Significant Modification to a Covered Source
Review Summary

Application File No.: 0088-13

Permit No.: 0088-01-C

Applicant: Chevron USA Products Company

Facility Title: Chevron Hawaii Refinery
Located at 91-480 Malakole Street, Kapolei, Oahu

Mailing Address: Chevron USA Products Company
Hawaii Refinery
91-480 Malakole Street
Kapolei, HI 96707

Responsible Official: Mr. Thomas M. Kovar
Refinery Manager
(808) 682-5711

Point of Contact: Ms. Helen Mary Wessel
Environmental Specialists
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Application Date: Significant Modification application dated March 29, 2007

Proposed Project:

SICC 2911 (Petroleum Refining)

Background

In accordance with the Chevron Consent Decree Section I, Flaring Devices - NSPS applicability, the Chevron Hawaii Refinery is required to comply with 40 CFR 60 Subparts A and J for the Crude and FCC refinery flares. In order to comply with the Consent Decree, Chevron submitted Significant Modification application no. 0088-09, where the refinery proposed a Flare Vapor Recovery System Project to install a flare vapor recovery system on the Fluid Catalytic Cracking Unit (FCC) flare and move several pressure safety valves and flare sources from the Crude flare to the FCC flare to make the Crude flare a sweet flare (below 160 ppmv H_2S). They also planned to install a Continuous Emissions Monitoring System for H_2S on the Crude flare to ensure the requirements specified in 40 CFR §60.104(a)(1) are met. The overall project would allow the flare systems to operate reliably while recovering routine flare gas volumes from the FCC flare. This project was to be constructed by October 2006 to meet the Consent Decree required certification date of December 31, 2006, for both the FCC and Crude flares.

Chevron later requested in Significant Modification application no. 0088-09, to decouple the NSPS Subpart J - Standards of Performance for Petroleum Refineries requirements from the Flare Vapor Recovery System Project to expedite the permit review process. This is possible because there is nothing in the project itself that triggers the applicability of NSPS Subpart J. The only applicable Federal regulations are NSPS Subpart GGG - Standards of Performance

for Equipment Leaks of VOC in Petroleum Refineries and NSPS Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems. The acceptance of NSPS Subpart J for the flares was necessary only to meet the future Consent Decree requirements.

Therefore, in Significant Modification application no. 0088-13, Chevron is requesting to subject the FCC flare to NSPS Subparts A and J in order to comply with the Chevron Consent Decree Section I, Flaring Devices. Chevron is proposing to submit another Significant Modification application at a later date to subject the Crude flare to NSPS Subparts A and J in order to comply with the Consent Decree. Compliance with 40 CFR §60.104(a)(1) would be met at this time.

An application fee of $1,000.00 was submitted by the applicant and processed.

Equipment Description:

Flare Vapor Recovery Compressor System

The routine streams in the FCC flare were identified by Refinery Operations and Engineering. The routine "sour" gas streams, which contain H_2S, in the Crude Flare System will be rerouted to the FCC Flare System to be recovered.

The new Flare Vapor Recovery System will be sized to handle the routine FCC flare gas volumes and deliver the recovered flare gas to the wet gas compressor inlet in the FCC unit. The Flare Vapor Recovery System will be connected to the FCC flare header and pull suction from it. The recovered gas is returned to the FCC unit wet gas compressor and the gases processed in the gas recovery section of the FCC. In the FCC, the gas is separated into various process streams or fuel gas. It is ultimately "sweetened" in an amine contactor prior to being returned to the appropriate unit process columns within the refinery.

The FCC flare header pressure is normally 0 to 1.5 psig and must be maintained at this level for the flare system to function as an emergency safety device and not interfere with other process operations.

Every 3 to 5 years, the FCC wet gas compressor will be out of service for short durations. During these wet gas compressor outages, the recovered flare gas from the Flare Vapor Recovery System will be sent to the Flare Sulfur Emissions Reduction Process (FSERP) where it will be treated in a caustic (NaOH) scrubber before being added to the fuel gas mix drum. Delivery of the recovered flare gas to FSERP will require a higher discharge pressure for the Flare Vapor Recovery System.

The Flare Vapor Recovery System consists of one multistage centrifugal blower, two 50,000 scfh liquid ring compressors, two knock out drums with pumps, one separator, fin fan coolers, seal flush system, and other ancillary equipment.

The multistage centrifugal blower will be used when the recovered flare gas is being directed to the FCC wet gas compressor. When the recovered flare gas is required to be routed to the FSERP, the two liquid ring compressors will be used due to the higher discharge pressures required. The ancillary equipment associated with delivering the recovered flare gas to the FSERP operation is a chiller and a phase separator.

The centrifugal blower capacity will be designed to recover normal routine gas flow from the FCC Flare Header and up to 100,000 scfh. Each compressor has the capacity to handle the normal routine gas flow from the FCC flare header. The second compressor can be brought online when the first compressor is down for preventative maintenance or during upset conditions when the gas flow exceeds 50,000 scfh up to a maximum recovery of 100,000 scfh.

H_2S Flow Meters
Chevron has installed a flow meter in each of the Flare Systems. The flow meters will continue to be used for recording flow to each flare.

Applicable Requirements:

Hawaii Administrative Rules (HAR)
Title 11, Chapter 59 Ambient Air Quality Standards
Title 11, Chapter 60.1 Air Pollution Control
- Subchapter 1 General Requirements
- Subchapter 2 General Prohibition
  - HAR 11-60.1-31 Applicability
  - HAR 11-60.1-38 Sulfur Oxides from Fuel Combustion
- Subchapter 5 Covered Sources
- Subchapter 6 Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
  - HAR 11-60.1-111 Definitions
  - HAR 11-60.1-112 General Fee Provisions for Covered Sources
  - HAR 11-60.1-113 Application Fees for Covered Sources
  - HAR 11-60.1-114 Annual Fees for Covered Sources
  - HAR 11-60.1-115 Basis of Annual Fees for Covered Sources
- Subchapter 8 Standards of Performance for Stationary Sources

Federal Requirements
40 CFR Part 60 - Standards of Performance for New Stationary Sources (NSPS)
- Subpart A - General Provisions
- Subpart J - Standards of Performance for Equipment Petroleum Refineries

Non-Applicable Requirements:

Hawaii Administrative Rules (HAR)
Title 11, Chapter 60.1 Air Pollution Control
- Subchapter 7 Prevention of Significant Deterioration
- Subchapter 9 Hazardous Air Pollutant Sources
  - HAR 11.60.1-174 Maximum Achievable Control Technology (MACT) Emission Standards

Federal Requirements
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPS)

40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards)

New Source Performance Standards (NSPS):

The FCC Flare will be subject to NSPS Subpart J - Standards of Performance for Petroleum Refineries.

Prevention of Significant Deterioration (PSD):

This significant modification is not subject to PSD review as the modification is not considered a *major modification* to a major stationary source as defined in HAR §11-60.1-131. The net emissions increase is not significant. See Table 4.

Best Available Control Technology (BACT):

A Best Available Control Technology (BACT) analysis is applicable only to new covered sources and significant modifications to covered sources that have the potential to emit or a net emissions increase above significant levels as defined in HAR §11-60.1-1. A BACT analysis is not applicable since there is no net emissions increase above significant levels from the proposed modification. See Table 4.

Consolidated Emissions Reporting Rule (CERR):

40 CFR Part 51, Subpart A - Emission Inventory Reporting Requirements, determines CER based on the emissions of criteria air pollutants from Type A and Type B point sources (as defined in 40 CFR Part 51, Subpart A), that emit at the CER triggering levels shown in Table 1.

Table 1 – CERR/IN-HOUSE REPORTING APPLICABILITY

Pollutant	Type A CER Triggering Levels [1,2] (tpy)	Type B CER Triggering Levels [1] (tpy)	Pollutant	In-house Total Facility Triggering Levels [3] (tpy)
NO_x	≥2500	≥100	NO_x	≥25
SO_x	≥2500	≥100	SO_x	≥25
CO	≥2500	≥1000	CO	≥250
$PM_{10}/PM_{2.5}$	≥250/250	≥100/100	PM/PM_{10}	≥25/25
VOC	≥250	≥100	VOC	≥25
			HAPS	≥5

[1] Based on actual emissions
[2] Type A sources are a subset of Type B sources are the larger emitting sources by pollutant
[3] Based on potential emissions

There is no change from Covered Source Permit No. 0088-01-C. This Type A facility emits above the Type A CER and in-house triggering levels. Therefore, CER and annual emissions reporting requirements are applicable. Also, annual emissions reporting is required for covered sources.

Compliance Assurance Monitoring (CAM):

No change from Covered Source Permit No. 0088-01-C. This facility is subject to CAM at 1st permit renewal.

Synthetic Minor Source:

No change from Covered Source Permit No. 0088-01-C. This facility is not a synthetic minor.

Insignificant Activities:

No change from Covered Source Permit No. 0088-01-C.

Alternate Operating Scenarios:

No change from Covered Source Permit No. 0088-01-C.

Project Emissions:

Calculations for the project's net emission changes submitted by Chevron were developed by subtracting the baseline actual emissions from the post-project projected actual emission estimates. The net emission changes resulting from the proposed modifications to the existing FCC flare were all found to be well below the PSD significant emission thresholds. The results of the PSD evaluation are presented in the Table 4.

Annual emissions estimates for the FCC flare were calculated by applying AP-42 emission factors for each criteria pollutant to the annual refinery crude throughput. No emissions were estimated for particulate matter (PM/PM_{10}) or sulfuric acid mist (H_2SO_4). Based upon the AP-42 emission factors for refinery feed, PM emissions are considered negligible. The operating temperatures of the flares are in excess of the temperature conditions under which H_2SO_4 can be formed. Therefore, PM and H_2SO_4 emissions are not presented.

The Baseline Actual Emissions represent an average annual emissions estimate developed from a consecutive 24-month period within the past 10 years of refinery operation. The 24-month time period from January 2001 to December 2002 were determined to be most representative of normal operations. Therefore, the average annual crude throughput for 2001 and 2002 was used to determine the baseline actual emissions. The emissions attributed to the FCC flare were based on a percentage of gas flow rate to the FCC flare. Recent flow meter data was used to determine the percentage of gas flow to each flare. The FCC flare flow percentage was applied to the annual crude throughput based emissions to determine the amount attributable to each flare.

The Post-Project Projected Actual Emissions are based on an annual crude throughput estimate developed from refinery crude throughput projected over a five-year period extending from 2006 to 2010. Each successive yearly crude throughput was estimated to experience a 5% annual increase until it reached a maximum throughput of 23,725 Mbbls/yr or 65,000 bpd. The average annual throughput over the next five years was 22,724 Mbbls/yr or 62,230 bpd.

Since the Flare Vapor Recovery System will recover all normal gas flow to the FCC flare, the only post-project emissions attributed to the FCC flare will be from refinery fuel gas used to maintain the flare pilot burner. The VOC emissions are mainly attributed to the fugitive VOC

emission from the new Flare Vapor Recovery System components. The projected SO_2 emissions for the FCC flare were calculated using an emission factor developed from the H_2S limit of 160 ppmv in the refinery fuel gas. The project will result in a net reduction in NO_x, CO, and SO_2 and VOC emissions. See Table 4 for the project's pollutant emission estimates.

The project's net emission changes (potential emissions minus actual emissions) were developed by subtracting the baseline actual emissions from the potential emissions estimates. Potential emissions were based on a maximum refinery feed rate of 23,725,000 bbls/yr or 65,000 bpd. The net emission changes resulting from the proposed modifications to the existing equipment were all found to be below the PSD significant emission thresholds. See Table 4.

Table 2. - Baseline Actual Emissions

Source	Pollutant	Emission Factor (lb/1000 bbl)	Baseline Actual Emissions [3, 4, 5] (tpy)
FCC Flare	**NO_x**	18.9 [1]	154.28
	SO_2	26.9 [1]	219.58
	PM	0 [1]	0
	PM_{10}	0 [1]	0
	CO	4.3 [1]	35.1
	VOC combustion	0.8 [1]	6.53
	H_2SO_4 Mist	0 [2]	0
	HAPs		0.0013

1 Based on AP-42 Emission Factors (1/95) for Petroleum Refining, Table 5.1-1
2 Combustion temperature prevents formation of H_2SO_4 mist
3 Based on a baseline actual refinery feed rate of 18,860,300 bbl/yr
4 Based on a Crude Flare gas flow rate of 13.44%
5 Based on a FCC Flare gas flow rate of 86.56%

Table 3. - Projected Actual Emissions

Source	Pollutant	Emission Factor	Projected Actual Emissions [8, 9, 10] (tpy)
FCC Flare	**NO_x**	100 [2, 3]	0.07 [4]
	SO_2	27.02 [3, 5]	0.02 [4]
	PM	0[1]	0
	PM_{10}	0[1]	0
	CO	84 [2, 3]	0.06 [4]
	VOC combustion	5.5 [2, 3]	0.004 [4]
	VOC fugitive		3.55 [6]
	VOC total		3.56
	H_2SO_4 Mist	0 [7]	0
	HAPs	0.005	0.0065

1 Based on AP-42 Emission Factors (1/95) for Petroleum Refining, Table 5.1-1
2 Based on AP-42 Emission Factors (7/98) for Natural Gas Combustion, Tables 1.4-1 and 1.4-2
3 Units in lb/mmscf
4 Based on a FCC Flare - Pilot: RFG flowrate of 150 scf/hr @ 8,760 hrs/yr
5 Based on 160 ppm H_2S for the SO_2 emission factor, lb SO_2/mmscf = 1/379 * 160 ppm S * 64 = 27.02 lb/mmscf
6 Based on EPA's Protocol for Equipment Leak Emission Estimates, Table 2-10. Petroleum Industry Leak Rate/Screening Value Correlations, 11/95
7 Combustion temperature prevents formation of H_2SO_4 mist
8 Based on a projected actual refinery feed rate of 22,724,200 bbl/yr
9 Based on a Crude Flare gas flow rate of 13.44%
10 Based on a FCC Flare gas flow rate of 86.56%

Table 4. - Emissions Summary

Pollutant	Potential Emissions [1] (tpy)	Projected Actual Emissions (tpy)	Baseline Actual Emissions (tpy)	Net Emissions Change [2] (tpy)	Net Emissions Change [3] (tpy)	Significant Level (tpy)
NO_x	0.073	0.07	154.28	-154.21	-154.21	40
SO_2	0.021	0.02	219.58	-219.56	-219.56	40
PM	0	0	0	0	0	25
PM_{10}	0	0	0	0	0	15
CO	0.063	0.06	35.1	-35.04	-35.04	100
VOC	3.72	3.56	6.53	-2.81	-2.97	40
H_2SO_4 Mist	0	0	0	0	0	7
HAPs	0.0068	0.0065	0.0013	0.0055	0.0052	

[1] Based on a potential refinery feed rate of 65,000 bbl/day x 365 days/yr = 23,725,000 bbl/yr
[2] Net Emissions Change = Potential Emissions - Baseline Actual Emissions
[3] Net Emissions Change = Projected Actual Emissions - Baseline Actual Emissions

Air Quality Assessment:

An Ambient Air Quality Impact Assessment (AAQIA) was not performed on the FCC flare stack, since the net emissions from the flare will be reduced.

Significant Permit Conditions:

In this significant modification, the FCC flare will be subject to NSPS Subparts A and J, including requiring the FCC flare to combust refinery fuel gas meeting 40 CFR §60.104(a)(1) or a maximum H_2S content not to exceed 230 mg/dscm (160 ppmv). The flare section in Covered Source Permit No. 0088-01-C (Attachment II(E)) will be amended.

Conclusion and Recommendations:

Recommend issuance of a Significant Modification to existing Covered Source Permit No. 0088-01-C based on the significant permit conditions above. The proposed project will result in a net emissions decrease from the FCC flare. A 30-day public comment period and a 45-day EPA review period are also required.

Reviewer: Darin Lum
Date: 9/07