prior to being pumped to the top of the stripper column (C-6810). A steam heated reboiler is utilized to generate hot vapors that flow up the stripper column to strip H2S and NH3 from the downcoming sour water. The H2S/NH3 rich overhead vapors are sent through an overhead condenser (E-6810) and accumulator (V-6820). The condensed liquid from the accumulator is pumped back to the top of the stripper column to provide internal reflux. The vapor stream from the accumulator will be sent to the proposed new SRU/TGTU via the V-7302 knockout drum in the SRU. Note that a 20 Degree Baume' caustic is injected near the bottom of the stripper column to neutralize any organic acids contained in the sour water from the FCCU and Delayed Coking Unit.

The majority of the stripped water from the stripper column flows through the feed/bottoms heat exchanger (E-6815/A) back to refinery processing units. Any stripped water not recycled to refinery processing units is further cooled in the Bottoms Cooler (E-6820) before flowing to the refinery's segregated drainage system. The equipment list for the new SWS is contained in the table below.

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
				with three new larger compressors at 4 MMSCFD each..
482504	na.	na.	na.	PRO Project: Connection of PRDs in the new Sour Water Stripper (P12S28), SRU No. 73 (P13S10) and TGTU No. 73 (P13S11).

COMPLIANCE RECORD REVIEW

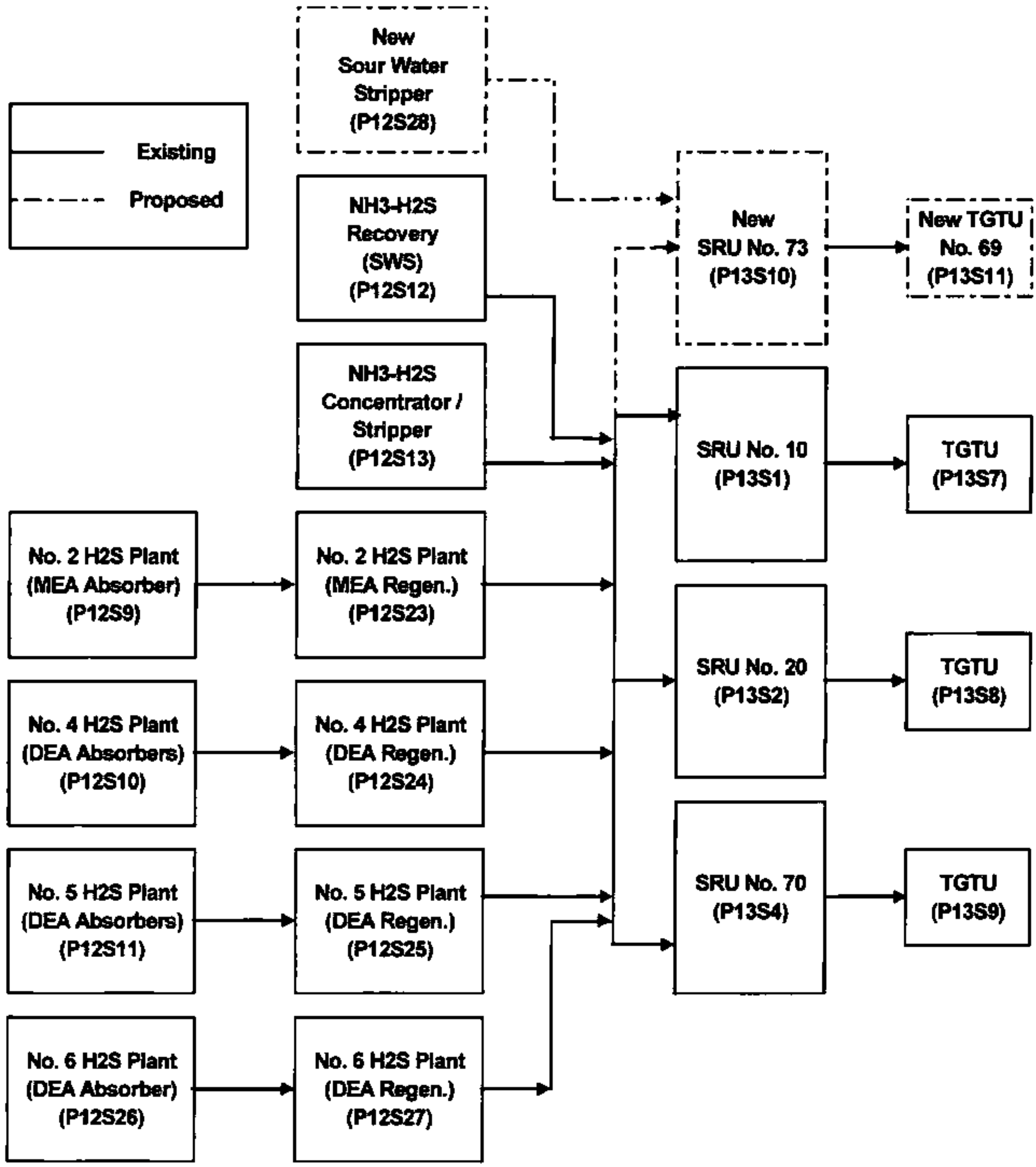
Appendix B lists the NCs and NOVs issued to Chevron since January 1, 2006. There are no ongoing violations for any of the equipment affected by this project.

The LSFO Flare is included in a variance under Hearing Board Case No. 8313-43. This variance covers certain monitoring requirements of District Rule 1118, which was amended in November of 2005. Subsection (g)(3) of the amended rule specifies that owners or operators with flares subject to the rule shall install and operate a flare monitoring system (FMS) by July 1, 2007 to perform monitoring and recording of the parameters specified in the second section of Table 1 of the rule. This monitoring includes gas flow, gas higher heating value (HHV), and total sulfur concentration (TSC) of the gas. Subsections (g)(3) and (j)(1)(C) contain performance specifications for the monitors. Rule 1118(j)(1)(C) also requires that the accuracy of the flow meter be verified annually according to manufacturer specifications. Additionally, Rule 1118 contains reporting requirements that are based on these monitoring requirements.

At the time of the rule adoption in 2005, technical challenges and issues related to feasibility, reliability, maintainability, accuracy, and safety of the HHV and TSC analyzers had the potential to delay implementation of the specified monitoring systems. Due to these known issues, the AQMD Governing Board adopted a resolution directing AQMD staff to work with the Western States Petroleum Association and its refiner members to resolve outstanding issues. Due to the analyzer related delays, each of the refineries requested and was granted a variance to the requirement to continuously monitoring TSC and HHV by July 1, 2007. The variances gave the refineries until September 1, 2008, to complete the design, acquisition, and installation of the required analyzers

Pilot projects for the development of TSC and HHV analyzers were completed in March 2008. Based on a determination that the pilot analyzers demonstrated compliance with the technical requirements of Rule 1118, the AQMD approved the tested TSC and HHV analyzers on May 20, 2008. Since the analyzer approval was given later than expected, the refineries petitioned for a modification and extension of the variance. The Hearing Board granted an extension of Chevron's variance (Case No. 8313-43) until June 24, 2010. Under the increments of progress for the variance, Chevron must install and test the TSC and HHV analyzers on the LSFO Flare by February 4, 2010.

Condition I1.1 has been added to the affected equipment in section D and H of the permit requiring the operator to comply with all the conditions of the variance including the submittal of progress reports.



Overview of Chevron El Segundo Refinery Sulfur Treating Systems

Proposed Equipment in the New Sour Water Stripper (Process 12, System 28)

Equipment	Tag No	Device No.	Dimensions/Rating
Construction Of:			
• Sour Water Stripper	C-6810	Dxxx3	Ht.: 122-ft.; Dia.: 5-ft 0-in
• Oil Separator	V-6801	Dxxx2	Length: 10-ft; Dia.: 3-ft
• Overhead Accumulator	V-6820	Dxxx4	Length: 10ft; Dia.:3-ft 6-in
• Overhead Condenser	E-6810	na.	16.8 MMBTU/Hr. Area/Shell 970 ft^2
• Feed/Bottoms Exchanger	E-6815/A	na.	15.3 MMBTU/Hr. (total for both); Area/Shell 10,000 ft^2
• Bottoms Cooler	E-6820	na.	13.0 MMBTU/Hr.; Area/Shell 1670 ft^2
• Feed Pump	P-6805/A	na.	Flow Rate: 330 gpm; 51 HP, electric (one spare)
• Reflux Pump	P-6810/A	na.	Flow Rate: 41 gpm; 3.1HP, electric (one spare)
• Bottoms Pump	P-6815/A	na.	Flow Rate: 433 gpm; 31 HP, electric (one spare)
• APS Injection Package	PK-6801	na	Tank: 500 gal capacity; Pumps (Two Pumps, One Spare, electric) Flow rate: 1.8 gph
• Sour Water Prefilters	K-6801/A	Dxxx1	Length: 8-ft 6-in; Dia.: 3-ft (filters in parallel)

Note: Lengths and heights are measured from tangent to tangent

Sulfur Recovery Unit No 73, Tail Gas Treatment Unit No. 73, and TGTU Incinerator (Process 13, Systems 10-12)

Overview of Sulfur Treating Systems

Off-gas streams from various refinery processes, including the coker, catalytic cracking unit, hydrotreating units, and hydroprocessing units, are combusted in process heaters in the refinery. These off-gas streams are often referred to as sour gas streams since they can contain high concentrations of H2S and lower concentrations of other reduced sulfur species such as mercaptans and carbonyl sulfide (COS). To reduce SO2 emissions from the combustion of these sour gas streams and to recover saleable elemental sulfur, the majority of the reduced sulfur compounds are removed from the sour gas in the four H2S plants located at the Chevron El Segundo Refinery.

In the H2S plants, the H2S is removed from these sour gas streams by dissolving it in a chemical solvent. The most commonly used solvents for H2S are amines, such as diethanolamine (DEA) and monoethaonolamine (MEA). In the amine solvent processes, DEA or MEA solution is pumped to an absorption tower where the sour gases are contacted and hydrogen sulfide is dissolved in the solution. The gas stream from the absorption tower flow to one of the fuel mix drums for use as fuel in process heaters at the refinery operations. The amine / hydrogen sulfide solution is regenerated through heating and steam stripping the H2S from the amine solution. The stripped H2S stream, which is often referred to as acid gas, is sent to the Sulfur Recovery Units (SRU) / Tail Gas Treatment Units (TGTUs) where 99.9+ percent of the H2S is converted to elemental sulfur. Most of the remaining H2S is converted to SO2 before being emitted to the atmosphere.

The other sources of acid gas to the SRUs are the refinery's sour water strippers, which were discussed above. As shown in the basic schematic below, the refinery has four (4) H2S treating appropriate temperature before it enters the catalytic reactors. The process stream must be heated to prevent any liquid sulfur from plugging individual catalyst pores, thereby deactivating the catalyst. Condensed sulfur from each of the three sulfur condensers flows through a seal pot to a heated sulfur vessel (T-7301), which is a horizontal tank that will be located below ground level in a concrete lined pit.

The liquid sulfur contains polysulfide (H2S2) and entrained H2S. The polysulfide will break down over time to release H2S. To prevent H2S and H2S2 concentrations from building up to explosive levels in the vapor space of the sulfur vessel, a purge of ambient air will be drawn through the vapor space of the tank with a steam ejector. This vent stream will be sent to the front end of the SRU for treatment. Sulfur that is pumped from this sulfur vessel to the existing sulfur storage tanks T-601 and T-602 will flow through a degassing unit to remove some of the remaining H2S and H2S2 in the liquid sulfur prior to storage and shipping. The primary component of this degassing unit is a Degassing Column (C7305) that utilizes a countercurrent flow of dry air to strip H2S from the liquid sulfur.

The tail gas from the third (final) sulfur condenser is sent to a TGTU followed by an incinerator and SOx scrubber for control of H2S, SO2, and other sulfur compounds in the tail gas. The equipment list for the proposed SRU is contained in the following table.

Equipment List for Sulfur Recovery Unit No. 73 (Process 13, System 10)

Description	Tag No.	Device No.	Dimensions/Rating
Construction of:			
• Waste Heat Boiler	E-7301	na.	60.5 MMBTU/Hr (unfired); Area/Shell: 7,450 ft^2
• No. 1 Condenser	E-7302	Dxx10	9.62 MMBTU/Hr; Area/Shell: 5,570 ft^2
• No. 2 Condenser	E-7303	Dxx13	6.41 MMBTU/Hr; Area/Shell: 4,890 ft^2
• No. 3 Condenser	E-7304	Dxx16	4.92 MMBTU/Hr; Area/Shell: 4,700 ft^2
• Waste Steam Condenser	E-7305	na.	4.92 MMBTU/Hr
• No. 1 Reheater	E-7306	na.	4.31 MMBTU/Hr (unfired; Area/Shell: 4,650 ft^2
• No.2 Reheater	E-7307	na.	3.50 MMBTU/Hr (unfired; Area/Shell: 3,800 ft^2
• Condensate Cooler	E-7308	na.	2.64 MMBTU/Hr; Area/Shell: 260 ft^2
• Blowdown Cooler	E-7309	na.	1.11 MMBTU/Hr; Area/Shell: 150 ft^2
• Reaction Furnace	F-7301	Dxxx9	Length: 36-ft; Dia: 9-ft
• Reaction Furnace Main Burner	F-7302	na.	92 MMBTU/Hr
• Sulfur Pit Vent Ejector	G-7301	Dxx21	Capacity: 14,650 SCFH; 4-in.dia. Inlet, 6-in.dia. Outlet, 3-in dia. 150 psig Steam Inlet
• Combustion Air Blower	K-7301/A	Dxxx8	Capacity: 791 MSCFH, Horsepower: 750 (electric; one spare)
• Process Air Booster Compressor	K-7302/A	Dxx23	Capacity: 4.2 MSCFH; Horsepower: 7.5 (electric: to sulfur degassing; one spare)
• Amine Acid Gas KO Drum Pump	P-7301/A	na.	Flow Rate: 30 gpm; 4HP

plants that utilize DEA or MEA to remove H2S and other reduced sulfur species from the refineries source off-gas streams. Each of these H2S plants has a dedicated amine regeneration unit. The average H_2S concentration in the acid gas streams from the H2S treating plants is greater than 90%. The refinery has three existing SRUs/TGTUs. The current acid gas distribution system for the SRUs is designed in a manner that allows the acid gas from the existing SWSs and H2S plants to be routed to any one of the SRUs. Its design allows the SRU's

to be filled out according to the Refinery's need for sulfur recovery capacity and to the condition of each of the SRU's at any given time. SRU feed can be routed to any of the three SRU's on flow or pressure control. Normally, one plant operates on pressure control to absorb the swings in H_2S production rate and the others operate on flow control. It is possible, however, to operate all three plants on flow control and allow the pressure in the H_2S system to fluctuate.

The existing acid gas manifold will be connected to the new SRU. However, the overhead stream from the new SWS will be connected directly to the new SRU instead of being connected into the existing acid gas manifold. The new SRU is designed to handle the high NH3 concentrations in the sour gas from the new SWS. Proposed condition S15.21 specifies that acid gas from SWS Plant No. 68 can only be directed to SRU No. 73. Proposed condition S18.20 specifies that the SRU No. 73 can receive acid gases from SWS Plant No. 68 as well as any of the existing SWSs and H2S plants.

Sulfur Recovery Plant No. 73 (Process 13, System 10)(AN 470738)

The primary purpose of the new SRU is to process H2S in the acid gas stream to liquid sulfur and process NH3 into nitrogen gas and water. A process flow diagram of the proposed new SRU and TGTU is contained in Appendix D. The proposed SRU is a modified Claus Unit that includes a thermal stage followed by two catalytic stages. The key reactions to the Claus process are identified below:

$H_2S + 3/2\ O_2 \rightarrow SO_2 + H_2O$ burns one-third of the H_2S to SO_2
$2H_2S + SO_2 \rightarrow 3/2S_2 + 2H_2O$ Claus conversion of H_2S and SO_2 to elemental sulfur

The thermal conversion process occurs in Reaction Furnace F-7301 in the front end of the SRU. The reaction furnace burns the H_2S rich acid gas stream and forms some elemental sulfur through the Claus reaction. The Claus reaction requires two moles of H_2S to react with one mole of SO_2, which is produced by oxidizing one third of the H_2S in the reaction furnace, leaving two-thirds to react with the SO_2. Any ammonia is thermally decomposed in the reaction furnace to nitrogen and water. The reaction furnace also contains a waste heat boiler section which utilizes some of the sensible heat of the hot gas stream to produce steam. Note that natural gas is required as an auxiliary fuel in the reaction furnace only during startup, shutdown, and malfunction. During normal operation, the H2S combustion in the furnace is self sustaining.

Elemental sulfur in the gas stream exiting the reaction furnace is condensed out in the first sulfur condenser (E-7302). The reaction furnace portion of the SRU will account for approximately 50-60% of the sulfur produced in the SRU. The second step in the SRU consists of two catalytic conversion beds (Reactors R-7301A and R-7301B). The catalysts in these beds promote the Claus reaction between H_2S and SO_2 at low temperatures to form elemental sulfur. Each of the catalytic reactors is preceded by a steam reheater (E-7306 and E-7307) and is followed by a sulfur condenser (E-7303 and E-7304). The reheaters are required to reheat the gas stream to the unit. These reducing gases heat the tail gas to the desired temperature and supplement the H2 that is present due to cracking of H2S in the Claus Reaction Furnace.

The tail gas flows from the RGG to Hydrogenation Reactor (R-7303), which contains a Co-Mo catalyst, where the sulfur compounds are hydrogenated or hydrolyzed to H2S according the following reactions:

$$S + H_2 \rightarrow H_2S$$
$$SO_2 + 3H_2 \rightarrow H_2S + 2H_2O$$
$$CS_2 + 2H_2O \leftrightarrow 2H_2S + CO_2$$
$$COS + H_2O \leftrightarrow H_2S + CO_2$$

In the reactor, carbon monoxide reacts to form additional hydrogen in the "water gas shift" reaction as follows:

$$CO + H_2O \leftrightarrow H_2 + CO_2$$

The tail gas from the Hydrogenation Reactor is cooled in the Reactor Effluent Cooler (E-7310) and the Desuperheater/Contact Condenser (C-7301). Desuperheating is accomplished in the lower section of the C-7301 by contact with an alkaline circulating solution (10% NaOH), which also prevents any SO2 breakthrough in the overhead gas from the condenser.

The overhead gas from the C-7301 condenser is routed to Amine Absorber C-7302 where H2S is absorbed in a circulating amine solution. The gas contains more CO2, produced by combustion of hydrocarbons in the acid gas feed and the RGG, than H2S. A Worley Parson's proprietary MDEA is utilized in the absorber since it is selective for H2S over CO2. Almost all of the H2S is absorbed in the amine while most of the CO2 "slips" by the amine. The overhead gas from the amine absorber is routed to Incinerator F-7302. A description of the incinerator follows this TGTU process description. The rich amine solution from the bottom of the absorber is regenerated in the Amine Regenerator C-7303. In the regenerator, the H2S and CO2 in the rich amine flowing down the stripper is stripped by steam flowing up the vessel. The low pressure steam is generated in the regenerator reboiler (E-7317).

The high H2S acid gas overhead stream from the amine regenerator is recycled back to the Amine Acid Gas Knockout Drum V-7301 at the front end of the SRU to be processed in the Claus Unit. The hot lean amine from the bottom of the regenerator flows through a lean amine/rich amine heat exchanger (E-7315) and a lean amine cooler (E7314) prior to entering the top of the amine absorber. Cooling the MDEA to near ambient temperature improves it's selectivity for H2S.

The equipment list for the proposed TGTU is contained in the following table.

Equipment List for Tail Gas Treating Unit (TGTU No. 73) (Process 13, System 11)

Description	Tag No.	Device No.	Dimensions/Rating
Construction of:			
• Desuperheater/Contact Condenser	C-7301	Dxx34	Ht.: 74-ft 2-in; Dia.: 9-ft 6-in

Description	Tag No.	Device No.	Dimensions/Rating
• NH_3 Acid Gas KO Drum Pump	P-7302/A	na.	Flow Rate: 20 gpm; 1.6HP
• Sulfur Degassing Pump	P-7303/A	na.	Flow Rate: 27 gpm; 4 HP
• Sump Pump for S-7301	P-7304	na.	Flow Rate: 20 gpm; 0.4HP
• Condensate Pump	P-7306/A	na.	Flow Rate: 22 gpm; 1.6 HP
• Sulfur Degassing Unit Package	PK-7301	Dxx22	Includes C-7305: Ht.34-ft.; Dia.2-ft.6-in. & E-7322, E-7323: 0.14 MMBTUH Each
• Air Dryer Package	PK-7303	na.	4.2 MSCFH
• No. 1 Converter	R-7301	Dxx12	Length: 21-ft 6-in; Dia.: 12-ft
• No. 2 Converter	R-7302	Dxx15	Length: 21-ft 6-in; Dia.: 12-ft
• Concrete Sump	S-7301	Dxx26	Length: 36-ft; Width: 16-ft; Depth: 16-ft
• Liquid Sulfur Vessel	T-7301	Dxx18	Length: 24-ft; Dia.:8-ft
• Amine Acid Gas K.O. Drum	V-7301	Dxxx6	Ht.: 10-ft 9-in; Dia.: 5-ft 0-in
• NH_3 Acid Gas K.O. Drum	V-7302	Dxxx7	Ht.: 8-ft 3-in; Dia.: 3-ft 6-in
• Steam Drum	V-7303	na.	Length: 14-ft; Dia.: 5-ft 6-in
• No. 1 Reheater Condensate Drum	V-7304	Dxx19	Ht.: 6-ft 2-in; Dia.: 2-ft
• No. 2 Reheater Condensate Drum	V-7305	Dxx20	Ht.: 6-ft 2-in; Dia.: 2-ft
• Blowdown Drum	V-7306	Dxx24	Ht.: 7-ft 8-in; Dia.: 2-ft
• Condensate Flash Drum	V-7307	Dxx25	Ht.: 8-ft 8-in; Dia.: 2-ft 6-in
• No.1 Sulfur Seal	V-7308	Dxx11	Ht.: 2-ft. 6-in.; Dia.: 2-ft.
• No.2 Sulfur Seal	V-7309	Dxx14	Ht.: 2-ft. 6-in.; Dia.: 2-ft.
• No.3 Sulfur Seal	V-7310	Dxx17	Ht.: 2-ft. 6-in.; Dia.:2-ft.

Note: Lengths and heights are measured from tangent to tangent Unless noted otherwise, all pumps and blowers are electrically powered

Tail Gas Treatment Unit No. 73 (Process 13, System 11)(470739)

Tail Gas Treatment Units (TGTUs) are designed to increase the overall sulfur recovery by processing the gas from the Claus unit final sulfur condenser. The proposed TGTU is a "SCOT" (Shell Claus Offgas Treatment) type. The plant was design by Worley Parsons. A process flow diagram for the proposed SCOT unit is contained in Appendix D. In a SCOT type TGTU, all of the sulfur compounds in the Claus tail gas are reduced to H2S, which is removed from the tail gas in an amine absorber.

As seen in the diagram, the tail gas from the third sulfur condenser (E-7304) in the proposed Claus SRU will be routed to the Reducing Gas Generator (RGG)(F-7303). In the RGG, natural gas is combusted substoichiometrically with steam to produce some reducing gas H2 and CO. The hot reducing gases are mixed with the tail gas coming from the third condenser in the Claus

Description	Tag No.	Device No.	Dimensions/Rating
• Anti-Foam Injection Package	PK-7302	na.	Tank: 1000 gal capacity; Pumps (two pumps, one spare): flow rate – 1.8 ft^3/day
• Hydrogenation Reactor	R-7303	Dxx31	Length:23-ft; Dia:12-ft
• Amine Surge Tank	T-7302	Dxx41	Ht: 21-ft 6-in; Dia.:20-ft
• Amine Storage Tank	T-7303	Dxx40	Ht.: 18-ft; Dia.:12-ft
• Reboiler Condensate Drum	V-7311	Dxx39	Ht.: 7-ft; Dia.: 2-ft 6-in
• Amine Drain Drum	V-7312	Dxx44	Length.: 11-ft; Dia.: 5-ft 6-in
• Booster Blower K.O. Drum	V-7313	Dxx33	Ht.: 15-ft; Dia.: 8-ft 6-in
• Regenerator Reflux Drum	V-7314	Dxx38	Ht.: 8-ft 10-in; Dia.: 3-ft
• Discharge Cooler KO Drum	V-7315	Dxx35	Ht.: 15-ft; Dia.: 8-ft 6-in
• Tempered Water Surge Drum	V-7316	na.	Ht.:21-ft 0-in; Dia.: 8-ft 0-in
• Flare KO Drum	V-7317	Dxx45	Ht.:10-ft 0-in; Dia.: 4-ft 0-in

Note: Lengths and heights are measured from tangent to tangent Unless otherwise noted, all blowers and pumps are electrically powered.

Tail Gas Treatment Unit No. 73 Incinerator (Process 13, System 12)(AN 480558)

The John Zink designed TGTU incinerator utilizes natural gas as the primary fuel to combust the tail gas from the TGTU to reduce the tail gas H2S concentration below the 2.5 ppmvd BACT limit and the 10 ppmvd limit of District Rule 468. A maximum of 41.9 mmbtu/hr (HHV) of natural gas will be utilized to achieve an thermal oxidization chamber exit temperature of 1450°F during normal operation. According to Chevron and John Zink, the 1450°F temperature is required to meet the BACT CO limit of 0.02 lb/mmbtu at the stack and the H2S limit of 2.5 ppmv (0% O2; 24-hr average).

As seen in the drawings in Appendix D, the natural gas burner, waste stream piping and air plenums are mounted directly on the front end of the 11'-0" OD by 33'-0" long thermal oxidization chamber. The internal diameter of the chamber is 10'-4". The chamber size is designed to provide a 2 second residence time. The burner is a Coen/Todd Combustion RMB (Rapid Mix Burner). With this low NOx burner, the air flow is divided into two separate streams. One air stream goes to the burner to provide proper air to fuel control in the burner. The second stream provides air for waste gas oxidization. This air stream is mixed directly with the waste gas immediately upon entrance to the thermal oxidization chamber to ensure high destruction rate efficiency (DRE) of the tail gas. As send in Appendix E, John Zink guarantees NOx emissions of 0.02 lb/mmbtu and CO emissions of 0.03 lb/mmbtu based on the lower heating value (LHV) of the natural gas fired in the incinerator.

Also included in the thermal oxidizer design is a brick refractory choke point with a no center obstructions. This simple choke point will allow the thermal oxidizer to be operated at the minimum temperature possible and still minimize the CO emission from the system. The exhaust gases from the oxidation chamber flow through a water-tube type waste heat recovery boiler, reducing their temperature from 1450°F to approximately 500°F. The boiler uses the waste heat from the flue gas to produce 175 psig saturated steam from deaerated boiler feed

Description	Tag No.	Device No.	Dimensions/Rating
• Amine Absorber	C-7302	Dxx36	Ht.: 61-ft; Dia.: 8-ft 6-in
• Amine Regenerator	C-7303	Dxx37	Ht.: 101-ft 10-in; Dia.: 6-ft 6-in
• Reactor Effluent Cooler	E-7310	na.	9.135 MMBTU/Hr (unfired); Area: 5,137 ft^2
• Contact Condenser Water Cooler	E-7312	na.	22.71 MMBTU/Hr; Area: 5410 ft^2
• Lean Amine Water Cooler	E-7314	na.	11.62 MMBTU/Hr; Area: 3,476 ft^2
• Lean/Rich Amine Exchanger	E-7315/A	na.	23.27 MMBTU/Hr; Area/Shell: 1,400 ft^2 (Duty is total for two shells.)
• Regenerator Overhead Condenser	E-7316	na.	19.86 MMBTU/Hr; Area: 1154 ft^2
• Regenerator Reboiler	E-7317	na.	31.53 MMBTU/Hr; Area: 4,000 ft^2
• Spent Caustic Cooler	E-7318	na.	1.5 MMBTU/Hr; Area: 410 ft^2
• Booster Blower Discharge Cooler	E-7319	na.	3.37 MMBTU/Hr; Area: 2036 ft^2
• Tempered Water Cooler	E-7320/A	na.	45.35 MMBTU/Hr. (Duty is total for two shells.)
• Reducing Gas Generator	F-7303	Dxx28	Length: 16-ft 1.5in; Dia.:7-ft 2-in, refractory
• Reducing Gas Generator Burner	F-7306	Dxx29	12.8 MMBTU/HR
• RGG Combustion Air Blower	K-7303/A	Dxx27	Capacity: 105.4 MSCFH; 23.1 HP (one spare)
• Booster Blower	K-7304/A	Dxx32	Capacity: 1030 MSCFH; 950 HP (one spare)
• Amine Drain Filter	K-7305	Dxx43	Ht.: 6-ft.10 in.; Dia.: 1-ft.2 in. (particulate filter)
• Amine Filter Package	K-7306A/B/C	Dxx42	Ht.: 6-ft.10 in.; Dia.: 3-ft.0 in. (particulate filter/guard filter)
• Contact Condenser Circulation Pump	P-7307/A	na.	Flow Rate: 1723 gpm; 89 HP (one spare)
• Desuperheater Circulation Pump	P-7308/A	na.	Flow Rate:1356 gpm; 90.4 HP (one spare)
• Rich Amine Pump	P-7309/A	na.	Flow Rate: 570 gpm; 45.8 HP (one spare)
• Wash Water Pump	P-7310/A	na.	Flow Rate: 166 gpm; 12.4HP (one spare)
• Lean Amine Pump	P-7311/A	na.	Flow Rate: 577 gpm; 45.6 HP (one spare)
• Regenerator Reflux Pump	P-7312/A	na.	Flow Rate: 38 gpm; 2.2HP (one spare)
• Drain Drum Pump	P-7313	na.	Flow Rate: 50 gpm; 2.6HP
• Amine Transfer Pump	P-7315	na.	Flow Rate: 90 gpm; 2.7HP
• Reboiler Condensate Pump	P-7316/A	na.	Flow Rate: 81 gpm; 8.3 HP (one spare)
• Tempered Water Pumps	P-7317/A/B	na.	Flow Rate: 2270 gpm; 300 HP (one spare)
• Flare KO Drum Pumps	P-7318/A	na.	Flow Rate: 40 gpm; 5.1 HP (one spare)

heat exchanger enters and travels down the inlet barrel of the scrubber where it collides with the NaOH scrubbing solution which is sprayed through a reverse jet nozzle up the inlet barrel. A turbulent zone is created at the gas/liquid interface. As the momentum of the gas and liquid balance, the liquid will change direction and fall to the bottom (sump) of the scrubber vessel. The gas continues downward until it exits the inlet barrel at which point it reverses direction and flows upward through the scrubber vessel. It exits the vessel through two Chevron-type vane separators (mist eliminators) installed near the top of the vessel to remove water droplets. The gas exits the scrubber at 125°F and flows through the heat exchanger, which heats it up to about 320°F, prior to flowing up the 150 foot tall stack.

An inventory of NaOH scrubbing solution is maintained in the sump of the scrubber vessel. 20° Baumé sodium hydroxide solution is added to maintain the pH of the scrubbing solution between 6.5 and 7.0. The scrubber liquid pH will be monitored continuously with two pH probes, located in the sump of the scrubber. A small amount of spent solution is continually removed from the bottom of the scrubber vessel in order to control the specific gravity of the solution. Makeup water will be added under some operating scenarios to replace water that is vaporized and lost out the stack. One claimed advantage of this type of scrubber is that the large bore reverse jet nozzle is less prone to plugging than packing or trays. Reliability is critical since the operation of the SRU depends on a functioning SO2 scrubber.

The key operating parameters for the scrubber are the liquid to gas ratio (L/G) and pH of the caustic solution. The L/G ratio is the ratio of scrubber liquid circulation flow rate (as gpm) to the quenched gas flow rate (as 1000 ACFM). The L/G must be high enough to fully quench the gas stream and scrub the SO2 without suppressing the pH in the turbulent contacting zone. According to the manufacturer, the scrubber design is based on an L/G of 64 gpm/1000 ACFM. This application for the Dynawave scrubber is different than the majority of other applications due to the low SO2 concentrations of the gas to be scrubbed. For El Segundo, the minimum recirculation rate based on an L/G of 64 is 29,676 ACFM x 64 gpm/1000 ACFM = 1900 GPM.

The equipment list for the proposed TGTU SOx Scrubber is contained in the following table.

Equipment List for TGTU No. 73 SO2 Scrubber (Process 13, System 13)

Description	Tag No.	Device No.	Dimensions/Rating
Construction of:			
• Tail Gas Heat Exchanger	E-7324	na.	6 MMBTU/HR (unfired)
• Solution Cooler	E-7325	na.	4 MMBTU/Hr (unfired)
• SO_2 Scrubber	V-7324	Dxx50	Ht.: 30-ft (T/T); Dia.: 8-ft
• Solution Circulation Pumps	P-7322 & P-7322A	na.	50 HP (one pump spares the other)

Startup and Shutdown of the SRU/TGTU

The SRU/TGTU is designed to operate for 5 years before a maintenance turnaround is required. The startup and shutdown (SU/SD) procedures are summarized below because pollutant emissions must be estimated for planned SU/SDs.

water. The exhaust gas from the waste heat boiler flows through the hot side of a welded plate type heat exchanger to further reduce the gases to roughly 300°F prior to the caustic scrubber. The exhaust gases from the scrubber flow through the cold side of the heat exchanger to increase the temperature to about 320°F before flowing to the stack.

The equipment list for the proposed TGTU incinerator is contained in the following table.

Equipment List for TGTU No. 73 Incinerator (Process 13, System 12)

Description	Tag No.	Device No.	Dimensions/Rating
Construction of:			
• Incinerator	F-7304	Dxx47	Length: 33-ft; Dia.: 11-ft, refractory; 41.9 MMBTU/HR
• Incinerator Waste Heat Boiler (with Steam Drum)	E-7321	na.	26.5 MMBTU/Hr (unfired)
• Incinerator Air Blower	K-7307 /A	Dxx48	Capacity: 628 MSCFH; 100 HP each (one blower spares the other)
• Incinerator Stack	F-7305	na.	Ht.: 150-ft; Dia.: 6-ft

The sulfur production capacity of the proposed SRU is 175 long ton per day (LTPD) when processing amine acid gas plus sour water and 235 LTPD when processing amine acid gas only. A long ton is 2240 pounds. The ammonia processing (destruction) capacity when processing sour water is 39 tons per day. The sulfur recovery efficiency of the SRU Claus Unit only is about 88% when processing sour water and amine acid gas and about 92% when processing only amine acid gas. As seen in Appendix E, Worley Parson's guarantees an SO2 concentration of 20 ppmv (0% O2, wet, 24-hr avg.) in the incinerator exhaust at the beginning of the SRU/TGTU run. They guarantee an SO2 concentration of 50 ppmv (0% O2, dry, 24-hr avg.) after 5 years of operation. Based on an SO2 concentration of 50 ppmvd at 0% O2, the total sulfur recovery efficiency of the SRU and TGTU combined is 99.97% when processing sour water and amine acid gas and 99.98% when processing only amine acid gas. According to Worley Parson's, the reduction in efficiency of the TGTU during the 5 year run is caused by degradation in the effectiveness of the hydrogenation catalyst due to oxidation, blockage of sites by pipe scale/debris, and channeling of process gas through the catalyst. Concentrations of COS increase in the hydrogenation reactor exhaust as the efficiency of the catalyst degrades. MDEA does not effectively absorb COS.

<u>Tail Gas Treatment Unit No. 73 - SOx Scrubber (Process 13, System 13)(AN 498947)</u>

As discussed earlier, Worley Parson's guarantees an SO2 concentration of 20 ppmv (0% O2, wet, 24-hr avg) in the incinerator exhaust at the beginning of the SRU/TGTU run and 50 ppmv (0% O2, dry, 24-hr avg) after 5 years of operation. A caustic SO2 scrubber is included downstream of the incinerator to further reduce the SO2 emissions to below 12 ppmv (0% O2, dry, 72-hr avg.) during the entire 5 years of operation between process turnarounds.

A drawing and process flow diagram for the proposed *MECS Dynawave* scrubber is contained in Appendix D. The SOx scrubber is a counter-current spray chamber type scrubber that utilizes a 20° Baumé sodium hydroxide (14.4 weight percent NaOH) scrubbing solution. The gas from the

LSFO Emergency Relief System (Flare) (Process 20, System 7)(AN 482504) and Refinery Blowdown Gas Recovery System (Process 20, System 10)(AN 482505)

[Note: The Refinery Blowdown Gas Recovery System is commonly referred to as the LSFO Vapor Recovery System (VRS). In the remainder of this evaluation, it will be referred to as the LSFO VRS.]

PRDs and maintenance vents from the following process units are currently connected into the LSFO VRS/Flare:

- No. 4 Crude Unit,
- Nos. 2 and Naphtha Hydrotreaters,
- Penex,
- Vacuum Gas Oil Desulfurizer,
- Nos. 5 and 6 H2S Plants,
- Steam Naphtha Reformer Hydrogen Plant, Sulfur Recovery unit No. 70, and
- C-810 Sour Water Concentrator.

New PRDs in the following permit units are proposed for connection to the LSFO VRS/Flare.

- Sour Water Stripper
- Sulfur Recovery Unit No. 73
- Tail Gas Treatment Unit No. 73

These process units are designed such that the set point for the new PRDs is higher than the pressures posed by all emergency, upset, and malfunction scenarios except fire. The PRDs will only open and release gas during a catastrophic fire in their respective unit. Proposed condition S56.1 specifies that the PRDs shall only open and release gas during a fire.

The table below shows the proposed emergency PRDs for the new SWS, SRU No. 73, and TGTU No. 73.

Inventory of Emergency PRDs for SWS, SRU, and TGTU

PERMIT UNIT	PRV LOCATION	SIZE (in.) (Inlet x Outlet)	SET PRESSURE (PSIG)	RELIEF DESTINATION
SRU	V-7301 Amine Acid Gas K.O. Drum	1.5 x 2	50	LSFO VRS/Flare
SRU	V-7302 NH_3 Acid Gas K.O. Drum	1 x 2	50	LSFO VRS/Flare
TGTU	C-7301	2 x 3	50	LSFO VRS/Flare
TGTU	C-7302	1.5 x 2.5	50	LSFO VRS/Flare
TGTU	V-7312 Amine Drain Drum	1.5 x 2.5	50	LSFO VRS/Flare
TGTU	V-7313 Booster Blower K.O Drum	1.5 x 2.5	50	LSFO VRS/Flare
TGTU	V-7314 Regenerator Reflux Drum	2 x 3	75	LSFO VRS/Flare
TGTU	V-7315 Discharge Cooler K.O. Drum	1.5 x 2.5	50	LSFO VRS/Flare
SWS	C-6810 Sour Water Stripper			LSFO VRS/Flare

Planned Startup

- Start TGTU incinerator (10,000 – 12,000 scfh)
- Open the bypass line from the TGTU Desuperheater/Condenser to the incinerator bypassing the amine absorber and begin caustic and water circulation in the Desuperheater/Condenser.
- Open the bypass line from the SRU No. 3 condenser to the TGTU Incinerator.
- Fire the TGTU Reducing Gas Generator (RGG) and SRU Reaction Furnace. For new refractory, the firing rate is left around 1000 scfh each for about 60 hours.
- After the refractory is cured, the RGG and reaction furnace firing rates are increased to 6 - 8,000 scfh and 11 – 13,000 scfh of natural gas, respectively. These rates are held for 30-40 hours to heat the SRU and TGTU to feed temperatures.
- Commission the amine absorber and regenerator and start flow through them.
- Transition to sub-stoichiometric operation of the RGG.
- Presulfide the TGTU Hydrogenation Reactor catalyst for about 20 hours by introducing a small slipstream of acid gas to convert metal oxides on the catalyst to metal sulfides.
- Route tail gas from the SRU to the TGTU.
- Replace natural gas to the SRU Reaction furnace with acid gas.

Planned Shutdown

- Reduce acid gas feed rates by one-third.
- Heat soak by increasing and maintaining the temperature to the Claus converters for 36 – 48 hours.
- Reduce Claus converter inlet temperatures and acid gas feed rate.
- Replace acid gas feed to the reaction with natural gas (12,000 scfh). Maintain sub-stoichiometric operation with 200 – 400 ppmv CO from the reaction furnace.
- Hotstrip the Claus Unit by sub-stoichiometric firing of natural gas in the reaction furnace until no more liquid sulfur is seen in the condenser drains and H2S in the SRU tail gas is 20 – 30 ppmv. Should take 24 – 36 hours.
- Bypass directly from the final SRU condenser to the TGTU incinerator.
- Slowly reduce and shutoff natural gas to the SRU reaction furnace while holding combustion air constant.
- Passivate the TGTU Hydrogenation Reactor catalyst for a period of 24 – 36 hours by reducing gas flow to the TGTU RGG until there is a slight excess of O2 in the exhaust. The amine absorber is bypassed because O2 and SO2 will damage the MDEA.
- Shutoff natural gas to the RGG and TGTU incinerator.

As shown in the "Calculation Section" of this evaluation, emissions of all pollutants are expected to be lower during SU and SD than normal operation since the SRU and TGTU are operating at a lower load and are not processing acid gas during the majority of the SU/SD periods. In addition, a few of the vessels, which will contain trace amounts of ammonia and H2S, will be purged with steam. The steam will condense on the way to the LSFO vapor recovery compressors and be pumped out to sour water.

Based on the estimated maximum velocity at the worst case load of 788,000 lb/hr and a tip exit diameter of 68 inches, the tip velocity was calculated to be 229 ft/sec, which is under the maximum allowable rate of 400 ft/sec.

$$Velocity = \left(\frac{(FlowRate lb/hr)(379 scf/lb-mole)(TemperatureatFlareR)}{(MW)(TipFlowAreaft2)(3600\,\mathrm{sec}/hr)(TemperatureStandardR)} \right)$$

$$Velocity = \left(\frac{(788{,}000 lb/hr)(379 scf/lb-mole)(659R)}{(17.8)(25.2 ft2)(3600\,\mathrm{sec}/hr)(532R)} \right) = 229 \text{ ft/sec}$$

The smokeless capacity of the flare varies depending on the properties of the flared stream. Based on the maximum continuous steam flow of 50,000 lbs/hr of steam, actual smokeless burning capacity varies from about 280,000 lb/hr (0.18 lb steam to 1 lb gas) to about 100,000 lb/hr (0.49 lb steam to 1 lb gas).

The flare is equipped with 4 pilots with a total combined natural gas flow of 800 scfh. Each of the headers in the relief header system is purged with natural gas. The total purge natural gas flow through the flare header system varies from 400 to 1380 scfh. There is no expected increase in the amount of purge natural gas through the flare header system since the new PRDs are being connected to existing headers such that the current purge gas flow will still be adequate to purge the entire header system. During normal operation of the system, the flare header purge gas will be captured by the LSFO VRS. The flare stack normally has a purge flow of 3600 – 5700 scfh of nitrogen. A flow of 500 – 800 scfh of natural gas is used when nitrogen is not available.

CALCULATIONS

The criteria air pollutant (CO, NOx, PM10, SO2, and VOC) and toxic air contaminant emissions for each of the new and modified permit units are contained in this section. These estimates include emissions for non-emergency operating conditions. Emissions from emergency events are not included since they cannot be accurately anticipated and estimated.

Criteria Air Pollutant Emission Estimates

The following table contains a summary of the type of criteria pollutant emissions that are emitted from each of the permit units that are included in this evaluation. A shaded square in this table indicates that the permit unit does not generate the subject criteria pollutant.

Permit Unit	CO	NOx	PM10	SOx	VOC
Sour Water Stripper					Fugitive (1)
Sulfur Recovery Unit				Process Vent	Fugitive (1)
Tail Gas Treatment Unit					Fugitive (1)
TGTU Incinerator	Comb.	Comb.	Comb.		Comb.
SOx Scrubber					

PERMIT UNIT	PRV LOCATION	SIZE (in.) (Inlet x Outlet)	SET PRESSURE (PSIG)	RELIEF DESTINATION
SWS	K-6801Sour Water Pre-Filter			LSFO VRS/Flare
SWS	K-6801A Sour Water Pre-Filter			LSFO VRS/Flare
SWS	V-6801 Oil Separator			LSFO VRS/Flare

(1) PRV in steam/condensate service, but is routed to flare in event of internal hydrocarbon leak in equipment.

The LSFO Emergency Flare system was originally installed in 1973 to handle emergency waste gas releases in the event of a general power failure or process upset in the No. 4 Crude Unit, No. 12 Naptha Hydrotreater, SNR Hydrogen Plant, Isomax VRDS, Isomax VGO, No. 5 H2S Recovery Plant, and the pentanes plus plant. Schematics of the LSFO Flare System and the LSFO VRS are shown in Appendix F. The LSFO Flare and VRS are interconnected with the FCCU and Alky Flares and VRSs. The flares are interconnected so that one of the flares can be shutdown for maintenance or repairs without shutting down all of the equipment connected to the flare. The valves to switch flow from one flare to another are manual.

The main flare relief header is a 36 inch header that connects into the LSFO Flare knock drum (V-2500). A 42 inch line goes from the knockout pot to the base of the flare. The base of the flare contains a 64 inch water seal to maintain back pressure on the flare header. The LSFO VRS was recently upgraded by the replacement of three reciprocating compressors with a capacity of 2 MMSCFD each by three reciprocating compressors with a capacity of 4 MMSCFD each. These three electrically driven compressors (K-2006, K-2007, and K-2008) operate in parallel. The K-2005 compressor in the Coker Blowdown System (Process 2, System 5) functions as a backup compressor. The compressors, which pull suction on the flare relief system, discharge the compressed gas to the No. 5 H2S Plant. The goal of the recovery system is to keep the pressure of the flare header below 64 inches water column to prevent relief gases from flowing through the water seal into the flare. The compressors can be operated independently or concurrently at any given time on "as needed" basis depending on the volume of gases available for recovery.

The flare stack is a freestanding stack fitted with a Flaregas FS Type tip, which is equipped with 100 "flarejectors". This cluster of "flarejectors" are designed to provide thorough mixing of steam, air, and gas. The 150 psi steam that is supplied to these "flarejectors" aspirates air and gas through the "flareejectors". The upper section of the flare tip has a conical shape with a maximum diameter of 68 inches. The flare stack is equipped with a "flarex" (molecular) seal. The stack is continuously purged with nitrogen. The nitrogen in conjunction with the molecular seal prevents air from entering into the flare stack.

The capacity of a flare is limited by the hydraulics of the relief system and the flare tip velocity. As required by 40CFR60 Subpart A, the flare tip velocity should be maintained below 400 ft/sec. The current maximum loads to the flare are 788,800 lb/hr (@ MW = 17.8) during a total refinery power failure and 960,000 lb/hr (@ MW = 105) during a reflux failure at the No. 4 Crude Unit. The SRU and SWS will only vent to the flare in the case of a catastrophic fire so the maximum load to the flare is not impacted by the connection of the new emergency PRVs. The flare tip velocity at the maximum load is 244 ft/sec, which is well below the maximum flare tip velocity of 400 ft/sec.

Permit Unit	Estimated VOC Emissions (lb/day)(1)		Change in VOC Emissions	
	Pre-Mod	Post-Mod	(lb/day)(1)	(lb/year)
LSFO Flare	24.5	24.5	0	0
LSFO VRS	0.38	0.38	0	0
Total			**14.2**	**5108**

(1) 30 day average

Fugitive VOC emissions are the only criteria pollutant emissions for the following permit units: .

- Sour Water Stripper (Process 12, System 28 – new)
- SRU No. 10 (Process 13, System 1)
- SRU No. 20 (Process 13, System 2)
- SRU No. 70 (Process 13, System 4)
- LSFO VRS (Process 20, System 10)

SRU Process Vent

As mentioned previously, the SRU is the source of the sulfur for the vast majority of the SO2 emissions from the TGTU Incinerator. The natural gas combusted in the incinerator contains low concentrations of reduced sulfur species. Since SO2 emissions are measured at the stack of the TGTU Incinerator, the emissions are normally tracked in the Districts NSR database as incinerator emissions.

Combustion Devices: TGTU Incinerator and LSFO Flare

TGTU Incinerator:

As discussed in more detail in the evaluation of Regulations XIII and XX below, the incinerator will be conditioned with the following emission limits for CO, NOx, and SO2:

Chevron proposes that following BACT emission limits:

- CO - 0.03 lb/MMBtu NG (24-hour average)
- NOx - 0.02 lb/MMBtu NG (24-hour average)
- SO_2 - 12 ppmvd (0% O2; 72-hour average)

The incinerator must comply with the CO, NOx, and SOx emission limits at all times including startup and shutdown of the SRU/TGTU. As seen in the table below, the maximum potential to emit (PTE) emission estimates for CO, NOx and SO2 are based on these emission limits. PM10 and VOC emission estimates are based on emission factors. Natural gas combustion emission factors from the District's annual emission reporting (AER) program are utilized since the primary fuel for the incinerator is natural gas.

The composition of the TGTU tail gas must also be evaluated to determine if it will cause additional PM10 and VOC emissions. Chevron modeled multiple SRU/TGTU operating scenarios. The tail gas composition for the two scenarios are shown in the table below.

Permit Unit	CO	NOx	PM10	SOx	VOC
LSFO Flare	Comb.(3)	Comb. (3)	Comb. (3)	Comb. (3)	Fugitive & Comb.
LSFO VRS					Fugitive

1.) Fugitive – emissions due to leakage from fugitive components such as valves, flanges/ connectors, pumps, compressors, process drains, etc.
2.) Process Vent – The source of most of the SO_2 that is emitted from the TGTU incinerator and SOx Scrubber is the SRU. The process vent stream from the SRU contains high concentrations of H2S. Most of this H_2S is removed in the TGTU. Most of the remaining H2S is converted to SO_2 in the incinerator. For Regulation XIII (NSR), these SO_2 emissions are ascribed to the incinerator.
3.) Comb. – emissions from combustion of natural gas in the LSFO Flare pilots and incinerator.

Fugitive VOC Emissions

Many of the subject permit units contain fugitive components (valves, pumps, connectors, etc.). Fugitive components that handle gases or liquids that contain VOCs may periodically leak VOC containing gas or liquid to the atmosphere. VOC emissions for these fugitive components are estimated by multiplying the total number of each fugitive component type by an appropriate emission factor. Baseline (pre-modification) emission estimates are based on a count of all of the existing fugitive components in the permit unit, which handle VOC containing liquids or gases. The post-modification count accounts for all of the fugitive components that are removed from and added to the permit unit as a result of the proposed modifications to that unit. 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.

The following table contains a summary of the estimated fugitive VOC emissions for each of the subject permit units. For units undergoing modifications, the table contains the pre- and post-modification fugitive component counts. The detailed fugitive component counts and VOC emissions estimates are contained in Appendix G.

Estimated Pre- and Post-Modification VOC Emissions from Fugitive Components on a Permit Unit Basis

Permit Unit	Estimated VOC Emissions (lb/day)(1)		Change in VOC Emissions	
	Pre-Mod	Post-Mod	(lb/day)(1)	(lb/year)
Sour Water Stripper	0	3.52	+3.52	+1270
Sulfur Recovery Unit	0	0.66	+0.66	+240
Tail Gas Treatment Unit	0	10.0	+10.0	+3598
SRU No. 10	2.73	2.73	0	0
SRU No. 20	2.73	2.73	0	0
SRU No. 70	7.12	7.12	0	0

btu/scf and an HHV of 1014 btu/scf. An HHV of 1014 btu/scf is conservatively used in the emission estimates shown in the table below.

TGTU Incinerator: Tail Gas/Combustion Emission Estimate

CAP Type	NG Flow (MMCF/ hr)(1)	Emission Factor or Limit			Emissions		
		lb/ MMcf	lb/ MMBtu	Limit (ppmv)	lb/hr	lb/day (5)	lb/yr
CO	4.13×10^{-2}	na.	0.03 (4)	na.	1.13	27.4	9871.
PM	4.13×10^{-2}	7.5(2)	na.	na.	na.	na.	na.
PM10	4.13×10^{-2}	7.5 (3)	na.	na.	0.31	7.5	2710.
VOC	4.13×10^{-2}	7 (2)	na.	na.	0.29	7.0	2530.
NOx	4.13×10^{-2}	na.	0.02 (4)	na.	0.76	18.4	6640.
SOx	4.13×10^{-2}	na.	na.	12	2.44 (6)	59.4	21370.

(1) Incinerator design based on a maximum firing rate of 41.9 MMBtu/hr of natural gas with an HHV of 1014 btu/scf. See Appendix E.

(2) Default EF from Instruction Book for AER Program (Default EF for NG combustion; external, other)- see Appendix I

(3) PM_{10} = 1.0 X PM emissions (based on CARB size distribution for incinerator – gaseous waste) – see Appendix I

(4) John Zink's guarantee is based on the LHV of the natural gas. The maximum firing rate is 37.8 MMBtu/hr (LHV) based on natural gas with an LHV of914 btu/scf. See Appendix E.

(5) 30 day average

(6) Average hourly emission based on exhaust gas SO2 concentration of 12 ppmv

LSFO Flare:

This section contains an estimate of criteria pollutant emissions from non-emergency operation of the LSFO Flare. These non-emergency emissions are from the combustion of pilot and purge gas streams to the flare. Criteria pollutant emissions from the combustion of gases generated from process upsets or equipment malfunctions are not included in the Regulation XIII emission estimates.

The estimated criteria pollutant emissions from the combustion of the pilot and sour water surge drum (header) purge gas streams in the LSFO Flare is shown in the following table. The header purge gas is normally captured in the vapor recovery system so it does not normally flow to the flare. As a worst case, it will be assumed that this purge gas is combusted in the flare. Natural gas is used both as the pilot gas and the header purge gas. The design pilot gas flow rate is 38 lb/hr (800 scfh). The purge gas flow rate varies from 400 to 1380 scfh. The maximum flow rate of 1380 scfh is used in the estimation of CAP emissions. The new PRDs will be connected into the existing gas header so they will not cause an increase in the amount of purge gas through the header.

The estimate of combustion emissions from normal operation of the flare (as shown in the table below) is based on the estimated combined pilot and flare purge gas flow of 2180 scfh [800 scfh + 1380 scfh] and utilizes District AER/Rule 1118 emission factors for natural gas combustion. Note that the proposed connection of new PRDs does not cause any increase in the normal emissions from the flare since there is no change in the amount of pilot gas, purge gas, or fugitive components. The PRDs are included in the fugitive component count for the process units.

Composition of TGTU Tail Gas

Component	Scenario No. 1 (1)			Scenario No. 2 (2)		
	Flow Rate (scf/hr)	Conc. (vol %)	Heat Input (MMBtu/hr) (3)	Flow Rate (scf/hr)	Conc. (vol %)	Heat Input (MMBtu/hr) (3)
Carbon Monoxide (CO)	205	0.02	0.07	273	0.03	0.09
Carbon Dioxide (CO2)	54652	6.3	0	56395	6.4	0
Hydrogen (H2)	27478	3.2	8.9	33352	3.8	10.8
Water Vapor (H2O)	45670	5.3	0	46390	5.3	0
Nitrogen (N2)	732986	85.1	0	738671	84.4	0
Carbonyl Sulfide (COS)	15	0.002	0.01	49	0.01	0.03
Hydrogen Sulfide (H2S)	8	0.0009	0.005	8	0.001	0.005
Total	**861000**	**100**	**9.0**	**875100**	**100**	**11.0**

(1) Highest natural gas firing case – 41.9 MMBtu/hr
(2) Highest tail gas flow rate case – occurs while processing 175 LTPD of sulfur and 35 LTPD of ammonia at the end of run for the SRU/TGTU.
(3) Based on high heating value

Note that the acid gas to the SRU contains VOC but essentially all of the VOC is oxidized in the reaction furnace (F-7301). Therefore, the tail gas to the incinerator does not contain a significant concentration of VOC. Under both of the scenarios shown in the table, nitrogen, carbon dioxide, and water comprise more than 96% of the tail gas on a volume basis. These inert compounds are not expected to contribute to PM10 or VOC formation. The remaining 3 – 4 percent of the tail gas is carbon monoxide and hydrogen with trace amounts of carbonyl sulfide and hydrogen sulfide. These constituents are also not expected to contribute to PM10 or VOC concentrations. CO and H2 will be oxidized to CO2 and H2O, respectively. COS will be oxidized to CO2 and SO2. H2S will be oxidized to H2O and SO2.

As seen in the table, the heat content of the tail gas varies from 9 to 11 MMBtu/hr for these two modeled scenarios. Hydrogen supplies 98 – 99 % of this heat content. The overall high heating value of the tail gas for these modeled scenarios is 11 and 13 btu/scf. The heat content of the tail gas will assist in maintaining a firebox temperature of 1450°F but will not significantly impact the formation of PM10 or VOC in the incinerator. Since the tail gas is not expected to impact PM10 and VOC in the incinerator, estimation of PM10 and VOC using the District's AER emission factors for natural gas combustion is appropriate.

The operating scenario with the highest estimated flue gas flow is the one with the incinerator firing 41.9 mmbtu/hr of natural gas, which will be the maximum permitted natural gas firing rate. The flue gas flow under this operating scenario is 20,086 dscfm with stoichiometric combustion (0% O2). This flue gas flow is utilized in the emission estimates shown in the table below. A high heating value (HHV) of 1050 btu/scf is routinely used in emission estimates for natural gas combustion. Chevron reports that the average HHV for natural gas utilized at the refinery is 1014 btu/scf. For the design of the incinerator, John Zink assumed natural gas with an LHV of 914

Since the TACs are present in widely variable concentrations in the various process and waste streams, an emission factor will be multiplied by the concentration of the TAC in the stream flowing through a fugitive component to estimate the TAC emitted from that component. These estimates of yearly emissions are utilized to evaluate the cancer/chronic risk for each permit unit. To evaluate acute risk, the yearly estimates are converted to hourly emissions by dividing by 365 days/yr and 24 hrs/day.

Sour Water Stripper (SWS)

The TAC concentrations for streams that must be evaluated in the SWS are shown in the following table. The BTEX concentrations are based on a 2001 sample of existing sour water streams. The H_2S and NH_3 concentrations are based on the engineering design for the SWS.

Sour Water Stripper: TAC Composition of Streams

Stream	Composition (%)					
	H2S	NH3	Benzene	Ethyl Benzene	Toluene	Xylene
SW Feed	2.5	1.5	0.28	0.21	0.89	1.0
SWS Overhead (OH)	22.1	17.1				
SW OH Accumulator Vapor	51.0	30.6				
SW OH Accumulator Liquid	7.7	10.4				
Recovered Oil			0.56	0.42	1.8	2.0

The estimated TACs for the SWS are shown in the following table.

Sour Water Stripper: Estimated TAC Emissions

Component Type	Total Number	Emissions (lb/yr)					
		H2S	NH3	Benzene	Ethyl Benzene	Toluene	Xylene
Sour Water Feed							
Flange/Component	221	8.3	5.0	0.9	0.7	3.0	3.3
Pump	2	4.0	2.4	0.4	0.3	1.4	1.6
Valve	106	8.0	4.8	0.9	0.7	2.8	3.2
Drains (1)	6	12.0	7.2	1.3	1.0	4.3	4.8
SWS Overhead (OH)							
Flange/Component	61	20.2	15.6	0	0	0	0
Valve	25	127.	98.3	0	0	0	0
SW OH Accumulator Vapor							
Flange/Component	28	21.4	12.9	0	0	0	0
Valve	17	328.	197.	0	0	0	0

LSFO Flare: Estimated Emissions from Combustion of Pilot/Purge Gas

Pollutant	Total Pilot/Purge Gas (MMscf/day)	Emission Factor (lb/MMscf)	Emissions (lb/day)	Emissions (lb/yr)
NOx	0.052	130	6.76	2467
SOx	0.052	0.83	0.04	15
CO	0.052	35	1.82	664
PM10	0.052	7.5	0.39	142
VOC	0.052	7	0.36	133

Total VOC emissions for the flare are 24.9 lb/day including the 24.5 lb/day from fugitive components and the 0.36 lb/day from combustion of pilot and purge gas.

Toxic Air Contaminant (TAC) Emissions

For District Rule 1401, a health risk assessment (HRA) must be performed for each individual permit unit for which there is an increase in TACs. The methodology and results for the health risk assessment are included under Rule 1401 in the Rule Compliance Review section of this evaluation. For this project, TAC emissions must be estimated and an HRA must be performed for following new permit units:

- Sour Water Stripper [Process 12, System 28 (new)]
- Sulfur Recovery Unit No. 73 [(Process 13, System 10 (new)]
- Tail Gas Treatment Unit No. 73 [(Process 13, System 11 (new)]
- TGTU Incinerator [Process 13, System 12 (new)]

For the existing SRUs, LSFO Flare, and VRS, there is not expected to be any increase in TAC emissions during normal operation since there are no proposed physical or operational modifications of these permit units.

All of the TAC emissions for the SWS, SRU, and TGTU will be from fugitive components such as flanges, connectors, valves, pumps, and drains. There are currently no emission factors that are directly applicable to these streams. The only available emission factors for fugitive components are those developed for components in organic liquid and vapor service that are used for estimation of VOC emissions. These organic liquid/vapor factors are the best available for estimation of emissions of TACs from fugitive components in these permit units. The emission factors that are used for estimation of fugitive TAC emissions are shown in the following table.

Emission Factors Utilized for Estimation of Fugitive TAC Emissions

Component Type	Stream Type	Comparable Organic Stream	Emission Factor (lb/yr)
Flange/Connector	All	All	1.5
Valve	Vapor Streams	Gas/Vapor	23
Valve	Liquid Streams	Heavy Liquid	3
Pump	Liquid Streams	Heavy Liquid	80
Drains	Liquid Streams	Liquid	80

Stream	Composition (%)				
	H2S	NH3	CS2	HCN	Hexane
Vent gas from Degassing Contactor (C-7305) to Reaction Furnace (F-7301)	0.11				

The estimated TACs for the SRU are shown in the following table.

Sulfur Recovery Unit No. 73: Estimated TAC Emissions

Component Type	Total Number	Emissions (lb/yr)				
		H2S	NH3	CS2	HCN	Hexane
Amine acid gas to the Reaction Furnace (F-7301)						
Flange/Component	74	85	0.0	0.0	0.01	0.2
Valve	44	773	0.0	0.0	0.1	2.1
NH3 acid gas to the Reaction Furnace (F-7301)						
Flange/Component	63	37.1	35.2	0	0	0
Valve	36	325	308	0	0	0
Liquid pumpout from the amine and NH3 acid gas knockout drums						
Flange/Component	112	4.2	2.5	0	0	0
Valve	55	4.1	2.5	0	0	0
Pump	4	8.0	4.8	0	0	0
Drain (1)	20	40.	24.	0	0	0
Process gas from Reaction Furnace (F-7301) to No. 1 Condenser (E-7302)						
Flange/Component	3	0.2	0.0	0.04	0	0
Valve	1	1.0	0.0	0.2	0	0
Process gas from No. 1 Condenser (E-7302) to No. 1 Converter (R-7301)						
Flange/Component	9	0.6	0.0	0.1	0	0
Valve	2	2.2	0.0	0.4	0	0
Process gas from the No. 1 Converter (R-7301) to No. 2 Condenser (E-7303)						
Flange/Component	3	0.1	0.0	0.00	0	0
Valve	1	0.6	0.0	0.02	0	0
Process gas from No. 2 Condenser (E-7303) to the No. 2 Converter (R-7302)						
Flange/Component	9	0.4	0.0	0	0	0
Valve	2	1.2	0.0	0	0	0
Process gas from the No. 2 Converter (R-7302) to the No. 3 Condenser (E-7304)						
Flange/Component	4	0.1	0.0	0.00	0	0
Valve	1	0.3	0.0	0.00	0	0
Process gas from the No. 3 Condenser (E-7304) to the TGTU						
Flange/Component	6	0.1	0.0	0.00	0	0

Component Type	Total Number	Emissions (lb/yr)					
		H2S	NH3	Benzene	Ethyl Benzene	Toluene	Xylene
SW OH Accumulator Liquid							
Flange/Component	72	8.3	11.2	0	0	0	0
Valve	42	9.7	13.1	0	0	0	0
Drains (1)	3	18.5	25.0	0	0	0	0
Recovered Oil							
Flange/Component	34	0	0	0.3	0.2	0.9	1.0
Valve	25	0	0	0.4	0.3	1.4	1.5
Drains (1)	2	0	0	0.9	0.7	2.9	3.2
Total		**565**	**393**	**5.1**	**3.9**	**16.7**	**18.6**

(1) The eleven drains for this permit unit were split between the three liquid streams based on the valve distribution for the three streams. For example, 6 drains were assigned to the sour water stream based on ((106 sour water feed valves)/(173 total liquid valves)) * (eleven total drains).

Sulfur Recover Unit No. 73

The TAC concentrations for streams that must be evaluated in the SRU are shown in the following table. The concentrations are based on the engineering design for the SRU.

Sulfur Recovery Unit No. 73: TAC Composition of Streams

Stream	Composition (%)				
	H2S	NH3	CS2	HCN	Hexane
Amine acid gas to the Reaction Furnace (F-7301)	76.4			0.01	0.21
NH3 acid gas to the Reaction Furnace (F-7301)	39.3	37.2			
Liquid pumpout from the amine and NH3 acid gas knockout drums	2.5	1.5			
Process gas from Reaction Furnace (F-7301) to No. 1 Condenser (E-7302)	4.2		0.08		
Process gas from No. 1 Condenser (E-7302) to No. 1 Converter (R-7301)	4.8		0.09		
Process gas from the No. 1 Converter (R-7301) to No. 2 Condenser (E-7303)	2.6		0.09		
Process gas from No. 2 Condenser (E-7303) to the No. 2 Converter (R-7302)	2.7		0.01		
Process gas from the No. 2 Converter (R-7302) to the No. 3 Condenser (E-7304)	1.3		0.01		
Process gas from the No. 3 Condenser (E-7304) to the TGTU	1.3		0.01		
Molten Sulfur from Sulfur Pit (T-7301) to the Degassing Contactor (C-7305)	0.03				

The estimated TACs for the TGTU are shown in the following table.

Tail Gas Treatment Unit No. 73: Estimated TAC Emissions

Component Type	Total Number	Emissions (lb/yr)		
		H2S	NH3	CS2
SRU tail gas to the Reducing Gas Generator (F-7303)				
Flange/Component	7	0.1	0	0.00
Valve	5	1.5	0	0.01
Tail gas from RGG (F-7303) to Hydrogenation Reactor (R-7303)				
Flange/Component	15	0.3	0	0.00
Valve	7	1.9	0	0.02
Tail gas from Hydrogenation Reactor (R-7303) to Desuperheater/ Condenser (C-7301)				
Flange/Component	10	0.3	0	0
Valve	5	2.3	0	0
Desuperheater/ Condenser (C-7301) (Vapor Portions)				
Flange/Component	61	2.1	0	0
Valve	29	15.3	0	0
Tail Gas from Desuperheater/ Condenser (C-7301) to Amine Absorber (C-7302)				
Flange/Component	95	3.6	0	0
Valve	42	24.2	0	0
Vapor stream from Amine Absorber (C-7302)				
Flange/Component	66	1.3	0	0
Valve	31	9.3	0	0
Liquid stream from Amine Absorber (C-7302)				
Flange/Component	46	0.2	0	0
Valve	27	0.3	0	0
Drain (1)	8	2.2	0	0
Rich amine from Amine Absorber (C-7302) to Amine Regenerator (C-7303)				
Flange/Component	151	1.6	0	0
Valve	65	1.4	0	0
Pump	2	1.1	0	0
Drain (1)	19	10.6	0	0
Vapor from Amine Regenerator (C-7303)				
Flange/Component	46	6.5	0	0
Valve	23	50	0	0
Regenerator Reflux Drum (V-7314) Overhead Vapor				
Flange/Component	40	29.8	0	0
Valve	26	297	0	0
Regenerator Reflux Drum (V-7314) Liquid				
Flange/Component	18	0.04	0	0
Valve	17	0.1	0	0

Component Type	Total Number	Emissions (lb/yr)				
		H2S	NH3	CS2	HCN	Hexane
Valve	4	1.2	0.0	0.01	0	0
Molten Sulfur from Sulfur Pit (T-7301) to the Degassing Contactor (C-7305)						
Flange/Component	20	0.01	0	0	0	0
Valve	8	0.01	0	0	0	0
Drain (1)	3	0.07	0	0	0	0
Vent gas from Degassing Contactor (C-7305) to Reaction Furnace (F-7301)						
Flange/Component	4	0.01	0	0	0	0
Valve	2	0.1	0	0	0	0
Total		**1285**	**377**	**0.77**	**0.11**	**2.3**

(1) The 23 drains for this permit unit were split between the two liquid streams based on the valve distribution for the two streams.

Tail Gas Treating Unit No. 73

The TAC concentrations for streams that must be evaluated in the TGTU are shown in the following table. The concentrations are based on the engineering design for the TGTU.

Tail Gas Treatment Unit No. 73: TAC Composition of Streams

Stream	Composition (%)		
	H2S	NH3	CS2
SRU tail gas to the Reducing Gas Generator (F-7303)	1.3		0.01
Tail gas from RGG (F-7303) to Hydrogenation Reactor (R-7303)	1.2		0.01
Tail gas from Hydrogenation Reactor (R-7303) to Desuperheater/ Condenser (C-7301)	2.0		
Desuperheater/ Condenser (C-7301)	2.3		
Tail Gas from Desuperheater/ Condenser (C-7301) to Amine Absorber (C-7302)	2.5		
Vapor stream from Amine Absorber (C-7302)	1.3		
Liquid stream from Amine Absorber (C-7302)	0.35		
Rich amine from Amine Absorber (C-7302) to Amine Regenerator (C-7303)	0.7		
Vapor from Amine Regenerator (C-7303)	9.4		
Regenerator Reflux Drum (V-7314) overhead vapor	49.7		
Regenerator Reflux Drum (V-7314) liquid	0.16		
Bottoms from Hydrogenation Reactor (R-7303)	0.01		
Liquid from flare knockout drum (V-7317)	1.5	2.5	

Toxic Air Contaminant	CAS No.	Emission Factor	Est. TAC Emission	
		lb/MMcf	lb/hr	lb/yr
Acrolein (1)	107-02-8	2.70E-03	1.12E-04	9.77E-01
Propylene (1)	115-07-1	5.30E-01	2.19E-02	1.92E+02
Toluene (1)	108-88-3	2.65E-02	1.09E-03	9.59E+00
Xylenes (Total) (1)	1330-20-7	1.97E-02	8.14E-04	7.13E+00
Ethylbenzene (1)	100-41-4	6.90E-03	2.85E-04	2.50E+00
Hexane (1)	110-54-3	4.60E-03	1.90E-04	1.66E+00
Hydrogen Sulfide (H2S) (2)	7783-06-4	na.	2.70E-01	2.37E+03

(1) Based on natural gas combustion at a rate of 41.9 MMBtu/hr.
(2) Based on an H2S emission limit of 2.5 ppmvd at 0% O2 and an incinerator stack flow of20,086 dscfm with zero excess air.

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. The SRU SOx Scrubber was not included in the original PRO Project proposal so Chevron is preparing an addendum to the FEIR to reflect the change in the original project proposal. The SRU related permits will not be issued until the addendum is certified.

The SRU 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.

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. Public notice is not required under this clause since none of the permit units to be modified under this project are located with 1000-foot of a school. As seen in Appendix J, the nearest school is 1023 meters (3355 feet) away from the new SWS, SRU, TGTU, or TGTU Incinerator.

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 all of the permit units listed in the table in the introduction section of this

Drain (1)	5	0.6	0	0
Bottoms from Hydrogenation Reactor (R-7303)				
Flange/Component	6	0.00	0	0
Valve	2	0.00	0	0
Drain (1)	1	0.01	0	0
Liquid from flare knockout drum (V-7317)				
Flange/Component	68	1.5	2.6	0
Valve	32	1.4	2.4	0
Drain (1)	9	10.8	18	0
Total		**477**	**23**	**0.03**

(1) The 42 drains for this permit unit were split between the five liquid streams based on the valve distribution for the five streams.

TGTU Incinerator

As described in the Process Description section, natural gas is utilized as the primary fuel of the incinerator. Tail gas from the TGTU is added into the combustion chamber downstream of the burner. TAC emissions for the incinerator are products of incomplete combustion (PICs) from the natural gas burner and H2S in the TGTU tail gas that is not combusted in the incinerator. of TGTU Tail Gas in the incinerator. TACs emitted in the exhaust of the incinerator are a combination of TACs that are products of incomplete combustion (PICs) from the natural gas burner and TAC(s) in the tail gas treated in the incinerator. In the incinerator, the products of combustion from the natural gas burner are mixed with the tail gas from the TGTU to oxidize the majority of the residual H2S and COS in the tail gas to form SO2. H2S is a TAC under Rule 1401. COS is not a TAC.

The following table contains an estimate of the annual emissions of TACs from the combustion of natural gas in the incinerator. The emissions factors utilized in this estimate were developed by the California Air Resources Board for use in AB2588 emissions inventories for natural gas fired external combustion equipment. Documentation of these emission factors, as compiled by the Ventura County Air Pollution Control District, is contained in Appendix I. This maximum potential TAC emissions estimate is based on combustion of 41.9 MMBtu/hr of natural gas with an HHV of 1014 btu/scf (0.0413 MMscf of natural gas per hour) for 24 hours per day on 365 days per year.

TGTU Incinerator: Estimated TAC Emissions

Toxic Air Contaminant	CAS No.	Emission Factor	Est. TAC Emission	
		lb/MMcf	lb/hr	lb/yr
Benzene (1)	71-43-2	5.80E-03	2.40E-04	2.10E+00
Formaldehyde (1)	50-00-0	1.23E-02	5.08E-04	4.45E+00
PAH (excluding Napthalene) (1)	na.	1.00E-04	4.13E-06	3.62E-02
Naphthalene (1)	91-20-3	3.00E-04	1.24E-05	1.09E-01
Acetaldehyde (1)	75-07-0	3.10E-03	1.28E-04	1.12E+00

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 not required under this clause since none of the new or modified sources included in this evaluation have emission increases that exceed the 212(g) thresholds.

Regulation IV - PROHIBITIONS

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%.

Fugitive Components: Visible emissions are not expected from any of the new fugitive components installed under this project.

TGTU Incinerator: The permit for the incinerator will be issued with a minimum temperature limit of 1450°F to assure efficient combustion of the TGTU tail gas. The incinerator permit will also be conditioned with an H_2S limit of 2.5 ppmv (0%O_2, dry, 24-hr average) and a CO limit of 0.02 lb/MMBtu (24-hr average) to confirm efficient combustion in the incinerator. With these permit restrictions, visible emissions are not expected. Compliance with this rule is expected.

LSFO Flare: Gas releases to this flare are minimized since it is equipped with a vapor recovery system to capture all normal releases and a portion of the emergency releases from PRDs. The Chevron refinery has been relatively effective at minimizing flaring events. As discussed later in the evaluation of District Rule 1118, SOx emissions from Chevron's flares during 2006 and 2007 were well below current and future Rule 1118 SOx performance targets. Under a recently completed project, the capacity of the LSFO VRS was increased by 6 mmscfd through replacement of the three existing vapor recovery compressors with larger compressors.

As discussed earlier, the potential for emergency releases from the new PRDs is low because they are only designed to open only in the event of a catastrophic fire. Even though the potential for flaring is not expected to increase significantly, all refinery flares do have some potential for exceedance of 20 percent opacity for a period of greater than 3 minutes during an extreme emergency if the load to the flare exceeds the smokeless capacity of the flare. As discussed in the 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)	
		SWS/SRU/TGTU / Incinerator	Entire Project (2)
CO	220	27.4	379
NOx	40	18.4	-235
PM10	30	7.5	117
SOx	60	59.4	202
VOC	30	21.2	203
Lead	3	0	0

(1) Increase in 30-day average maximum potential to emit
(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 facility wide emission increases for each of the criteria pollutants exceed the thresholds listed in subdivision (g). There will be more than one public notice since public notices will be issued for batches of applications as they are approved. Public notices have been published for the first two application batches. Permits have subsequently been issued for the applications included each of the first two public notices. The third public notice will include the following applications:

Equipment	Application No.
Sour Water Stripper Plant No. 68	467141
Sulfur Recovery Unit No. 73	470738
Tail Gas Treatment Unit No. 73	470739
TGTU Incinerator	480556
LSFO Flare	482505
LSFO VRS	482504
TGTU SOx Scrubber	498947
Sulfur Recovery Unit No. 10	499500
Sulfur Recovery Unit No. 20	499877
Sulfur Recovery Unit No. 70	499878

$$PM = \left(\frac{7.5 lbPM}{MMscfNG}\right)\left(\frac{scfNG}{1050 BTU}\right)\left(\frac{MMBtu}{8710 scffluegas}\right)\left(\frac{7000 grain}{lb}\right) = 0.006 \text{ grain/dscf}$$

As shown in the calculation section, the maximum flue gas flow for the incinerator is 20,100 dscfm. From Table 404(a) in Rule 404, the PM limit for an exhaust gas flow of 20,100 dscfm is 0.061 gr/dscf. The estimated PM concentration of 0.006 gr/dscf is well below this limit. Compliance with this rule is expected.

LSFO Flare: PM emissions from the normal operation of the LSFO flare is estimated using the District AER (and Rule 1118) emission factor (EF) of 7.5 lb/MMscf of natural gas combusted. An "F" factor of 8710 scf of flue gas per MMBtu per hour of natural gas combustion is believed to provide a reasonable estimate of the exhaust gas flow rate for the combustion of pilot and purge natural gas in the flare. The calculation of the PM concentration for the exhaust gas from normal operation of the flare is shown below.

$$PM = \left(\frac{7.5 lbPM}{MMscfNG}\right)\left(\frac{scfNG}{1050 BTU}\right)\left(\frac{MMBtu}{8710 scffluegas}\right)\left(\frac{7000 grain}{lb}\right) = 0.006 \text{ grain/dscf}$$

The estimation of the exhaust gas flow for the LSFO flare is shown below.

$$Iso \max FlareExhaustRate = \left(\frac{2180 scfNG}{hour}\right)\left(\frac{1050 Btu}{scgNG}\right)\left(\frac{8710 scffluegas}{MMBtu}\right)\left(\frac{hour}{60 \min}\right) = 330 \text{ dscfm}$$

From Table 404(a) in Rule 404, the PM limit for exhaust gas flows below 883 dscfm is 0.196 gr/dscf. Even at high levels of excess O2, the flue gas flow rate should be below 883 dscfm. The estimated PM concentration of 0.006 gr/dscf is well below the Rule 404 limit of 0.196 gr/dscf. Compliance with this rule is expected.

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 TGTU Incinerator or LSFO Flare. None of the sources covered under this evaluation are subject to the requirements of this rule.

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 permit units covered by this evaluation that will have CO emissions are the TGTU Incinerator and LSFO Flare.

process description section of this evaluation, the LSFO Flare is equipped with steam injection to provide smokeless combustion up to the smokeless capacity of the flare. This smokeless capacity varies depending on the properties of the gas being combusted. For releases up to the smokeless capacity of the flare, smoking will occur only during a short transitory period while the steam injection system adjusts to the load being sent to the flare. An increase of the smokeless capacity of these flares is not warranted since additional steam would have to be produced around the clock to cover visible flaring events that are relatively rare. Production of additional steam would cause an increase in criteria and toxic pollutants for steam that could not be utilized during normal operational periods when no flaring occurred.

Emergency situations such as a loss of power are covered by the "Breakdown Provisions" of Regulation 430. If the emergency qualifies as a "Breakdown" and Chevron complies with the requirements of 430(b)(3)(A), the smoking during an emergency will not be a violation of this rule.

Rule 402: Nuisance

SWS No. 68, SRU No. 73, and TGTU No. 73: All of these permit units process gas streams that contain H2S, which is an odorous sulfur compound that can have acute health affects. For safety reasons, the areas in these process units that handle high H2S streams will have alarm equipped ambient H2S monitors. These monitors minimize the nuisance potential of these process units. Chevron has not received any H2S related nuisance complaints over the last two year period. Compliance with this rule is expected.

TGTU Incinerator: As discussed above, the incinerator permit will be conditioned with limits on minimum temperature and stack gas H2S and CO concentrations to assure efficient combustion in the incinerator. Nuisance potential is minimal under normal operating conditions. Compliance with this rule is expected.

LSFO VRS and Flare: There is no record of nuisance complaints for the LSFO Flare over the last three year period. The flare is equipped with steam injection to minimize the nuisance potential of the flare. Due to the design of the emergency pressure relief systems in the new SWS and SRU, connection of the new PRDs to the VRS/flare is not expected to cause a significant increase in the nuisance potential.

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.

SWS, SRU, and TGTU: Emissions to the atmosphere will be in the form of liquid and gaseous leakage from fugitive components. No PM emissions are expected.

TGTU Incinerator: PM emissions from the normal operation of the TGTU Incinerator is estimated using the District AER emission factor (EF) of 7.5 lb/MMscf of natural gas combusted. An "F" factor of 8710 scf of flue gas per MMBtu per hour of natural gas combustion is used to provide a conservative estimate of PM emissions from the incinerator. This estimate is conservative because the TGTU tail gas will increase the amount of flue gas to decrease the concentration of PM in the flue gas. The calculation of the PM concentration for the exhaust gas from normal operation of the incinerator is shown below.

limit of this rule. Compliance with the requirements of this rule is expected during normal operation of these combustion devices.

Rule 468: Sulfur Recovery Units

This rule specifies that an SRU shall not exhaust or vent effluent that contains more than:

(a) 500 ppm of sulfur compounds expressed as sulfur dioxide, calculated on a dry basis averaged over a minimum of 15 consecutive minutes.

(b) 10 ppm of hydrogen sulfide averaged over a minimum of 15 consecutive minutes and calculated on a dry basis.

(c) 90 kilograms (198.5 pounds) per hour of sulfur compounds expressed as sulfur dioxide.

The SOx emission limits of 468(a) and 468(c) are subsumed by RECLAIM [Rule 2001(j)]. The H2S emission limit of 468(b) is applicable. An NSR BACT limit of 2.5 ppmv (0% O2, 24-hour average) will also be imposed on the TGTU Incinerator. The primary purpose of the TGTU Incinerator is the oxidization of H2S in the TGTU tail gas to SO2. Based on performance of other TGTU incinerators, the 1450°F temperature limit on the incinerator is expected to be adequate to ensure compliance with the 10 ppmv H2S emission limit. Compliance with this rule is expected.

Regulation IX - NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Subpart A – General control device requirements (40CFR60.18).

40CFR60.18 of Subpart A contains general requirements for control devices used to comply with applicable subparts of parts 60 and 61. The control device requirements of NSPS Subpart A include:

60.18(c)(1): "Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours."

As stated in 60.11(c), the "opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard". Chevron is required to meet the requirement for operation of the flare with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours at all times except startup, shutdown, or malfunction as defined in Subpart A. Compliance with this requirement is expected since the flare only combusts pilot and purge natural gas during normal operation and is equipped with a water seal and VRS. .

60.18(c)(2): "Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f)." (f)(2) states that "the presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame." Chevron utilizes a thermocouple (with an infrared detector as a backup) to monitor the

TGTU Incinerator: The permit for the TGTU Incinerator will be conditioned with a BACT CO limit 0.03 lb/MMBtu (24-hr average), which equates to a concentration of approximately 13 ppmv (0% O2) and a minimum temperature limit of 1450°F. This temperature limit is high enough to ensure adequate combustion of the low concentration of hydrocarbons in the tail gas to comply with both CO limits. Compliance with the CO limit of this rule is expected.

LSFO Flare: According to R407(b)(3), the provisions of this rule shall not apply to emissions from emergency venting due to equipment failure or process upset. During normal operation, all vent gases are captured by the VRS so only pilot and purge gas are being combusted in the flare. Compliance with the 2000 ppmv CO limit is expected during normal operation of these flares.

Sulfur Compound Limit:

The permit units covered by this evaluation that have the potential to emit sulfur compounds are the SWS, SRU, TGTU, TGTU Incinerator, and LSFO Flare.

SWS, SRU, and TGTU:
The final condensers, the SO2 absorbers, and the sulfur pits are each currently tagged with the 500 ppmv sulfur limit of this rule. The sulfur emissions in the process streams from this equipment are controlled in the TGTU. The sulfur compounds emitted from the TGTU are oxidized to SO2 in the TGTU incinerator. The SO2 emissions from the TGTU incinerator are regulated by the District RECLAIM Rule and are exempt from Rule 407 requirements. Only fugitive sulfur compound emissions from this equipment will be subject to Rule 407. It is expected that any fugitive leaks will be quickly identified since H2S and other reduced sulfur compounds are odorous. Compliance with the sulfur compound limit of this regulation is expected.

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

LSFO Flare: As discussed in more detail in the analysis of RECLAIM requirements, flares are exempt from RECLAIM. Therefore, the flare is subject to the sulfur compound limit of Rule 407 during normal operation of the flare. As discussed above, the provisions of this rule do not apply to emissions from the emergency venting from equipment failure or process upset. Compliance with the 500 ppmv sulfur compound limit is expected during normal operation of these flares, which includes the combustion of pilot and purge natural gas flows to the flare. These flares are only expected to be challenged with a significant amount of high sulfur vent gases during equipment malfunctions or process upsets. Compliance with this rule is expected.

Rule 409: Combustion Contaminants

This rule contains a 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). In Rule 102, combustion contaminants are defined as "are particulate matter discharged into the atmosphere from the burning of any kind of material containing carbon in a free or combined state".

As shown in the evaluation of Rule 404, the estimated PM emissions from the combustion of natural gas in the TGTU Incinerator and LSFO Flare is 0.006 gr/dscf, which is well below the

LSFO VRS will go to the LSFO Flare. Compliance with the requirements of this regulation is expected.

<u>Subpart Ja -- Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.</u>

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)

It is applicable to flares that were constructed, reconstructed, or modified after June 24, 2008.

LSFO Flare

As specified at §60.102a(h), the "combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from paragraph (g) of this section". The referenced paragraph (g) contains the emission limits for fuel gas combustion devices. Connection of new PRDs to the subject flare is not considered a modification of the flare since there is no increase in SOx emissions from the flare during normal operation. During normal operation, all vent gases from the new PRDs will be captured by the VRS. This flare is not subject to this NSPS.

Sulfur Recovery Unit Nos. 10, 20, 70 and 73

Sulfur recovery plants are affected facilities under this NSPS. A sulfur recovery plant is defined as "all process units which recover sulfur from $HS_2$and/or SO_2 at a petroleum refinery". It is further defined that "multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas". As discussed earlier, Chevron's three existing SRUs share a common acid gas distribution manifold. Thus the three existing SRUs meet the definition of a sulfur recovery plant in this regulation. The common acid gas manifold will be connected to the new SRU so the construction of the new SRU is considered to be a modification of the existing sulfur recovery plant. Therefore, the sulfur recovery plant will become an affected source that is subject to the requirements of this regulation. Each of the SRU systems in the Facility Permit will be tagged condition S13.12, which denotes that they are subject to this NSPS.

The requirements of this NSPS for SRPs with a capacity greater than 20 long tons per day (ltpd) are not significantly different than the requirements of NSPS Subpart J.

<u>Emission Limit</u>: This regulation contains the following emission limits at 60.102a(f)(1):

- SO2: 250 ppmv (dry, 0%O2) for SRUs with an oxidation system or reduction system followed by incineration.
- Reduced Sulfur Compounds: 300 ppmv (dry, 0% O2) and H2S: 10ppmv (dry, 0% O2) for SRUs with a reduction system that is not followed by incineration.

existence of a flame. Condition D12.14 for each of the flares requires that "operator shall install and maintain a(n) thermocouple or any other equivalent device to accurately indicate the presence of a flame at the pilot light. The operator shall also install and maintain a device to continuously record the parameter being measured." Chevron has the monitoring and recording systems in place to comply with the requirements of this section. Continued compliance is expected.

60.18(c)(4)(ii): Steam-assisted and non-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf). The net heating value of the gases that would be combusted in these flares is greater than 1000 btu/scf so an exit velocity of less than 400 ft/sec is required. As shown in the "Process Description" section of this evaluation, the exit velocity for the maximum estimated load to the flare is 229 ft/sec.

60.18(c)(6): Flares used to comply with this section shall be steam-assisted, air-assisted, or non-assisted. The LSFO Flare is steam assisted.

60.18(e): Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them. Compliance with this requirement is expected.

<u>Subpart J – Standards of Performance for Petroleum Refineries</u>

This NSPS is applicable to the following affected facilities in petroleum refineries:

- Fluid Catalytic Cracking Unit Catalyst Regenerators
- Fuel Gas Combustion Devices
- All Claus Sulfur Recovery Plants (SRPs)(except Claus Plants of 20 long tons per day (LTD) or less

LSFO Flare: The LSFO Flare meets the NSPS Subpart J definition of a fuel gas combustion device so it would be subject to this NSPS if it was constructed, reconstructed, or modified after June 11, 1973 but before May 14, 2007. The flare was not constructed, reconstructed, or modified within the specified time period but it did become subject to this NSPS under Consent Decree No. C 03-04650 CRB (CD), which was filed in U.S. District Court in San Francisco on October 16, 2003 and approved by a US District Court Judge on June 28, 2005. This Consent Decree is the result of a settlement between Chevron and EPA over alleged violations of the certain Clean Air Act and CERCLA/EPCRA provisions including the New Source Performance Standards. Under the terms of this CD, all of the flares at the Chevron Refinery, with the exception of the SMR and SNR Hydrogen Plant ground flares, will become subject to NSPS Subpart J according to the schedule specified in the CD. Under the schedule in the CD, the LSFO Flare became subject on December 31, 2008.

This regulation has a limit of 160 ppm H2S for any fuel gas combusted in the flares. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this standard. A process upset gas is defined as "any gas generated by a petroleum refinery process unit as a result of start-up, shutdown, upset, or malfunction. The system is designed such that any normal plant venting or blowdowns are handled by the combination of the flare water seal and LSFO VRS. It is expected that only emergency (upset or malfunction) venting that exceeds the capacity of the duration of excess emissions is less than 1 percent of the total operating time or the reporting period and the duration of the CMS downtime is less than 5 percent of the total operating time for the reporting period. If either of these thresholds is exceeded, both the summary report and the excess emissions report must be submitted. SO2 emissions are expected to be well below 250 ppmv. As noted earlier, the permit for the proposed SRU will be conditioned with an NSR limit of 12 ppmvd SO2 (0% O2). Based on Chevron's compliance history for other equipment that is subject to NSPS Subpart J, compliance with this requirement is expected.

TGTU Incinerator - The TGTU Incinerator will utilize commercial natural gas as a primary fuel. The only other gas that will be put into the incinerator is the tail gas from the TGTU. Neither of these gases is considered to be a fuel gas under this regulation. The incinerator is not subject to the requirements of this regulation as a fuel gas combustion device since it does not combust a fuel gas.

Subpart GGGa—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006

This NSPS is applicable to affected facilities in refineries that constructed, reconstructed or modified after November 7, 2006. The following are affected facilities under this subpart:

- Compressors
- The group of all the equipment within a process unit.

Equipment is defined as "each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service". From Subpart VVa (as referenced from GGGa), the definition of "*in VOC service*" is that "the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight".

Sour Water Stripper - The proposed sour water stripper will have some fugitive components that are in VOC service. However, it is not a process unit as defined in NSPS GGG. Note that the definition of process unit in the current version of NSPS GGG and GGGa has been stayed until further notice. Therefore, the definition in the previous version of NSPS GGG is utilized. Process unit is defined as "the 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". The sour water stripper is not a process unit because it does not produce an intermediate or final product. Therefore, it is not subject to the requirements of this regulation.

SRU, TGTU, and TGTU Incinerator – These permit units do not contain any VOC service fugitive components. Therefore, they are not subject to the requirements of this regulation.

40CFR60: Subpart QQQ: Standards of Performance for VOC Sources from Petroleum Refinery Wastewater Systems

This regulation is applicable to a facility located in petroleum refineries for which construction, modification, or reconstruction commenced after May 4, 1987. The following are separate affected facilities under this regulation:

The proposed SRU is equipped with a reduction type TGTU followed by incineration so it will be subject to the 250 ppmv SO2 limit. This regulation also has an equation for calculation of the emission limit for SRUs that utilize oxygen enrichment. Chevron's proposed SRU does not utilize oxygen enrichment.

As discussed in more detail in the evaluation of Regulations XIII and XX, the permit for the TGTU will be conditioned with a 12 ppmv (dry, 0% O2) SO2 limit. This NSR limit is based on current BACT for SRUs/TGTUs. Based on the advanced technology utilized in the proposed SRU/TGTU, compliance with both the 250 ppmv SO2 limit of NSPS Subpart Ja and the more stringent BACT limit is expected.

Other Requirements: Some of the pertinent additional requirements of this regulation are outlined below. These requirements are also essentially the same as those in NSPS Subpart J. Based on Chevron's compliance history for existing equipment that is subject to NSPS Subpart J, compliance with these requirements is expected.

Root Cause Analysis [§60.103a(b)] – Each owner or operator that operates a fuel gas combustion device or sulfur recovery plant subject to this subpart shall conduct a root cause analysis of any emission limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge to the atmosphere in excess of 227 kilograms per day (kg/day) (500 lb per day (lb/day)) of SO2.

Initial Performance Test [§60.104a(a)] - The owner or operator shall conduct a performance test to demonstrate initial compliance with the 250 ppmv (dry, 0%O2) emission limit according to the requirements of §60.8. According to 60.8(a), this initial test must be performed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility and at such other times as may be required by the Administrator. The permit to construct for the incinerator will also include a condition that specifies an SO2 source test to show compliance with the BACT SO2 emission limit. One source test can be performed to comply with both of these source test requirements. Based on Chevron's compliance history for other equipment that is subject to NSPS Subpart J, compliance with this requirement is expected.

Continuous Emission Monitoring System [§60.106a(a)(1)] – The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air. The CEMS shall be installed, operated, and maintained according to Performance Specification 2 of Appendix B to part 60. Performance evaluations shall be performed according to the requirements in §60.13(c) and Performance Specification 2 of Appendix B to part 60. Chevron will also be required to install an SO2 CEMS for compliance with the District's RECLAIM regulation.

Reporting [§60.106a(b)] - For the purpose of the reports required by §60.7(c), periods of excess emissions are defined as all 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 CEMS exceeds 250 ppmv (dry, 0%O2). The rolling 12-hour average is the arithmetic average of 12 contiguous 1-hour averages. 60.7(c) requires that "each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report and-or the summary report form to the administrator semiannually". According to 60.7(d), only the summary report must be submitted if the total 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).

<u>*Sour Water Stripper*</u> – Ammonia (NH_3) and hydrogen sulfide (H_2S) are major constituents of the various streams in the SWS. These pollutants are TACs under the District Rule 1401 but they are not included in the list of 189 HAPS that are regulated by the MACT standards including Subpart CC. As seen in the Rule 1401 calculations, some of the streams in this permit unit will also contain BTEX (benzene, ethyl benzene, toluene, xylenes), which are HAPs. However, none of the streams in this permit unit are expected to have a total HAP concentration of 5% or greater. Therefore, none of the fugitive components in this permit unit are expected to be subject to this regulation.

<u>*SRU, TGTU, and TGTU Incinerator*</u> – As seen in the Rule 1401 calculations, none of the streams in these permit units are expected to contain appreciable concentrations of HAPs. Therefore, none of the fugitive components in these permits will be subject to this regulation.

<u>*LSFO VRS and LSFO Flare*</u> – Both of these permit units have existing fugitive components that are subject to this regulation. The "fugitive emissions, miscellaneous" device, which represents the fugitive components in a permit unit, for each of these permit units is tagged with "HAP: 40CFR 63 Subpart CC, 5-25-2001" to denote that each permit unit contains some fugitive components that are subject to this regulation. As mentioned previously, no new fugitive components are being installed in this permit unit.

This regulation refers to the fugitive component monitoring requirements of NSPS Subpart VV and NESHAP Subpart H with exceptions that are specifically noted in the regulation. In general, the equipment leak inspection and monitoring requirements of District Rule 1173 are more stringent than this regulation but pertinent requirements of this regulation have been incorporated into Chevron's Inspection and Monitoring (I&M) Program for fugitive emissions. Continued compliance with the inspection, maintenance, and record keeping requirements of this rule is expected.

Applicability for Miscellaneous Process Vents: *Miscellaneous process vent* is defined as "a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit. Miscellaneous process vents include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere".

The definition of a *miscellaneous process vent* at 40CFR63.641 specifies a number of vent streams that are not considered to be *miscellaneous process vents*, which are subject to the requirements of this rule. Some of the streams that are included in this list of exempt streams are:

- Gaseous streams routed to a fuel gas system
- Relief valve discharges
- "Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring, and catalyst transfer operations.
- Sulfur plant vents

- An individual drain system (all process drains connected to the first common downstream junction box, together with their associated sewer lines and junction boxes, downstream to the receiving oil-water separator)
- An oil-water separator
- An aggregate facility (individual drain system together with ancillary downstream sewer lines and oil-water separators)

According to Chevron, there will be 78 new process drains installed in the SWS, SRU, TGTU and TGTU Incinerator permit units. These drains will be subject to this NSPS. According to Chevron, each of these drains, which feed to the existing unsegregated wastewater treatment system at the refinery, will be equipped with a water seal as required at 60.692-2(a)(1). Compliance with the requirements of this regulation is expected.

Regulation X - NATIONAL EMISSION STANDARD FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)

40CFR61: Subpart FF: National Emission Standard for Benzene Waste Operations

Chevron is subject to the control requirements of this regulation since the Total Annual Benzene (TAB) for the refinery is above the 10 Mg/yr threshold. This regulation contains standards for storage tanks, surface impoundments, containers, individual drain systems, oil-water separators, treatment processes, and closed vent systems/ control devices. The new process drains are the only new equipment being installed under this project, that are subject to the control requirements of this regulation.

61.346 Standards for Individual Drain Systems –

(a)(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.
(b)(1) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements: Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

Chevron has confirmed that the new drains will comply with the requirements of §61.346(b)(1), which specifies a drains must be equipped with water seal controls or a tightly sealed cap or plug. Compliance with the requirements of this regulation is expected.

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. This subpart took effect on August 18, 1998 and was last amended on April 25, 2001.

Applicability for Equipment Leaks: The equipment leak standards for existing sources as specified in 63.648 are applicable to fugitive components that are "in organic hazardous air quarterly reports using a code system developed by the District. For example, flaring due to equipment failure is assigned a District Relative Cause Code of 3.

Flare Inquiry Phone Service [1118(i)(1)] - Provide a 24 hour telephone service for access by the public for inquiries about flare events Chevron's 24 hour Community Hotline number is (310) 615-5342. This number is listed on the District's web site.

Notification of Unplanned Flare Events [1118(i)(2)] - Notify the Executive Officer by telephone within one hour of any unplanned flare event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or exceeding 500,000 standard cubic feet of flared vent gas. Compliance with this notification requirement is expected.

Notification of Planned Flare Events [1118(i)(4)] - Notify the District at least 24 hours prior to the start of a planned flare event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of combusted vent gas. These notifications are made through the District's Flare Event Notification web page. A record of all notifications can be accessed through the web page.

Quarterly Report [1118(i)(5)] - Submit a quarterly report in an electronic format approved by the District within 30 days after the end of each quarter. Chevron has submitted all required quarterly reports. Continued compliance with this requirement is expected.

Color Video Monitors [1118(g)(7)] - Monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare and flame at a rate of no less than one frame per minute. According to Chevron, the required cameras and recorders have been installed and are recording images at a rate of once per minute.

Flare Monitoring and Recording Plan [1118(g)(7)] - By June 30, 2006, submit a revised Flare Monitoring and Recording Plan, which shall include all information specified at 1118(f)(3) [1118(f)(1)(A)]. They must comply with the existing plan until a revised plan is approved. A facility must start monitoring and recording in accordance with the Revised Flare Monitoring and Recording Plan within 6 months after the plan is approved [1118(g)]. Chevron submitted this plan (AN 458606) on June 30, 2006. Chevron has also submitted two addendums to the plan.

The rule contains monitoring and recording requirements for flares at 1118(g)(3). The requirements for emergency and general service flares are summarized in the following table:

Operating Parameter	**Monitoring and Recording Requirement**	
	Effective until June 30, 2007	**Effective July 1, 2007**
Gas Flow	Measured and Recorded Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)	Measured and Recorded Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)
Gas Higher Heating Value	One Daily Representative Sample for a Flare Event and a Representative Sample for Each Sampling Flare Event; or Continuously Measured and Recorded	Continuously Measured and Recorded with a Higher Heating Value Analyzer

Based on this definition, none of the vent streams associated with this project is subject to this MACT standard. Vapor leakage from the new PRDs will be captured by the LSFO VRS, which is part of the refinery's fuel gas system. Other releases from the PRDs are exemption since they will only occur on a nonroutine basis as a result of a malfunction or emergency. The sulfur plant vent is exempt because it is covered by 40 CFR 63 Subpart UUU. The vapor stream from the accumulator (V-6820) in the new SWS is not considered a process vent since it is fed to the SRU, which is a process

Regulation XI: SOURCE SPECIFIC STANDARDS

Rule 1118: Emissions from Refinery Flares

Background

This rule was adopted on February 13, 1998 and subsequently amended on November 4, 2005. It applies to all gas flares used at petroleum refineries, sulfur recovery plants and hydrogen production plants. The LSFO Flare is subject to the requirements of this rule as an emergency service flare. The purpose of Rule 1118 as adopted in 1998 was to monitor and gather data on refinery flares for evaluation of the need of additional controls to minimize flaring events. The primary requirements of 1998 version were submission and approval of a monitoring plan [1118(c)(1)], monitoring of release events, and quarterly reporting of monitoring results. The remainder of this section contains an evaluation of the requirements of the current version of this rule.

Current Requirements

Flare Pilot [1118(c)(1)(A)] - Maintain a pilot flame present at all times a flare is operational. The LSFO Flare is equipped with a thermocouple to monitor the existence of the pilot light.

Annual Leak Survey [1118(c)(1)(C)] - Conduct an annual acoustical or temperature leak survey of all pressure relief devices connected directly to a flare and repair leaking pressure relief devices no later than the next turnaround. The survey shall be conducted no earlier than 90 days prior to the scheduled process unit turnaround. This requirement is not applicable since the PRDs for the subject LSFO VRS/Flare are not connected directly to the flare. The water seals prevent any PRD leakage from flowing to the flares.

Specific Cause Analysis [1118(c)(1)(D)] - Conduct a Specific Cause Analysis for any flare event, excluding planned shutdown, planned startup and turnarounds, with emissions exceeding either:

- o 100 pounds of VOC;
- o 500 pounds of sulfur dioxide;
- o 500,000 standard cubic feet of vent gas combusted.

This analysis must be submitted to the District within 30 days of the event unless an extension is granted [1118(i)(3)]. Compliance with this analysis and reporting requirement is expected.

Relative Cause Analysis [1118(c)(1)(E)] - Conduct an analysis and determine the relative cause of any other flare events where more than 5,000 standard cubic feet of vent gas are combusted. When it is not feasible to determine relative cause, state the reason why it was not feasible to make the determination. According to Chevron, reports of these analysis are contained in their

H2S Limit [1118(c)(5)] - Effective January 1, 2009, a refinery shall prevent the combustion in any flare of vent gas with a hydrogen sulfide concentration in excess of 160 ppm, averaged over three hours, excluding any vent gas resulting from an emergency, shutdown, startup, process upset or relief valve leakage. The LSFO flare is tagged with condition B61.11, which specifies this H2S limit. Compliance with this requirement is expected since the LSFO VRS has adequate capacity to collect and recover all vents gases during normal operation of the permit units that vent to the VRS/Flare.

Rule 1173: Control of Volatile Organic Compound Leaks and Releases from Components at 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.

According to 1173(l)(1)(C) and 1173(l)(1)(D) respectively, fugitive components that handle commercial natural gas and components that exclusively handle fluids with a VOC content of less than 10% are exempt from the requirements of this regulation. All of the fugitive components in the SRU, TGTU and TGTU Incinerator qualify for one of these exemptions. Some of the components in the new sour water stripper will be subject to the requirements of this rule. 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.

It is specified in 1173(h) that atmospheric PRDs located on process equipment must be equipped with electronic valve monitoring devices, which are capable of recording the duration of each release to the atmosphere and quantifying the amount of the compounds released. This requirement is not applicable since none of the existing process equipment covered in this evaluation contains an atmospheric PRD and no atmospheric PRDs will be installed in the proposed new process units.

Compliance with the requirements of this rule 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.

	with a Higher Heating Value Analyzer	
Total Sulfur Concentration	One Daily Representative Sample for a Flare Event and a Representative Sample for Each Sampling Flare Event; or Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer	Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer

As discussed in the "Compliance Record Review" section, all of the refineries currently have been granted a variance to the 1118(g)(3) requirement for continuous and semi-continuous monitoring of HHV and TSC, respectively. Under the increments of progress for Chevron's variance (Case No. 8313-43), Chevron must install and test the TSC and HHV analyzers on the LSFO flare by February 4, 2010.

Evaluation of Options for Reduction in Flaring [1118(c)(3)] - Submit an evaluation of options to reduce flaring during planned shutdowns, startups and turnarounds, including, but not limited to slower vessel depressurization and storing vent gases. Chevron has chosen to minimize flaring through slower vessel depressurization.

Flare Minimization [1118(c)(4)] - Operate all flares in such a manner that minimizes all flaring and that no vent gas is combusted except during emergencies, shutdowns, startups, turnarounds or essential operational needs. Chevron recently upgraded the LSFO VRS compressors to assist in compliance with this requirement. Connection of the new PRVs to the LSFO VRS is not expected to impact compliance with this requirement.

Performance Targets [1118(d)] - A refinery shall minimize flare SO2 emissions and meet the following performance targets for SO2 emissions. Compliance with the performance targets are determined at the end of each calendar year based on the facility's annual flare sulfur dioxide emissions normalized over the crude oil processing capacity in calendar year 2004.

- Calendar Years 2006 and 2007: 1.5 tons per million barrels of crude processing capacity
- Calendar Years 2008 and 2009: 1.0 tons per million barrels of crude processing capacity
- Calendar Years 2010 and 2011: 0.7 tons per million barrels of crude processing capacity
- Beginning in calendar year 2012: 0.5 tons per million barrels of crude processing capacity

If a refinery exceeds the performance targets for any calendar year, the owner or operator must:

- Submit a Flare Minimization Plan, and
- Pay the District mitigation fees. The rule includes a sliding fee schedule based on the relative amount of the exceedance. The rule includes a 60 day public review period for the Flare Minimization plan prior to approval of the plan.

Chevron has a total of 7 flares that are subject to this rule. Chevron's SO2 target for 2006 and 2007 was 142.7 tons per year based on a crude capacity of about 95 million barrels per year. Chevron's SO2 emissions for 2006 and 2007 were 25.3 tons and 9.5 tons, respectively. Chevrons SO2 target for 2008 and 2009 is about 114 tons per year. The proposed connection of new PRDs to the LSFO VRS and flare is not expected to impact Chevron's ability to achieve their SO2 performance targets.

(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.

The table below summarizes the permit units for which BACT must be evaluated due to an increase in the estimated maximum potential to emit (PTE) of CO, PM10, VOC, and ammonia that exceeds 1.0 lb/day. This table also shows the permit units that are subject to BACT for NOx and SOx under Rule 2005. As discussed in more detail in the evaluation of Reg. XX, BACT is triggered for NOx and SOx 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".

Permit Unit	Source	Pollutant	Uncontrolled Increase in Max. PTE (lb/day)
Sour Water Stripper (Process 12, System 28 – new)	Fugitive Components	VOC	3.52
Sulfur Recovery Unit No. 73 (Process 13, System 10 – new)	Fugitive Components	VOC	0.66
Tail Gas Treatment Unit No. 73 (Process 13, System 11 – new)	Fugitive Components	VOC	10.0
Sulfur Recovery Unit No. 73 (Process 13, System 10 – new)	Process Vent	SO2	59.4
TGTU Incinerator (Process 13, System 12 – new)	Combustion	CO NOx PM10 VOC	27.4 18.4 7.5 7.0

Since control of CO and VOC emissions from an incinerator can impact NOx emissions, the incinerator BACT determination for CO, NOX, PM10 and VOC will be integrated together. The incinerator BACT determination for CO, NOX, PM10 and VOC is contained in the Regulation XX (RECLAIM) evaluation that is contained later in this document. The following discussion is of BACT for VOC fugitive components only.

The VOC service fugitive components in the new SWS, SRU and TGTU are subject to BACT since the increase in VOC emissions is greater than 1.0 lb/day. A summary of BACT for VOC service fugitive components follows:

*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. Since gas flares are exempt from the requirements of RECLAIM, the NOx and SOx requirements of Reg. XIII are applicable. For the subject applications, an evaluation must be performed for PM10, VOC, and ammonia. For CO, sources are subject to only the BACT requirement of this regulation.

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:

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.

As discussed in the calculation section, the only criteria pollutant emission increases for the proposed SWS, SRU, and TGTU permit units are VOC emission increases due to the installation of new fugitive components and SOx emissions from the acid gas. It is specified in Appendix A of this rule that modeling is not required for VOC or SOx. Modeling is not required for any of these permit units.

The TGTU incinerator has CO, PM10, and NOx emissions. NOx modeling is discussed in the evaluation of Rule 2005. Modeling for CO and PM10 must be performed according to the procedures in Appendix A to Rule 1303 or other analysis approved by the Executive Officer or designee. 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.

The permitted capacity of the incinerator is 41.9 MMBtu/hr of natural gas Table A-1 in Appendix A of Rule 1303 is specified to be for noncombustion sources and for combustion sources less than 40 Million BTUs per hour. The maximum allowable CO and PM10 emissions for a combustion source with a capacity of 40 MMBtu/hr is 72.1 lb/hr and 7.9 lb/hr, respectively. The estimated maximum PTE emission of CO and PM10 for the TGTU Incinerator is 1.13 lb/hr and 0.31 lb/hr, respectively. Although the heat input of the TGTU incinerator is slightly above the largest capacity listed in this table, the CO and PM10 emissions of the incinerator are well below the maximum allowed CO and PM10 emissions for a 40 MMBtu/hr combustion source. Therefore, the incinerator passes the screening analysis.

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. Per District policy, Offsets are required for any increase in emissions that exceeds 0.5 lb per day on a maximum daily basis. It is also District policy that offsets are calculated on a project basis.

PM10 Emission Offsets – The only new PM10 emissions for this project are the 7.5 lb/day from the TGTU Incinerator. 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 PM10 ERCs required for the TGTU Incinerator are 7.5 x 1.2 = 9.0 lb/day. Chevron currently has sufficient VOC ERC's to cover this 9 lb/day of offsets.

VOC Emission Offsets - As seen in the table below, the total VOC emission increase for the project is 21.2 lb/day (30-day average). Total VOC ERCs required for the project are 21.2 x 1.2 = 25.4 lb/day, which rounds down to 25 lb/day. Chevron currently has sufficient VOC ERC's to cover this 25 lb/day of offsets. The VOC offset requirements will be attributed to the subject permit units in the District NSR database as shown in the table.

- *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 subject permit units following the proposed modifications. It is also specified that Chevron shall not startup the equipment prior to the Districts approval for the use of all non-leakless valves. Condition S31.20 will be tagged to SWS No. 68, SRU No. 73, and TGTU No. 73, even though it appears that all of the valves in the SRU and TGTU will be exempt from the requirement to be leakless.

- *Relief Valves*: BACT for emergency pressure relief valves (PRVs) is connection to a closed vent system. All new PRDs installed under this project will be connected to the LSFO VRS.

- *Process Drain*: BACT for new process drains is installation of p-trap water seals or seal pots and inclusion in an approved I&M program. Chevron has specified that all of the new process drains installed in the SWS, SRU, and TGTU will be equipped with p-trap type water seal controls.

- *Pumps*: Pumps in light liquid service will be equipped with double or tandem seals vented to a closed system and included in an approved I&M program. Pumps in heavy liquid service will include single mechanical seals and included in an approved I&M program.

- *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. There will be no new compressors installed for this project.

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

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 and an addendum is being prepared for the proposed SOx scrubber. 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 Ms. 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 Appendix K.

(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.

The Tail Gas Incinerator is the only permit unit cover by this evaluation that emits PM10. As seen in the Calculation Section, the estimated maximum potential PM10 emissions for the incinerator is 1.4 ton/yr. A modeling analysis for plume visibility is not required since the PM10 emissions are below 15 ton/year. The subject requirement for NOx has been subsumed by RECLAIM.

(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

<u>Rule 1401: New Source Review of Carcinogenic Air Contaminants</u>

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.

Summary of VOC Offset Requirements

Application Number	Permit Unit	Source	Emission Increase (lb/day)	Offsets (lb/day)
467141	SWS No. 68	Fugitive Components	3.52	4
470738	SRU No. 73	Fugitive Components	0.66	1
470739	TGTU No. 73	Fugitive Components	10.0	12
480558	TGTU Incinerator	Combustion	7.0	8
		Total	**21.2**	**25.4 = 25**

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 so ERCs generated in Zone 1 will be used to offset the emission increases.

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.

Sulfur Recovery Unit No. 73: Rule 1401 Tier 1 Screening Analysis

Components	Project Emissions		Screening Threshold		Pollutant Screening Index	
	lb/yr	lb/hr	Cancer/ Chronic lb/yr	Acute lb/hr	Cancer/ Chronic	Acute
Ammonia	377	0.0430	51700	8.57	0.007292	0.005022
Carbon Disulfide	0.8	0.0001	207000	18.9	0.000004	0.000005
Hexane	2.3	0.0003	1810000	na.	0.000001	na.
Hydrogen Cyanide	0.1	0.00001	2330	0.91	0.000047	0.000014
Hydrogen Sulfide	1285	0.1467	2580	0.112	0.498062	1.309728
				Total	**0.51**	**1.31**
				Significant Threshold	**1**	**1**
				Result	**Pass**	**Fail**

Tail Gas Treatment Unit No. 73: Rule 1401 Tier 1 Screening Analysis

Components	Project Emissions		Screening Threshold		Pollutant Screening Index	
	lb/yr	lb/hr	Cancer/ Chronic lb/yr	Acute lb/hr	Cancer/ Chronic	Acute
Ammonia	23	0.0026	51700	8.57	0.000445	0.000306
Carbon Disulfide	0.0	0.0000	207000	18.9	0.000000	0.000000
Hydrogen Sulfide	477	0.0545	2580	0.112	0.184884	0.486179
				Total	**0.19**	**0.49**
				Significant Threshold	**1**	**1**
				Result	**Pass**	**Pass**

As seen in the tables, the SWS and TGTU both passed the cancer/chronic and acute screening. No additional analysis is required for these permit units. The SRU passed the cancer/chronic screening but failed the acute screening due primarily to the fugitive H2S emissions from the piping for the H2S and ammonia acid gas feed to the SRU. No additional analysis is required for cancer/chronic risk. A Tier 2 analysis must be performed for acute risk. For this analysis, a conservative distance of 700 meters was used for the nearest commercial and residential receptor. Since the TAC emissions are from fugitive components, the SRU is modeled as a volume source. The nearest meteorological monitoring station to the refinery is at King Harbor, which is located near the coast south of El Segundo. The Tier 2 screening risk assessment is shown in Appendix L. The SRU passes the Tier 2 assessment since the acute hazard indexes for residential and commercial receptors are both 0.05, which is well below the threshold of 1.

TGTU Incinerator - The TGTU incinerator fails a Tier 1 screening analysis for both cancer/chronic and acute risk. Therefore, a Tier 2 screening risk assessment must be performed.

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. As discussed in the calculation section, an HRA must be performed for the following permit units, which have an increase in the estimated emission of one or more Rule 1401 TACs due to the proposed modifications to the permit unit.

- Sour Water Stripper (Process 12, System 28)
- Sulfur Recovery Unit (Process 13, System 10)
- Tail Gas Treatment Unit (Process 13, System 11)
- Tail Gas Incinerator (Process 13, System 12)

As discussed in the calculation section, all TAC emissions for the first three permit units are from fugitive components that are being installed. TAC emissions for the Tail Gas Incinerator are the result of combustion of the natural gas and combustible constituents in the SRU tail gas and residual TACs from the tail gas stream.

SWS, SRU and TGTU - As seen in Appendix J, the SWS, SRU, and TGTU are all centrally located in the refinery. The distance to the nearest refinery boundary is more the 700 meters. A Tier 1 screening analysis was performed. A Tier 1 analysis utilizes the most conservative receptor distance irregardless of whether the receptor is commercial or residential. A receptor distance of 100 meters was used for the Tier I analysis. The Tier 1 screening analysis for the SWS, SRU, and TGTU are shown in the following three tables.

Sour Water Stripper: Rule 1401 Tier 1 Screening Analysis

Toxic Air Contaminant	Project Emissions		Screening Threshold		Pollutant Screening Index	
	lb/yr	lb/hr	Cancer/ Chronic lb/yr	Acute lb/hr	Cancer/ Chronic	Acute
Ammonia	393	0.0449	51700	8.57	0.007602	0.005235
Benzene	5.1	0.0006	8.92	3.96	0.571749	0.000147
Ethylbenzene	3.9	0.0004	517000	NA	0.000008	NA
Hydrogen Sulfide	565	0.0645	2580	0.112	0.218992	0.575872
Toluene	16.7	0.0019	77500	99.1	0.000215	0.000019
Xylenes	18.6	0.0021	181000	58.9	0.000103	0.000036
				Total	**0.80**	**0.58**
				Significance Threshold	**1**	**1**
				Result	**Pass**	**Pass**

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. Additionally, this regulation contains "significant emission increase" thresholds for other unclassified pollutants for which there is not a NAAQS. The "significant emission increase" thresholds, as contained at District Rule 1702(s) and 40 CFR 52.21, are shown in the following table. Note that there are some differences in the list at Rule 1702(s) versus the list at 40CFR52.21(b)(23).

Pollutant	"Significant Emission Increase" Threshold (ton/yr)
Carbon Monoxide	100
Sulfur Dioxide	40
Nitrogen Oxides	40
Particulate Matter	25
PM10 (1)	15
PM2.5 (3)	10 tpy of direct $PM_{2.5}$emissions; 40 tpy of SO2; 40 tpy of NOx unless demonstrated not to be a $PM_{2.5}$ precursor under 40CFR52.21(b)(50).
VOC (1)	40
Ozone (1)(3)	40 tpy of VOC or NOx
Lead Compounds	0.6
Asbestos (2)	0.007
Beryllium (2)	0.0004
Mercury (2)	0.1
Vinyl Chloride (2)	1.0
Fluorides	3.0
Sulfuric Acid Mist	7.0
Hydrogen Sulfide (H2S)	10
Total Reduced Sulfur (TRS)(incl. H2S)	10
Reduced Sulfur Compounds (RSC)(incl. H2S)	10

1. Non-attainment pollutant. No evaluation required.
2. Pollutant not included at 40CFR52.21(b)(23).
3. Pollutant not included at 1702(s).

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

Since the TGTU incinerator is located very near the SRU, a nearest commercial and residential receptor distance of 700 meters is used in the assessment. The incinerator stack height is 150 feet. The Tier 2 screening risk assessment is shown in Appendix L. As seen in the table below, the new TGTU incinerator passes the Tier 2 screening risk assessment.

TGTU Incinerator: Summary Results of Tier 2 Screening Risk Assessment

Receptor	MICR	Acute Hazard Index	Chronic Hazard Index
Residential	8.26×10^{-8}	9.80×10^{-2}	1.60×10^{-2}
Commercial	8.51×10^{-9}	9.80×10^{-2}	1.60×10^{-2}

Since the new SWS, SRU, TGTU, and TGTU incinerator each pass either a Tier 1 or Tier 2 screening risk assessment, each complies with the requirements of this rule.

Project Basis: 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

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 SRU, TGTU, and TGTU Incinerator are new sources, there is an increase in both NOx and SOx emissions on an hourly maximum and annual basis. As seen in the Calculation Section, the NOx and SOx emissions are estimated to be 0.76 lb/hr (6640 lb/yr) and 4.07 lb/hr (35560 lb/yr), 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.

The SRU is subject to BACT for SOx and the TGTU Incinerator is subject to BACT for NOx. As specified in the Regulation XIII evaluation above, the TGTU Incinerator BACT determination in this section includes BACT for CO, NOx, PM10 and VOC.

SOx BACT for Sulfur Recovery Unit – As seen in Appendix M, Chevron performed an SRU BACT determination for SO2. In their SRU BACT determination, Chevron utilizes a "top-down" BACT analysis approach that is based on EPA guidance. The steps utilized in this "top down" approach are:

1. Identify available control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining technologies by air pollution control efficiency.
4. Evaluate remaining technologies by environmental, energy, and economic impacts.
5. Select BACT (the most efficient technology that cannot be rejected for environmental, energy, or economic reasons is BACT).

The "top-down" BACT analysis approach used by Chevron was originally developed for determination of BACT under PSD provisions of the CAA. This "Federal" BACT takes into account energy, environmental, and economic impacts in determining if an emission limit is achievable for a particular source type. The District's major source BACT, which is more akin to LAER, does not include consideration of energy, environmental, and economic impacts.

BACT is defined in District Rule 2000, as 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 Environmental Protection Agency (EPA) for such category or class of source; or

promulgated in 40 CFR 52.21 (NSR Reform) but not set forth in AQMD Regulation XVII."

The PRO Project must be evaluated under PSD since Chevron is proposing to construct the TGTU Incinerator and Cogeneration Unit, which both emit CO, NOx, and SOx emissions. EPA performed the PSD evaluation since Chevron is utilizing 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). Under this procedure, actual (historical) emissions are defined as the average emission rate, in tons per year, of emissions during any consecutive 24-month period within the 10 year period preceding project construction. A different 24-month period can be utilized for each pollutant.

EPA's PSD non-applicability determination is contained in Appendix N of this evaluation. As stated in the September 8th letter from Gerardo Rios of EPA to Neal Troung of Chevron, EPA has concluded "that the PRO Project will not result in a significant emissions increase and therefore will not result in a PSD major modification". Therefore, the project is not subject to PSD permitting requirements. Note that EPA also concurred with Chevron's assertion that the proposed Cogen D is not considered to be part of the PRO Project under PSD. Chevron asserts that the "two projects should be evaluated separately for PSD applicability because they are neither technically not economically dependent on one another. Each can technically operate without the other, and both are economically viable as stand alone projects."

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 TGTU Incinerator will be subject to this regulation but the LSFO Flare is exempt from the requirements of this regulation. The gas flare exemption is contained at Rule 2011(i) and 2012(k). The definition of a gas flare, as contained in 2011 Attachment E and 2012 Attachment F is "a combustion equipment used to prevent unsafe operating pressures in process units during shutdowns and startups and to handle miscellaneous hydrocarbon leaks and process upsets". The LSFO Flare qualifies for this exemption.

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

- SNEA-Haldor Topsoe Dry Contact Catalytic Oxidation
- Maxisulf Davy-McKee International
- Townsend
- Alberta Sulphur Research (ASR) Sulfoxide
- United States Bureau of Mines (USBM) Citrate
- Ammonium Thiosulfate (ATS) Process
- Union Carbide Acid Gas (UCAP)
- Lurgi Lucas
- Stauffer Aquaclaus
- Saarberg-Holter
- Pritchard CLEANAIR
- Trentham Trencor-M

Chevrons elimination of these TGTUs from consideration due primarily to their lack of commercialization is acceptable and reasonable. SRUs are complex refinery operations that must safely and reliably process acid gas with high H2S and NH3 concentrations. Reliability of the SRU/TGTU is critical in minimizing overall SO2 and H2S emissions from the processing of these acid gas streams. For this reason, acceptance of a non-commercialized TGTU as BACT for SRU SOx is not believed to be prudent.

3. Rank remaining technologies by air pollution control efficiency.

Chevron's control efficiency ranking is shown in the table below. Chevron's list of technologically feasible technologies includes all of the major competing technologies. Due to limited emission data, it is difficult to accurately rank many of these SRU/TGTU technologies. The control efficiency of each of these TGTU types can vary widely depending on the exact configuration and operation of the SRU/TGTU. The efficiency is also dependent on the solvent, catalyst, etc. The options are numerous. Claimed efficiencies also vary widely depending on the source of the information. Chevron ranked their proposed SCOT type TGTU as having the best sulfur recovery efficiency. Based on available emission data and information, it appears that other technologies at the top of their list can achieve equivalent efficiency with proper design and operation. However, no SRU or SRU/TGTU with superior long term sulfur recovery and SOx control performance has been identified. It is noted that there is significantly more SOx emission and sulfur recovery performance data available for SCOT units than other competing technologies due to the length and breadth of their use in the refining industry relative to other TGTU technologies.

Tail Gas Treating Technology	Recovery Performance and/or SO_2 in Stack
SCOT	99.97% (50 ppmvd (0% O_2))
Wellman Lord	99.95%
Euroclaus	99.95%
Clauspol	99.95%
Cansolv	100 ppmv
Superclaus	99.92%

(3) is any other emission limitation or control technique, including process and equipment changes of basic or control equipment which is technologically feasible for such class or category of source or for a specific source, and cost-effective as compared to AQMP measures or adopted District rules.

It is also specified that BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate (LAER) as defined in the federal Clean Air Act (CAA) Section 171(3) [42 U.S.C. Section 7501(3)].

The following BACT analysis utilizes, critiques, and enhances Chevron's BACT determination. Step 4 of Chevron's "top-down" approach is eliminated.

1. Identify available control technologies.

The proposed SRU, which is based on a modified Claus process, is the standard of the refining industry. In their BACT determination, Chevron identified and evaluated thirty-two separate TGTUs for processing of the tail gas from a modified Claus process. Some of the identified TGTUs may be more accurately identified as modifications or extensions of the Claus process. However, this distinction between TGTU and Claus process modification/extension has no impact on this BACT analysis. Based on my review of SRU/TGTU technologies, Chevron's list of thirty-two TGTUs is representative of the available TGTU technologies. There are numerous variations to the listed technologies and various proprietary solvents that can be used in some of the listed TGTUs but no significant technologies appear to be missing from Chevron's list of available TGTU technologies.

The District also requested that Chevron evaluate the feasibility of installing add-on SOx control equipment downstream of a TGTU. In their determination, Chevron refers to these downstream SOx controls as "tail gas polishing". The following "two tail gas polishing" technologies are evaluated in Chevron's determination: caustic scrubber and Emerachem SCONOx Technology. While there are a variety of caustic scrubber designs that can potentially be utilized to control SOx emissions from a TGTU, Chevron's determination is based on the MECS Dynawave scrubber.

In a separate effort, the District's rule development group is also evaluating SRU SOx control technologies. As required by the Clean Air Act, the District is currently performing a Best Available Retrofit Control Technology (BARCT) reassessment for SOx under the District's RECLAIM regulation. The reassessment includes BARCT for SRU/TGTUs. Part II of the District's Staff Report for the RECLAIM SOx BARCT reassessment includes a discussion of the potential for installation of each of the following SOx scrubbers downstream of existing TGTUs: BELCO Labsorb and Cansolv regenerative type scrubbers and Tri-Mer Cloud Chamber type non-regenerative scrubber. These scrubbers, which are not included in Chevron's BACT determination, also warrant consideration.

2. Eliminate technically infeasible options.

Chevron eliminates the following technologies because they have seen limited use due to technical or economic issues:

- Shell Flue Gas Desulfurization
- Westvaco

H2S and NH3 concentrations. SCOT type TGTUs have been widely accepted and used in the refining industry for over three decades. While the existing TGTUs at the El Segundo Refinery are Wellman Lord Units, Chevron has installed eight SCOT units at other Chevron refineries over the last decade. Therefore, they have extensive corporate experience with these TGTUs.

Worley Parson's, the SRU/TGTU designer and contractor, guarantees an SO2 concentration of 20 ppmv (0% O2, wet, 24-hr avg.) in the incinerator exhaust at the beginning of the SRU/TGTU run. They guarantee an SO2 concentration of 50 ppmv (O% O2, dry, 24-hr avg.) after 5 years of operation. Based on an SO2 concentration of 50 ppmvd at 0% O2, the total sulfur recovery efficiency of the SRU and TGTU combined is 99.97% when processing sour water and amine acid gas and 99.98% when processing only amine acid gas. According to Worley Parson's, the reduction in efficiency of the TGTU over the 5 year run between process turnarounds is caused by degradation in the effectiveness of the hydrogenation (Co-Mo) catalyst due to oxidation, blockage of sites by pipe scale/debris, and channeling of process gas through the catalyst. Concentrations of COS increase in the hydrogenation reactor exhaust as the efficiency of the catalyst degrades. MDEA does not effectively absorb COS.

Worley Parsons guarantee of 50 ppmv (O% O2, dry, 24-hr avg.) at the end of the 5-yr catalyst run is equal to the lowest existing BACT SO2 limit on an SRU/TGTU. An SRU with a SCOT TGTU at the Shell Refinery in Martinez California is currently subject to this limit and the permit for two SRUs with SCOT TGTU at the proposed Arizona Clean Fuels Refinery is conditioned with this 50 ppmv limit. There is not currently a lower SRU SOx limit in any EPA approved SIPs.

The SRU BACT determination is not complete without evaluation of the potential transfer of "tail gas polishing" technologies for control of SO2 from the SCOT TGTU. There are not currently any SRUs that are equipped with a SOx Scrubber or other SOx control device downstream of the TGTU incinerator but this exhaust stream is amenable to further SOx control. Chevron, along with Worley Parson's, John Zink, and MECS, have determined that it is feasible to utilize an MECS Dynawave caustic scrubber for removal of additional SO2 from the TGTU incinerator exhaust stream. Dynawave scrubbers are currently being utilized at three Sinclair Refineries as primary tail gas SOx treatment in lieu of a TGTU. According to Sinclair personnel, the Dynawave scrubbers have not had any recurring operational or maintenance problems.

The SCOSOx process has more complex operational requirements than scrubbers and the process has not been applied in an application similar to the subject application. To date, SCOSOx has only been applied upstream of SCONOx to control trace SOx quantities in natural gas combustion exhaust. SCOSOx is also subject to more frequent maintenance and higher downtime requirements than scrubbers. In the judgment of this engineer, SCOSOx is not currently a viable candidate for transfer into a critical refinery operation such as an SRU.

As stated above, MECS has guaranteed that the maximum SO2 concentration in the exhaust gas from the proposed Dynawave scrubber will not exceed 12 ppmvd at 0% O2 on a 72-hr average basis. This SO2 level is 76% lower than the lowest existing BACT SO2 limit of 50 ppmv. The difference in averaging period (24-hr vs. 72-hr) accounts for some of this reduction. The proposed TGTU/ SO2 Scrubber has the potential to achieve SO2 emissions significantly below 12 ppmvd over long averaging periods. For shorter averaging periods, Chevron argues that compliance with a sub 12 ppmv SO2 emission limit unrealistically requires continual optimum operation of the Claus Unit, SCOT Unit, incinerator, and caustic scrubber and near instantaneous

Beavon/Stretford	99.9%
Direct LO-CAT	99.9%
Indirect LO-CAT	99.9%
Chiyoda Thoroughbred 101	500 ppmv
PROClaus	99.5%
MCRC	99%
Beavon	99 to 99.9%
Lurgi Sulfreen	98.5 to 99%
BSR Selectox	98.5 to 99.5%
Amoco CBA	98 to 99.3%
IFP	97.85%

Chevron also evaluated the potential of adding a "tail gas polishing" device downstream of a SCOT type TGTU. The stack gas SO2 concentrations shown in the following table are based on Vendor guarantees or "performance estimates" provided to Chevron.

Tail Gas Polishing Technology	SO_2 in Stack
$SCOSO_x$	10 ppmvd, 0% O_2
Caustic Scrubber (MECS Dynawave)	10 ppmvd, as measured (1)

(1) Equivalent to 12 ppmvd at 0% O2

Chevron did not evaluate other scrubbers such as the BELCO, Cansolv and Tri-Mer SOx scrubbers with the same veracity as the MECS scrubber but it appears there are no known technological impediments to the use of these scrubbers in this application and that these scrubbers are expected to provide a similar level of SO2 control to the proposed MECS Dynawave scrubber.

4. Select BACT

Chevron proposes the following BACT:

- Modified Claus SRU,
- Modified SCOT type TGTU using a highly H2S selective proprietary MDEA solvent,
- TGTU Incinerator with low NOx burner, and
- MECS Dynawave non-regenerative caustic scrubber.

Based on an emission guarantee from MECS, Chevron proposes a BACT SO2 limit of 12 ppmvd (0% O2, 72-hr average).

The SRU BACT determination is complicated by the large number of SRU/TGTU technologies, configurations, catalysts, solvents, etc. and by the limited amount of SO2 emissions data available to evaluate many of these technologies on a long term basis. As mentioned above, overall reliability of the entire system must also be taken into account because an SRU/TGTU is a complex refinery process operation that must safely and reliably process acid gas with high

Facility	Year	Limit	Control Technique	Source
Refinery (TX-0478)		lb/MMBtu)(1)(2)		
ConocoPhillips Ferndale Washington Refinery	2004	42.2 ppmvd @ 7%O2 and 2.3 lb/hr (0.067 lb/MMBtu)(1)	Low-NOx burner	RBLC
Murphy Oil Wisconsin Refinery	2004	0.05 lb/MMBtu	Low-NOx burner	PSD Permit

(1) Calculated based on lb/hr limit and incinerator capacity.

(2) Appears that this incinerator operates in standby mode.

There have been no installations of downstream NOx controls such as SCR or SCONOx on TGTU incinerators. The proposed TGTU Incinerator design includes a waste heat boiler that will lower exhaust gas temperatures to about 500°F followed by a heat exchanger to further reduce exhaust gases to about 300°F to facilitate proper operation of the SOx Scrubber. This design does not facilitate the installation of either of these temperature dependent downstream NOx controls.

The NOx limit proposed by Chevron is lower than any limits identified on existing TGTU incinerator permits. The proposed ultra low NOx burner and NOx limit of 0.02 lb/mmbtu is considered BACT for NOx. The incinerator permit will also require a NOx CEMS for continuous compliance with the NOx limit.

CO and VOC BACT – The combustion of natural gas in the thermal oxidizer will produce CO and VOC emissions. The COEN/Todd RMB burner proposed by Chevron is designed to minimize NOx, CO, and VOC emissions. The incinerator is also designed to reduce H2S emissions to 2.5 ppmv. The permit for the thermal oxidizer is conditioned with a CO emission limit of 0.03 lb/mmbtu of natural gas combusted. The table below shows the lowest CO limits identified for recently issued permits for TGTU incinerators.

TGTU Incinerator: CO BACT Review

Facility	Year	Limit	Control Technique	Source
Valero St. Charles Louisiana Refinery	2007	4.2 lb/hr (0.084 lb/MMBtu)(1)	Engineering design and good combustion practice	RBLC
Marathon Petroleum Garyville Louisiana Refinery	2006	0.04 lb/MMBtu	Engineering design and good combustion practice	RBLC
Sunoco Toledo Ohio Refinery	2006	0.58 lb/hr (0.082 lb/MMBtu) (1)	Engineering design and good combustion practice	RBLC

response of these units to changes in acid gas load and H2S/NH3 concentrations. The District concurs that the subject SRU/TGTU is a complex SOx control application that is subject to higher short-term variation in SO2 emissions than more standard SOx control applications.

The higher SO2 emissions variability causes higher uncertainty in the determination of a short-averaging period SO2 emission limit that the SRU can comply with on a continual basis. Due to the high SO2 emissions variability, it is judged that continuous compliance with a short-averaging period SO2 emission limit that is significantly less than the proposed 12 ppmvd could be problematic. The SRU permit will be conditioned with a BACT SO2 concentration limit of 12 ppmvd (0% O2, 72-hr avg.). To assure that the SOx scrubber is achieving optimum SO2 control efficiency, the scrubber permit will be conditioned with lower limits for caustic flow rate and pH.

NOx, CO, VOC, and PM10 BACT for TGTU Incinerator - This section contains an evaluation of BACT for NOx, CO, VOC, and PM10 emissions for the proposed TGTU Incinerator. This evaluation included a comprehensive review of pertinent databases and websites including:

- SCAQMD BACT Guidelines - Parts B,C,D;
- BAAQMD BACT Guidelines;
- BAAQMD Title V - Shell, Valero, Tesoro, Chevron, ConocoPhillips;
- CARB BACT Clearinghouse;
- San Diego County AQMD;
- San Joaquin Valley Air District
- Texas BACT;
- US/EPA BACT/LAER Clearinghouse

NOx BACT – The combustion of natural gas in the incinerator will produce emissions of NOx. Chevron is proposing to install an ultra low NOx burner to minimize NOx emissions. The incinerator permit will be conditioned with a NOx limit of 0.02 lb/mmbtu of natural gas combusted. The table below shows the lowest NOx limits found for recently issued permits for TGTU incinerators.

TGTU Incinerator: NOx BACT Review

Facility	Year	Limit	Control Technique	Source
Valero St. Charles Louisiana Refinery	2007	3.25 lb/hr (0.065 lb/MMBtu)(1)	Low-NOx burner	RBLC
Marathon Petroleum Garyville Louisiana Refinery	2006	0.20 lb/MMBtu	Low-NOx burner	RBLC
Sunoco Toledo Ohio Refinery	2006	0.28 lb/hr (0.04 lb/MMBtu)(1)	Low-NOx burner	RBLC
Proposed Arizona Clean Fuels Refinery	2005	0.06 lb/MMBtu	Low-NOx burner	RBLC
Citgo Corpus Christi Texas	2005	3.5 lb/hr (0.035	Low-NOx burner	RBLC

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. From the APEP Report for the 2006-2007 RECLAIM Year, Chevron used 884 tons of NOx RTCs and 345 tons of SOx RTCs. Note that the Chevron Refinery has had progressively lower year-to-year NOx and SOx emissions over the past couple of years. The first full year of operation for the incinerator is expected to be 2010. Chevron's NOx and SOx RTC allocations for 2010 are 864 tons and 445 tons, respectively. The maximum PTE for NOx and SOx from the incinerator is 3.3 tons and 17.8 tons, respectively. Adding these emission increases to the 2006-2007 emissions yields annual estimated NOx and SOx emissions of 887 tons and 361 tons, respectively.

The projected SOx emissions for 2010 are 84 tons less than Chevron's RTC allocations for that year. If only the 3 ton increase in the NOx emissions due to the incinerator is taken into account, the projected NOx emissions for 2010 exceed Chevron's RTC allocations for that year by 23 tons. However, Chevron recently completed installation of an SCR on the FCCU regenerator exhaust gas stream that is expected to decrease NOx emissions by 138 tons per year. This NOx decrease more than nets out the 23 ton overage. The requirements of 2005(c)(2) are satisfied.

Trading Zones Restrictions [2005(e)]: This facility is located in zone 1, and hence, can only obtain RTC from zone 1.

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 Appendix K.

(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));

Arizona Clean Fuels Refinery	2005	None	Engineering design and good combustion practice	Permit Technical Support Document
Citgo Corpus Christi Texas Refinery (TX-0478)	2005	3.9 lb/hr; (0.039 lb/MMBtu)(1)(3)	Engineering design and good combustion practice	RBLC
ConocoPhillips Ferndale Washington Refinery	2004	57.1 ppmvd @ 7%O2 and 1.9 lb/hr (0.082 lb/MMBtu)(1)	Engineering design and good combustion practice	RBLC
Murphy Oil Wisconsin Refinery	2004	0.6 lb/hr (2)	Engineering design and good combustion practice	PSD Permit

(1) Calculated based on lb/hr limit and incinerator capacity.
(2) Need to determine the burner capacity.
(3) Appears that this incinerator operates in standby mode.

The CO limit proposed by Chevron is lower than any limits identified on existing TGTU incinerator permits. The proposed burner, incinerator minimum temperature limit of 1450°F, and CO limit of 0.03 lb/mmbtu is considered BACT for CO and VOC. The incinerator permit will also require a CO CEMS for continuous compliance with the CO limit.

PM10 BACT – PM10 is generated in the thermal oxidizer through the combustion of natural gas and reduced sulfur species in the tail gas. The only identified control option for PM10 from thermal oxidizers is adherence to good combustion practice.

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. 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.

The permitted capacity of the incinerator is 41.9 MMBtu/hr. Table A-1 in Appendix A of Rule 2005 is specified to be for noncombustion sources and for combustion sources less than 40 Million BTUs per hour. The maximum allowable NOx emissions for a combustion source with a capacity of 40 MMBtu/hr is 1.31 lb/hr. Although the heat input of the TGTU incinerator is slightly above the largest capacity listed in this table, the NOx emissions of the incinerator, at 0.76 lb/hr, are well below the maximum allowed NOx emissions for the 40 MMBtu/hr. The incinerator passes the screening analysis since the maximum hourly NOx emissions of 0.76 lb/hr are below the allowable emissions of 1.31 lb/hr.

2012(c)(3)(A) and 2012(c)(3)(A) - The RECLAIM 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.

2011(f)(6) and 2012(h)(6) - A RECLAIM Facility Permit holder which installs a new major SOx and 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 of the major SOx and NOx source.

The incinerator is listed as a major NOx and SOX source in the "RECLAIM Source Type/Monitoring Unit" column of the incinerator listing in the RECLAIM Facility Permit. The general RECLAIM monitoring, testing, recordkeeping and reporting requirements of Rules 2011 and 2012 are specified in Sections F and G of the RECLAIM Facility Permit. Therefore, an equipment specific condition detailing the RECLAIM monitoring and recordkeeping requirements for the incinerator is not warranted. 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:

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 is being prepared for the proposed SOx scrubber. 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 from the TGTU Incinerator is 3.3 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.

The proposed construction of new permit units and modification of existing permit units complies with the requirements of Rule 1401 (See R1401 analysis).

Rule 2011: Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions, and Rule 2012: Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) emissions

As specified in the title of these regulations, they contain the monitoring, reporting, recordkeeping requirements for RECLAIM sources.

2011(c)(1)(C) and 2012(c)(1)(E) - All refinery tail gas units are subject to RECLAIM as major SOx and NOx sources. It is specified at Rule 2011: Appendix A, Chapter 2.A.3 and Rule 2012: Appendix A, Chapter 2.A.1, that the Facility Permit holder of each major SOx and NOx equipment shall install, calibrate, maintain, and operate an approved CEMS to measure and record the following:

- Sulfur oxide concentrations in the gases discharged to the atmosphere
- 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

Due to the high volume of tail gas sent to the incinerator, fuel flow cannot be utilized to calculate the incinerator exhaust gas flow. Therefore, the exhaust gas flow will be measured directly in the incinerator stack.

Air Contaminant	Significant Revision Emission Threshold Level (lb/day)	Emission Increase for Proposed Title V Revision (lb/day)
HAP	30	< 1
VOC	30	21.2
NO_x	40	18.4
PM-10	30	7.5
SO_x	60	59.4
CO	220	27.4

As seen in the table, none of the emission increases exceed the significant revision threshold. However, the proposed revision is a significant Title V revision since the proposed SRU will be subject to 40 CFR 60 Subpart Ja and 40 CFR 63 Subpart UUU. The Title V permit revision will be sent to EPA for a 45 day review period and will be made available to the public for a 30 day review period.

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 Construct, Section H of the RECLAIM/Title V Facility Permit, be issued for the proposed new construction and modifications of existing permit units.

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 will be the first revision of Chevron's initial Title V permit. Emission increases for this revision are compared against the maximum emission increase threshold for significant Title V revisions in the following table.