FLINT HILLS resources®
Corpus Christi Refineries

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P.O. Box 2608
Corpus Christi, Texas 78403-2608

October 22, 2015

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AIR PERMITS SECTION
6PD-R

Ms. Melanie Magee
United States Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200 (Mail Code: 6PD)
Dallas, Texas 75202-2733

RE: Flint Hills Resources Corpus Christi, LLC
Corpus Christi West Refinery – Domestic Crude Project
Request for Rescission of PSD Permit No. PSD-TX-6819A-GHG

Dear Ms. Magee:

Pursuant to 40 C.F.R. § 52.21(w)(2)(iii), Flint Hills Resources Corpus Christi, LLC (FHR) is hereby requesting that United States Environmental Protection Agency, Region 6 (EPA) rescind Permit No. PSD-TX-6819A-GHG, which was issued to FHR on May 23, 2014, for the Corpus Christi West Refinery Domestic Crude Project. Included with this request is a copy of the amendment to Texas Commission on Environmental Quality (TCEQ) Permit No. 6819A issued by TCEQ for the Domestic Crude Project along with TCEQ's Source Analysis & Technical Review.

According to 40 C.F.R. § 52.21(w)(2)(iii), a permit holder may request that EPA rescind a permit if it was issued for a modification that was classified as a major modification solely on the basis of an increase in emissions of greenhouse gases (GHGs). As documented in TCEQ's Source Analysis & Technical Review for the amendment of TCEQ Permit No. 6819A and Special Condition No. 34 of the TCEQ permit, the Domestic Crude Project did not constitute a major modification and, therefore, did not trigger prevention of significant deterioration (PSD) review for any non-GHG pollutants. Accordingly, PSD Permit No. PSD-TX-6819A-GHG is no longer required in light of recent court decisions.

The West Refinery Domestic Crude Project, which is currently under construction, will allow the FHR Corpus Christi West Refinery to process a larger percentage of domestic crude oil and will result in a modest increase in the total crude processing capacity of the refinery. The project involves construction of new emission units and changes to existing emission units authorized by the May 23, 2014, amendment to TCEQ Permit No. 6819A along with changes to existing emission units authorized under separate TCEQ permitting actions to achieve emission reductions for purposes of netting. As documented in TCEQ's Source Analysis & Technical Review,[1] construction of new emission units and changes to existing emission units will not result in a significant project emissions increase of carbon monoxide (CO), particulate matter (PM), sulfur dioxide (SO_2), or hydrogen sulfide (H_2S). Construction of new emission units and changes to existing emission units will, however, result in a significant project emissions increase for nitrogen oxide (NO_X), certain species of particulate matter (PM_{10} and $PM_{2.5}$), and volatile organic compounds (VOC). However, considering contemporaneous emissions increases and decreases the project will not cause a significant net emissions increase for NO_X, PM_{10}, $PM_{2.5}$, or VOC.

[1] See discussion of § 116.111(a)(2)(I) PSD Review Applicability on pages 3-4.

Therefore, the project was subject to the Texas minor new source review program and authorized through a minor amendment to TCEQ Permit No. 6819A. Emission reductions projects relied upon as part of the PSD netting analysis and authorized under separate permitting actions are required to be implemented pursuant to Special Condition No. 35 of amended Permit No. 6819A.

I hereby certify that PSD Permit No. PSD-TX-6819A-GHG is not being used, or planned to be used, for any regulatory compliance or enforcement purposes, and that the information contained in this request is factual and correct.

Please contact Curtis Taylor at (361) 242-5241 if you have any questions regarding this request or require additional information.

Sincerely,

Valerie Pompa
Vice President and Manufacturing Manager

VP/CT/kjf
Air 15-383; W 3 N 10

Attachments

ATTACHMENT

Permit No. 6819A issued by TCEQ for the Domestic Crude Project

Valerie Deh mike H. Dana Daren

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

COPY

Protecting Texas by Reducing and Preventing Pollution

May 23, 2014

MS VALERIE POMPA
VICE PRESIDENT AND MANUFACTURING MANAGER
FLINT HILLS RESOURCES CORPUS CHRISTI LLC
PO BOX 2608
CORPUS CHRISTI TX 78403-2608

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RECEIVED
JUN 02 2014
BY: .....

Re: Permit Amendment Application
Permit Number: 6819A
West Refinery
Corpus Christi, Nueces County
Regulated Entity Number: RN100235266
Customer Reference Number: CN603741463
Account Number: NE-0122-D

Dear Ms. Pompa:

This is in response to your letter received December 13, 2012 and your Form PI-1 (General Application for Air Preconstruction Permits and Amendments) concerning the proposed amendment to Permit Number 6819A. We understand that you propose to 1) construct several new sources, 2) modify several existing sources currently authorized by Permit 8803A, 3) transfer the both modified and affected sources from Permit 8803A to Permit 6819A, 4) transfer all maintenance, startup, and shutdown (MSS) activities for the West Refinery from Permit 8803A to Permit 6819A, and 5) incorporate by consolidation Permit by Rule Registration Nos. 103051 and 103706. Also, this will acknowledge that your application for the above-referenced amendment is technically complete as of May 23, 2014.

In accordance with Title 30 Texas Administrative Code (TAC) Section 116.116(b) and § 116.160 and based on our review, Permit Number 6819A is hereby amended. In addition, with this permitting action, Permit by Rule Registration Numbers 103051 and 103706 have been voided. This information will be incorporated into the existing permit file. Enclosed are revised general conditions (permit face), special conditions, and a maximum allowable emission rates table. We appreciate your careful review of the special conditions of the permit and assuring that all requirements are consistently met.

This amendment will be automatically void upon the occurrence of any of the following, as indicated in 30 TAC 116.120(a):

1. Failure to begin construction of the changes authorized by this amendment within 18 months from the date of this authorization.

2. Discontinuance of construction of the changes authorized by this amendment for a period of 18 consecutive months or more.

3. Failure to complete the changes authorized by this amendment within a reasonable time.

Upon request, the executive director may grant extensions as allowed in 30 TAC 116.120(b).

You may file a **motion to overturn** with the Chief Clerk. A motion to overturn is a request for the commission to review the executive director's decision. Any motion must explain why the commission should review the executive director's decision. According to 30 TAC § 50.139, an action by the executive director is not affected by a motion to overturn filed under this section unless expressly ordered by the commission.

A motion to overturn must be received by the Chief Clerk within 23 days after the date of this letter. An original and 11 copies of a motion must be filed with the Chief Clerk in person, or by mail to the Chief Clerk's address on the attached mailing list. On the same day the motion is transmitted to the Chief Clerk, please provide copies to the applicant, the executive director's attorney, and the Public Interest Counsel at the addresses listed on the attached mailing list. If a motion to overturn is not acted on by the commission within 45 days after the date of this letter, then the motion shall be deemed overruled.

You may also request **judicial review** of the executive director's approval. According to Texas Health and Safety Code § 382.032, a person affected by the executive director's approval must file a petition appealing the executive director's approval in Travis County district court within 30 days after the **effective date of the approval**. Even if you request judicial review, you still must exhaust your administrative remedies, which includes filing a motion to overturn in accordance with the previous paragraphs.

Your cooperation in this matter is appreciated. If you need further information or have any questions, please contact Mr. Tom Lawshae at (512) 239-2048 or write to the Texas Commission on Environmental Quality, Office of Air, Air Permits Division, MC-163, P.O. Box 13087, Austin, Texas 78711-3087.

Re: Permit Number: 6819A

This action is taken under authority delegated by the Executive Director of the TCEQ.

Sincerely,

Michael Wilson, P.E., Director
Air Permits Division
Office of Air
Texas Commission on Environmental Quality

MPW/tl

Enclosures

cc: Air Section Manager, Region 14 - Corpus Christi

Project Number: 186508

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A Permit Is Hereby Issued To
Flint Hills Resources Corpus Christi, LLC
Authorizing the Construction and Operation of
West Refinery
Located at **Corpus Christi, Nueces County, Texas**
Latitude 27° 49′ 38″ Longitude -97° 31′ 32″

Permit: 6819A
Amendment Date : May 23, 2014
Renewal Date: November 17, 2019

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code 116.116 (30 TAC 116.116)]
2. **Voiding of Permit.** A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC 116.120(a), (b) and (c)]
3. **Construction Progress.** Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC 116.115(b)(2)(A)]
4. **Start-up Notification.** The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC 116.115(b)(2)(B)(iii)]
5. **Sampling Requirements.** If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction; comply with any additional recordkeeping requirements specified in special conditions attached to the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates.** The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC 116.115(b)(2)(F)]
9. **Maintenance of Emission Control.** The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification for upsets and maintenance in accordance with 30 TAC 101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC 116.115(b)(2)(G)]
10. **Compliance with Rules.** Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to a condition of "air pollution" as defined in Texas Health and Safety Code (THSC) 382.003(3) or violate THSC 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit.

SPECIAL CONDITIONS

Permit Number 6819A

1. This permit authorizes emissions only from those points listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT) and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating requirements specified in the special conditions. **(11/09)**

Federal Applicability

2. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency regulations on Standards of Performance for New Stationary Sources promulgated in Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60): **(11/09)**

   A. Subpart A, General Provisions

   B. Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

   C. Subpart J, Standards of Performance for Petroleum Refineries

   D. Subpart Ja, Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007

   E. Subpart XX, Standards of Performance for Bulk Gasoline Terminals

   F. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006

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

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on National Emission Standards for Hazardous Air Pollutants in 40 CFR Part 61: **(02/11)**

   A. Subpart A, General Provisions

B. Subpart BB, National Emission Standard for Benzene Emissions from Benzene Transfer Operations

C. Subpart FF, National Emission Standard for Benzene Waste Operations

4. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:

A. Subpart A, General Provisions

B. Subpart F, National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry

C. Subpart G, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

D. Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

E. Subpart Y, National Emission Standards for Marine Tank Vessel Loading Operations

F. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

G. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Truck Loading

5. The tank truck loading rack is limited to a gasoline throughput of 96,000 gal/hr and 10,950,000 bbl/yr and a distillate throughput of 96,000 gal/hr and 4,380,000 bbl/yr. Records of product throughput shall be maintained.

A. Emissions from loading VOC with a vapor pressure equal to or greater than 0.5 pounds per square inch, absolute (psia) at maximum loading temperature shall be routed to the vapor combustion unit using a vacuum-assisted vapor collection system. Loading of VOC with a vapor pressure equal to or greater than 0.5 psia at maximum loading temperature shall be

immediately stopped if the vacuum-assisted vapor collection system is inoperative. Loading of VOC with a vapor pressure equal to or greater than 0.5 psia at maximum loading temperature shall not start or re-start until the vacuum-assisted vapor collection system is operational.

B. Emissions from loading VOC with a vapor pressure less than 0.5 psia at maximum loading temperature are not required to be controlled and may occur at the Truck Loading Rack, Emission Point No. (EPN) TR-101 or at the Truck Vapor Combustion Unit, EPN VCU. **(05/14)**

Marine Loading

6. Marine loading of product from these facilities shall not exceed the following rates:

Type of Vessel Loaded	Product Loaded	Loading Rate (bbl/hr)	Loading Rate (bbl/yr)
Ships Ocean Barge Shallow Barge	Toluene	6,000	7,300,000
	Benzene	6,000	4,000,000
	Xylene	10,000	18,250,000
	Light Straight Run (Mixed Pentanes)	5,000	4,000,000
	Gasolines/blendstocks	10,000	6,935,000
	Naphthas	10,000	8,030,000
	Cumene/pseudocumene	10,000	7,000,000
Ships Ocean Barges	Crude Oil	9,000	17,000,000
Shallow Barges	Crude Oil	6,000	

A. Each barge and ship loading dock shall utilize submerged fill. The collected vapors from the liquids in the table above and any VOC with a true vapor pressure equal to or greater than 0.50 psia from barge and/or ship vessel loading at Dock Nos. 8, 9 and 10 shall be collected and routed to the marine vapor control system (EPN VCS-1).

B. A pressure-monitoring device shall be installed at the common point of the vapor collection system between the barge/ship connection and the vacuum blowers/compressors to continuously measure pressure in the marine loading vapor collection system during loading of materials with a maximum true vapor pressure equal to or greater than 0.50 psia. The vapor collection piping shall be all welded between the Dock Safety Unit discharge flange and the vacuum blower liquid knockout pot inlet flange.

A blower/compression system shall be installed which will produce a vacuum in the loading system. The average pressure on the vapor collection system shall be maintained at a negative pressure of at least 1.5 inches water column during a loading period of material with a maximum true vapor pressure equal to or greater than 0.50 psia. The vacuum shall be recorded every fifteen minutes. In the event the pressure monitoring device is not functioning properly, barge loading operations and ship loading operations for material with a maximum true vapor pressure equal to or greater than 0.50 psia requiring use of the vapor combustor as an emission control device shall cease within two hours of malfunction. Additional loading requiring use of the vapor combustor shall not begin until the problems with the pressure monitoring device(s) are repaired.

Quality assured (or valid) data must be generated when barges and ships are loaded with material with a maximum true vapor pressure equal to or greater than 0.50 psia at this dock. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the barge and ship loading dock operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

C. All loading lines (hoses) and connectors shall be visually inspected for any defects prior to hookup. Lines and connectors that are visibly damaged shall be removed from service. Operations shall cease immediately upon detection of any liquid leaking from the lines or connections. Flanged connections shall be used for all loading operations. The following actions shall be taken prior to removing loading lines/hoses from marine vessels and shore facilities.

(1) After the transfer is complete, the loading line/hose shall be isolated at the connection to the shore piping. The loading line/hose shall be vented at the shore piping and shall be gravity drained or pressured into the marine vessel per the site operating procedure.

(2) The loading line/hose may be disconnected from the shore and/or marine vessel piping after the liquid has been removed to the extent possible by gravity draining to the vessel being loaded. If it is necessary to further empty the line/hose, any residual liquid in the line/hose shall be immediately drained directly into a covered sump. If the line/hose is not emptied, the open end(s) of the

line/hose shall be immediately capped, plugged, or blinded to prevent leakage.

(3) After the loading line/hose has been removed from the vessel, the vapor return line shall be immediately isolated.

The actions shall be documented as part of the loading procedure.

D. The permit holder shall maintain and update monthly an emissions record which includes calculated emissions of VOC from all marine loading operations over the previous rolling 12 month period. The record shall include the loading spot, control method used, quantity loaded in gallons, name of the liquid loaded, vapor molecular weight, liquid temperature in degrees Fahrenheit, liquid vapor pressure at the liquid temperature in psia, liquid throughput for the previous month and rolling 12 months to date. Records of VOC temperature are not required to be kept for liquids loaded from unheated tanks which receive liquids that are at or below ambient temperatures. Loading emissions shall be calculated using the methods used to determine the MAERT limits in the permit amendment application, PI-1 dated December 12, 2012. Sample calculations from the application shall be attached to a copy of the permit at the refinery. **(05/14)**

Marine Vapor Combustor

7. The marine vapor combustor firebox temperature shall be monitored continuously and recorded when exhaust vapors from the loading of VOC liquid is directed to it. The temperature measurement device shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency. The vapor combustor firebox temperature monitor shall be installed, calibrated at least annually, and maintained according to the manufacturer's specifications. The device shall have an accuracy of the greater of ±2 percent of the temperature being measured expressed in degrees Celsius or ±2.5°C. During barge and/or ship loading activities of chemicals that require VOC abatement, the average vapor combustor firebox temperature shall not fall below 1523°F over the entire loading period.

Quality assured (or valid) data must be generated when barges and ships are loaded with VOC liquid with a true vapor pressure equal to or greater than 0.50 psia at docks 8, 9 and 10. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time

(in minutes) that the barge and ship loading docks 8, 9 and 10 operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgement and the methods used recorded.

The presence of a pilot flame shall be confirmed by a pilot ultra violet scanner, a thermocouple, a temperature element or an agency approved equivalent measurement device before VOC with a true vapor pressure equal to or greater than 0.50 psia is initiated for loading onto a barge and/or ship. If the pilot flame is lost during barge and ship loading operation then an orderly system shutdown shall occur. **(05/14)**

8. The marine vapor combustor (EPN VCS-1) shall achieve a waste gas destruction efficiency at a minimum of 99.5 percent on an hourly average in the vapor combustor firebox while controlling the exhaust vapors from VOC liquid loading. **(05/14)**

Heaters

9. Nitrogen oxides (NO_x) and ammonia emissions from the Sat Gas No. 3 Hot Oil Heater (EPN SATGASHTR) shall not exceed the following rates/concentration (concentration is corrected to 3 percent oxygen).

Pollutant	Emission Limit
NO_x	0.01 lb/MMBtu (hourly average)
NO_x	0.0075 lb/MMBtu (365-day rolling average)
Ammonia	10 ppmvd (hourly average)

The Sat Gas No. 3 Hot Oil Heater exhaust shall be directed to a combustion catalyst and the hourly average carbon monoxide (CO) concentration shall not exceed 10 ppmvd at 3 percent oxygen.

NO_x and ammonia emissions from the NHT Charge Heater and the CCR Hot Oil Heater (EPN JJ-4) shall not exceed the following rates/concentration (concentration is corrected to 3 percent oxygen).

Pollutant	Emission Limit
NO_x	0.01 lb/MMBtu/hr (hourly average)
NO_x	0.0075 MMBtu/hr (365-day rolling average)
Ammonia	10 ppmvd (hourly average)

For the NHT Charge Heater and CCR Hot Oil Heater (EPN JJ-4), the hourly average CO concentration in the exhaust shall not exceed 50 ppmvd at 3 percent oxygen.

The limits of each heater above shall not apply when the heaters fire below 20 percent of its firing rate capacity (low load), so long as the emissions remain below the emission limits listed in MAERT. Low load operating conditions shall be limited to 876 hours per year per heater. **(05/14)**

10. Sat Gas No. 3 Hot Oil Heater shall be fired with natural gas and LPG Treating off-gas containing no more than 5 grains of total sulfur per 100 dry standard cubic feet (dscf) on an hourly average and no more than 0.5 grains/100 dscf on an annual average. The natural gas shall be continuously monitored for total sulfur content.

    The NHT Charge Heater and the CCR Hot Oil Heater shall be fired with fuel gas containing no more than 7.2 grains of total sulfur per 100 dscf on an hourly average and no more than 2 grains S/100 dscf on an annual average. The fuel gas shall be continuously monitored for total sulfur at the mix drum for the CCR #1 Fuel System. **(05/14)**

11. For the Sat Gas No. 3 Hot Oil Heater and the CCR Hot Oil Heater, the permit holder shall install and operate a fuel flow meter to measure the gas fuel usage for each heater. The monitored data shall be reduced to an hourly average flow rate at least once every day, using a minimum of four equally-spaced data points from each one-hour period. Each fuel flow monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. In lieu of monitoring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A. **(05/14)**

12. The NO_x emissions in the stack gases from the following combustion sources (Facility Identification Numbers [FINs] shall not exceed the lb/MMBtu values listed below. The averaging period shall be hourly, unless otherwise specified:

EPN	FIN	Description	Maximum Heat Specific EF (lb/MMBtu, LHV)
A-203	42BA1	Crude Heater	0.07
A-204	42BA3	Vacuum Heater	0.08

EPN	FIN	Description	Maximum Heat Specific EF (lb/MMBtu, LHV)
DDS-HTRSTK	DDS-CHGHTR	DDS Charge Heater	0.045(HHV)
DDS-HTRSTK	DDS-FRACBLR	DDS Fractionator Reboiler	0.045 (HHV)
KK-3	37BA1	Distillate Hydrotreater (DHT) Charge Heater	0.06
KK-3	37BA2	DHT Stripper Reboiler	0.06
LSGHTR	LSGHTR	LSG Hot Oil Heater	0.045 (HHV)
MX-1	MX-1	MX Unit Hot Oil Heater	0.07
R-201	43BF1	Crude Boiler	0.08

Note:

FIN - Facility Identification Number
LHV - Low Heating Value
HHV - High Heating Value
EF - Emission Factor

The NO_x limit of each heater above shall not apply when that heater fires below 20 percent of its firing rate capacity (low load), so long as NO_x emissions remain below the NO_x allowable emission rates. Low load operating conditions shall be limited to 876 hours per year per heater.

13. There shall be no visible emissions for periods exceeding five minutes over any two-hour period from EPNs A-203, A-204, DDS-HTRSTK, KK-3, LSGHTR, MX-1, and R-201. The opacity limitation shall be determined by using the procedures specified in Title 40 Code of Federal Regulations § 60.11(b) [40 CFR § 60.11(b)] upon request of the Texas Commission on Environmental Quality (TCEQ) Executive Director or TCEQ representatives. **(05/14)**

14. Except as provided for in the special conditions of this permit, the fuel for any heater, boiler, turbine, flare pilot, or flare sweep is limited to either natural gas, refinery fuel gas, or a combination of natural gas and refinery fuel gas.

Upon request by the Executive Director of the TCEQ or the Regional Administrator of the U. S. Environmental Protection Agency (EPA) or any local air pollution control agency having jurisdiction, the holder of this permit shall provide a sample and/or analysis of the fuel utilized or shall allow air pollution control agency representatives to obtain a sample for analysis.

For the following combustion sources, the total sulfur content shall not exceed 1 gr S/100 dscf on a rolling three-hour average or exceed 0.6 gr S/100 dscf on an annual average basis.

EPN	FIN	Description
A-203	42BA1	Crude Heater
A-204	42BA3	Vacuum Heater
LSGHTR	LSGHTR	LSG Hot Oil Heater
MX-1	MX-1	MX Unit Hot Oil Heater
KK-3	37BA1	DHT Charge Heater
KK-3	37BA2	DHT Stripper Reboiler
R-201	43BF1	Mid Crude Boiler
DDS-HTRSTK	DDS-CHGHTR	DDS Charge Heater
DDS-HTRSTK	DDS-FRACHTR	DDS Fractionator Reboiler

The fuel gas shall be continuously monitored for total sulfur content at the mix drum of the Mid Plant fuel system. **(05/14)**

15. For the following combustion sources, particulate matter (PM) less than 10 microns in diameter emissions shall not exceed the following, based on a daily average, when fired at maximum firing capacity. All of the following emission limits are based on the Higher Heating Value (HHV) of the fuel: **(05/14)**

EPN	FIN	Description	Emission Limit
A-203	42BA1	Crude Heater	0.0045 lb PM_{10}/MMBtu
A-204	42BA3	Vacuum Heater	0.0045 lb PM_{10}/MMBtu
R-201	43BF1	Boiler	0.0045 lb PM_{10}/MMBtu

16. The permit holder shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) to measure and record the in-stack concentration of pollutants listed from the combustion sources listed in Special Condition No. 17.

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

B. Section 1 below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; section 2 applies to all other sources:

(1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, Section 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager. Downtime is not considered to include periods when the CEMS is operational but the 24-hour span drift exceeds the allowable amounts.

(2) The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days, unless the monitor is required by a subpart of NSPS or NESHAPS, in which case zero and span shall be done daily without exception.

Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

All CGA exceedances of ±15 percent accuracy indicate that the CEMS is out of control.

C. The monitoring data shall be reduced to hourly average concentrations at least weekly, using a minimum of four equally-spaced data points from each one-hour period.

The individual average concentrations shall be reduced to units of pounds per hour and pounds per million BTU at least once every calendar quarter as follows:

The measured hourly average concentration from the CEMS shall be multiplied by the exhaust flow rate as measured directly, or determined by monitoring fuel flow, stack oxygen concentration, and the fuel gas heating value, to determine the hourly emission rate. The emission rate and fuel gas flow and heating value shall be used to determine the lb NOx/MMBtu heat input.

D. All monitoring data and quality-assurance data shall be maintained by the permit holder. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required RATA in order to provide them the opportunity to observe the testing.

F. Quality-assured (or valid) data must be generated when the heater is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the heater operated over the previous rolling 12-month period. The data availability shall be calculated as the total fired unit operating hours for which quality assured data was recorded divided by the total fired unit operating hours. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager. **(05/14)**

17. Special Condition No. 16 shall apply to the following sources and pollutants:

EPN	FIN	Source	Pollutant/Diluent Monitored
SATGASHTR	SATGASHTR	Sat Gas No. 3 Hot Oil Heater	NO_x, CO, O_2
JJ-4	39BA3900	NHT Charge Heater	NO_x, CO, O_2
JJ-4	39BA3901	CCR Hot Oil Heater	NO_x, CO, O_2
A-203	42BA1	Crude Heater	NO_x, CO, O_2
A-204	42BA3	Vacuum Heater	NOx, CO, O2

EPN	FIN	Source	Pollutant/Diluent Monitored
AA-4	01BF102	FCCU CO Boiler Off-Gas Scrubber	NO_x, SO_2 (per NSPS), O_2
AA-4	01BF102	FCCU CO Boiler Outlet Duct	CO (per NSPS) and O_2
LSGHTR	LSGHTR	LSG Hot Oil Heater	NO_x (per NSPS), CO, O_2
R-201	43BF1	Crude Boiler	NO_x (per NSPS), CO, O_2

18. The permit holder shall continuously monitor ammonia emissions from the heater SCR systems (EPNs SATGASHTR and JJ-4) using one of the following methods:

A. Install and operate two NOx CEMS, one located upstream of the SCR system and the other located downstream of the SCR system, which are used in association with ammonia injection rate and the following calculation procedure to estimate ammonia slip.

Ammonia slip, ppmvd = (a – (b x c / 1,000,000)) x 1,000,000 / b) x d

where:

a = ammonia injection rate (lb/hr)/17 (lb/lb-mole);
b = dry exhaust gas flow rate (lb/hr)/29 (lb/lb-mole);
c = change in measured NOx concentration, ppmvd, across catalyst; and
d = correction factor.

The correction factor shall be derived during compliance testing by comparing the measured and calculated ammonia slip. The ammonia injection rate and exhaust gas flow rate shall be recorded at least every 15 minutes and be recorded as hourly averages. Each flow monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or at least annually, whichever is more frequent, and shall be accurate to within 2 percent of span or 5 percent of the design value.

B. Install and operate a dual stream system of NOx CEMS at the exit of the SCR system. One of the exhaust streams would be routed, in an unconverted state, to one NOx CEMS and the other exhaust stream would be routed through a NH3 converter to convert NH3 to NOx and then to a second NOx CEMS. The NH3 slip concentration shall be calculated from the delta between the two NOx CEMS readings (converted and unconverted).

C. Install an ammonia CEMS approved by TCEQ.

All CEMS specified in this condition must meet the requirements of Special Condition No. 16. Quality-assured (or valid) data must be generated when gas is directed to the SCR system. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time that gas is directed to the SCR system over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded. **(05/14)**

19. The following requirements apply to capture systems for the marine vapor combustor (EPN VCS-1), the API Separator Flare (EPN V-8), and SCR systems for the hot oil heaters (EPNs SATGASHTR, and JJ-4).

A. Conduct a once a month visual, audible, and/or olfactory inspection of the capture system to verify there are no leaking components in the capture system.

B. For the vapor combustor, the following may be completed in lieu of the monthly inspection specified in part A. Once a year, verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

C. The control device shall not have a bypass, or if there is a bypass for the control device, comply with either of the following requirements:

(1) Install a flow indicator that records and verifies zero flow at least once every fifteen minutes immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere; or

(2) Once a month, inspect the valves, verifying the position of the valves and the condition of the car seals prevent flow out the bypass.

A deviation shall be reported if the monitoring or inspections indicate bypass of the control device.

D. The date and results of each inspection performed shall be recorded. If the results of any inspection are not satisfactory, the deficiencies shall be

recorded and the permit holder shall promptly take necessary corrective action, recording each action with the date completed. **(05/14)**

Fluid Catalytic Cracking Unit (FCCU) Process Requirements

20. The opacity of emissions from the FCCU scrubber stack shall not exceed 15 percent averaged over a six-minute period. The holder of this permit shall create and maintain records demonstrating compliance with the opacity standard. **(05/14)**

21. The maximum allowable concentrations of the following pollutants in the FCCU scrubber stack are given below:

Pollutant	Concentration Limit in parts per million by volume (ppmv)
CO	500 ppmv (hourly*) 50 ppmv (annual**)
NO_x	550 ppmv (hourly*) 93 ppmv (annual**)
Sulfur dioxide (SO_2)	250 ppmv (hourly*) 50 ppmv (7-day average***) 25 ppmv (annual**)
Ammonia	25 ppmv (hourly*) 15 ppmv (annual**)

* Hourly – averaged over one-hour period
** Annual – averaged over a rolling 365-day period
*** 7-day average – averaged over a 7-day period

(05/14)

22. Emissions from the FCCU scrubber stack shall not exceed 1.0 lb of PM per 1,000 lbs of coke burn-off averaged over a one-hour period.

An annual PM performance test shall be conducted on the FCCU scrubber stack using the applicable test methods in 40 CFR 60.106. The first annual performance test shall be conducted within 180 days following the issuance of the amendment to Permit No. 6819A for the Domestic Crude Project (application submitted on December 13, 2012, TCEQ Project No. 186508). Following the initial PM performance test, subsequent PM performance tests shall be conducted within 12 calendar months of the prior PM performance test, or sooner if FHR wishes to do so. FHR shall operate at a coke burn rate within 5% plus or minus of the coke burn rate during the prior PM performance test. **(05/14)**

Flare Process Requirements

23. Flares shall be designed and operated in accordance with the following requirements:

A. The flare systems shall be designed such that the combined assist natural gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal, upset, and maintenance flow conditions.

The heating value and velocity requirements shall be satisfied during operations authorized by this permit. Flare testing per 40 CFR § 60.18(f) may be requested by the appropriate regional office (or is required per NSPS subpart) to demonstrate compliance with these requirements.

B. Flares shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications.

C. Flares shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours.

Cooling Towers

24. The Mid Plant Cooling Tower No. 2 shall be monitored for VOC in accordance with the provisions of Paragraph 69(b) of the Consent Decree between EPA and Flint Hills Resources, LP, (U.S. et al. V. Koch Petroleum Group, L.P., Civil Action No. 00-2756 (PAM/SRN), U.S. District Court for District of Minnesota, April 25, 2001) as amended, as it pertains to the Corpus Christi West Refinery. Confirmed leaks shall be repaired and corrections shall be confirmed within the timelines prescribed in Paragraph 69(b) of said Consent Decree. The results of the monitoring and maintenance efforts shall be recorded, and such records shall be maintained for a period of five years. The records shall be made available to the TCEQ Executive Director upon request.

If the permit holder is no longer required by EPA to comply with Paragraph 69(b), the permit holder shall apply for a permit alteration or an amendment to

revise this cooling tower condition.

FHR shall determine compliance with the annual VOC (tons/year) MAERT limit for the Mid Plant Cooling Tower No. 2 by calculating actual annual VOC emissions using the El Paso Method, the calculation basis from MACT CC, and the length of time to repair from the time of sampling. Samples shall be taken at least monthly.

FHR shall comply with the recordkeeping requirements established by 40 CFR 63.655(i)(4)(iii) and maintain such records for at least five years. **(05/14)**

FHR shall report, in the first Excess Emissions and Monitoring System Performance Report (NSPS 60.7(c), Subpart J and Db and NESHAP BB) following submittal of its annual emissions inventory, any exceedance of the annual tons/year VOC limit for the Mid Plant Cooling Tower No. 2. **(05/14)**

25. The Mid Plant Cooling Tower No. 2 shall be operated and monitored in accordance with the following requirements:

A. The cooling tower shall be equipped with drift eliminators having manufacturer's design assurance of 0.0005% drift or less. Drift eliminators shall be maintained and inspected at least annually. The permit holder shall maintain records of all inspections and repairs.

B. Total dissolved solids (TDS) shall not exceed 5200 parts per million by weight (ppmw) on an hourly basis and 4600 ppmw on an annual average basis. Dissolved solids in the cooling water drift are considered to be emitted as PM, PM_{10}, and $PM_{2.5}$ as represented in the permit application calculations.

C. The Mid Plant Cooling Tower No. 2 shall be analyzed for particulate emissions using one of the following methods:

(1) Cooling water shall be sampled at least once per day for total dissolved solids (TDS); or

(2) TDS monitoring may be reduced to weekly if conductivity is monitored daily and TDS is calculated using a ratio of TDS-to-conductivity (in ppmw per µmho/cm or ppmw/siemens). The ratio of TDS-to-Conductivity shall be determined by concurrently monitoring TDS and conductivity on a weekly basis. The permit holder may use the average of two consecutive TDS-to-conductivity

ratios to calculate daily TDS; or

(3) TDS monitoring may be reduced to quarterly if conductivity is monitored daily and TDS is calculated using a correlation established for the Mid Plant Cooling Tower No. 2. The correlation factor shall be the average of nine consecutive weekly TDS-to-conductivity ratios determined using Condition No. (2) above provided the highest ratio is not more than 10% larger than the smallest ratio.

(4) The permit holder shall validate the TDS-to-conductivity correlation factor once each calendar quarter. If the ratio of concurrently sampled TDS and conductivity is more than 10% higher or lower than the established factor, the permit holder shall increase TDS monitoring to weekly until a new correlation factor can be established.

D. Cooling water sampling shall be representative of the cooling tower feed water and shall be conducted using approved methods.

(1) The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, and SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. Water samples should be capped upon collection, and transferred to a laboratory area for analysis. Short term and annual average emission rates of PM, PM_{10} and $PM_{2.5}$ shall be calculated using the measured TDS, the design drift rate and the daily maximum and average actual cooling water circulation rate. Alternately, the design maximum circulation rate may be used for all calculations.

(2) Alternate sampling and analysis methods may be used to comply with Paragraph D(1) of this condition with written approval from the TCEQ Regional Director.

(3) Records of all instrument calibrations and test results and process measurements used for the emission calculations shall be retained.

E. Emission rates of PM, PM_{10} and $PM_{2.5}$ shall be calculated using the measured TDS, the design drift rate and the daily maximum and average actual cooling water circulation rate for the short term and annual average rates. Alternately, the design maximum circulation rate may be used for all calculations. Emission records shall be updated monthly. **(05/14)**

Storage Tanks

26. Storage tanks are subject to the following requirements: The control requirements specified in parts A-C of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.50 psia at the maximum feed temperature or 95°F, whichever is greater, or (2) to storage tanks smaller than 25,000 gallons.

A. The tank emissions must be controlled as specified in one of the paragraphs below:

(1) An internal floating deck or "roof" shall be installed. A domed external floating roof tank is equivalent to an internal floating roof tank. The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

(2) An open-top tank shall contain a floating roof (external floating roof tank) which uses double seal or secondary seal technology provided the primary seal consists of either a mechanical shoe seal or a liquid-mounted seal and the secondary seal is rim-mounted. A weathershield is not approvable as a secondary seal unless specifically reviewed and determined to be vapor-tight.

B. For any tank equipped with a floating roof, the permit holder shall perform the visual inspections and any seal gap measurements specified in Title 40 Code of Federal Regulations § 60.113b (40 CFR § 60.113b) Testing and Procedures (as amended at 54 FR 32973, Aug. 11, 1989) to verify fitting and seal integrity. Records shall be maintained of the dates inspection was performed, any measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

C. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650 dated November 1, 1998 except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

D. The 75,000 and 100,000 Barrel Tanks (EPNs IFRTK1 and IFRTK2) shall be designed to completely drain their entire contents to a sump in a

manner that conforms to the requirements of API Code 650 dated July 2013. They shall also be constructed or equipped with a connection to a vapor recovery system that routes vapors from the vapor space under the landed roof (roof not floating on liquid) to a control device.

E. Except for labels, logos, etc. not to exceed 15 percent of the tank total surface area, uninsulated tank exterior surfaces exposed to the sun shall be white or unpainted aluminum. Storage tanks must be equipped with permanent submerged fill pipes.

F. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all storage tanks during the previous calendar month and the past consecutive 12 month period. The record shall include tank identification number, control method used, tank capacity in gallons, name of the material stored, VOC molecular weight, VOC monthly average temperature in degrees Fahrenheit, VOC vapor pressure at the monthly average material temperature in psia, VOC throughput for the previous month and year-to-date. Records of VOC monthly average temperature are not required to be kept for unheated tanks which receive liquids that are at or below ambient temperatures.

Emissions from tanks shall be calculated using the methods that were used to determine the MAERT limits in the permit amendment application, PI-1 dated December 12, 2012. Sample calculations from the application shall be attached to a copy of this permit at the plant site. **(05/14)**

Initial Determination of Compliance

27. Sampling ports and platform(s) shall be incorporated into the design of the combustion source stacks according to the specifications set forth in the attachment entitled "Chapter 2, Stack Sampling Facilities" of the TCEQ Sampling Procedures Manual. Alternate sampling facility designs must be submitted for approval to the TCEQ Regional Director. **(05/14)**

28. The permit holder shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the sources listed in Special Condition No. 29. The permit holder is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and the U.S. Environmental Protection Agency (EPA) Reference Methods.

Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60) testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

A. The appropriate TCEQ Regional Office shall be notified not less than 30 days prior to sampling. The notice shall include:

(1) Proposed date for pretest meeting.
(2) Date sampling will occur.
(3) Name of firm conducting sampling.
(4) Type of sampling equipment to be used.
(5) Method or procedure to be used in sampling.
(6) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.
(7) Procedure/parameters to be used to determine worst case emissions such as VOC with a true vapor pressure equal to or greater than 0.50 psia loaded into barges and ships from loading docks 8, 9 and 10 measured in gallons or barrels per hour during the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for the test reports. The TCEQ Regional Director must approve any deviation from specified sampling procedures.

B. Sources listed in Special Condition 29 shall be tested for the specific air contaminants listed in that condition.

C. The heaters shall be sampled within 60 days of achieving the maximum firing rate, but no later than 180 days after the heaters were modified. Heaters and the VCU shall also be sampled at such other times as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.

D. The VCU being sampled shall operate at the maximum hourly loading rate in gallons per hour or barrels per hour of any authorized VOC with a true vapor pressure equal to or greater than 0.50 psia into barges and ships

from loading docks 8, 9 and 10 during stack emission testing. The heaters shall be sampled at the maximum firing rates.

These conditions/parameters and any other primary operating parameters that affect the emission rate shall be monitored and recorded during the stack test. Any additional parameters shall be determined at the pretest meeting and shall be stated in the sampling report. Permit conditions and parameter limits may be waived during stack testing performed under this condition if the proposed condition/parameter range is identified in the test notice specified in paragraph A and accepted by the TCEQ Regional Office. Permit allowable emissions and emission control requirements are not waived and still apply during stack testing periods.

During subsequent operations,

(1) if the maximum hourly loading rate in gallons per hour or barrels per hour of VOC with a true vapor pressure equal to or greater than 0.50 psia into barges and ships from loading docks 8, 9 and 10 during stack emission testing is greater than that recorded during the test period, or

(2) the hourly heater firing rates exceed those maintained during the stack sampling,

stack sampling of that facility shall be performed at the new operating conditions within 120 days. This sampling may be waived by the TCEQ Air Section Manager for the region.

E. One copy of the final sampling report shall be forwarded to the appropriate TCEQ regional office within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions entitled "Chapter 14, Contents of Sampling Reports" of the TCEQ Sampling Procedures Manual. **(05/14)**

29. Special Condition Nos. 27 and 28 shall apply to the following sources:

EPN	FIN	Source Name	Pollutants
VCS-1	LW-8	Marine Vapor Combustor	CO, NO_x, VOC
SATGASHTR	SATGASHTR	Sat Gas No. 3 Hot Oil Heater	CO, NO_x, ammonia
JJ-4	39BA3900	NHT Charge Heater	CO, NO_x, ammonia
JJ-4	39BA3901	CCR Hot Oil Heater	CO, NO_x, ammonia
A-203	42BA1	Crude Heater	NO_x, SO_2, CO

EPN	FIN	Source Name	Pollutants
A-204	42BA3	Vacuum Heater	NO_x, SO_2, CO
AA-4	01BF102	FCCU CO Boiler Off-Gas Scrubber	NO_x, SO_2, PM, CO
DDS-HTRSTK	DDS-CHGHTR	DDS Charge Heater	NO_x, CO
DDS-HTRSTK	DDS-FRACBLR	DDS Fractionator Reboiler	NO_x, CO
KK-3	37BA1	DHT Charge Heater	NO_x
KK-3	37BA2	DHT Stripper Reboiler	NO_x
LSGHTR	LSGHTR	LSG Hot Oil Heater	NO_x, CO
MX-1	MX-1	MX Unit Hot Oil Heater	NO_x, CO
R-201	43BF1	Crude Boiler	NO_x, SO_2, CO

Leak Detection and Repair

30. Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. The requirements of paragraphs F and G shall not apply (1) where the Volatile Organic Compound (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

The exempted components may be identified by one or more of the following methods:

(1) piping and instrumentation diagram (PID);
(2) a written or electronic database or electronic file;
(3) color coding;
(4) a form of weatherproof identification; or
(5) designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe to monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe to monitor times. A difficult to monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. Any leaks discovered through AVO inspection shall be tagged and/or replaced or repaired.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45

days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved

gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC § 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations. **(05/14)**

M. As an alternative to comparing the daily emission rate of the components on the delay of repair (DOR) list to the total emissions from a unit shutdown per the requirements of Special Condition No. 30, Subparagraph I, the cumulative hourly emission rate of all components on the DOR list may be compared to ten percent of the fugitive short term allowable on the Maximum Allowable Emission Rate Table in order to determine if the TCEQ Regional Director and any local program is to be notified. In addition, the hourly emission rates of each specific compound on the DOR list must be less than ten percent of speciated hourly fugitive emission rate of the same compound. **(05/14)**

N. Relief valves and rupture discs are exempt from weekly visual monitoring if they are monitored quarterly via an approved gas analyzer, or if the relief valves are relieved to a control device. **(05/14)**

31. Fugitive areas F-SATGAS3, F-14-UDEX, F-37, F-39, F-40, F-42, and F-GB shall be monitored per Special Condition 30 prior to the startup of new or modified facilities associated with the Domestic Crude project. **(05/14)**

In addition to the weekly physical inspection required by Item E of Special Condition 30, all connectors in gas\vapor and light liquid service shall be monitored annually with an approved gas analyzer in accordance with Items F thru J of Special Condition 30. Alternative monitoring frequency schedules ("skip options") of Title 40 Code of Federal Regulations Part 63, Subpart H,

National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the monitoring frequency required by this permit condition. Compliance with this condition does not assure compliance with requirements of applicable state or federal regulation and does not constitute approval of alternative standards for these regulations.

Instead of the leak definition of 2,000 ppmv specified in Special Condition No. 30.H for pump and compressor seals in the NHT/CCR Platformer Unit, the permit holder shall use a leak definition of 500 ppmv for pumps and compressor seals in these areas. **(05/14)**

32. Piping, Valves, Pumps, and Compressors in Ammonia Service

A. Audio, olfactory, and visual checks for ammonia leaks within the SCR operating area shall be made every four hours.

B. Immediately, but no later than one hour upon detection of a leak, plant personnel shall take the following actions:

(1) Isolate the leak.
(2) Commence repair or replacement of the leaking component.
(3) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request. **(05/14)**

33. Piping, Valves, Pumps, and Compressors in Petroleum Land Loading Service - EPN F-101 **(11/09)**

A. Audio, olfactory, and visual checks for petroleum product leaks within the petroleum tank truck operating area shall be made monthly.

B. Every reasonable effort shall be made to repair or replace a leaking component within 15 days after a leak is found. If the repair or replacement of a leaking component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired or replaced until a scheduled

shutdown shall be identified in a list to be made available to representatives of the TCEQ upon request.

Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TCEQ upon request.

Federal New Source Review Applicability

34. The amendment application, PI-1 dated December 12, 2012, was determined not to be subject to major new source review by identifying projected actual emission rates for one or more facilities affected and unaffected by the project. Actual emissions from these facilities shall be monitored, recorded and reports made in accordance with 30 TAC § 116.127. **(05/14)**

35. The permit amendment, PI-1 application dated December 12, 2012, is conditioned on the completion of the following emission reduction projects represented in that application, as follows:

Cogeneration Pollution Control Project

Installation of Floating Roof in Tanks 15FB509, 15FB510, 40FB4014, 40FB4015, 40FB4016. 40FB3043, and 40FB3044

Replacement of Floating Roof in Tanks 08FB160

This reduction of emissions shall occur not later than the commencement of operation of the new and modified facilities associated with the Domestic Crude Project. The permit holder shall maintain records of these emission reductions. Construction of these facilities must commence as defined in 40 CFR § 52.21(b)(9) (PSD) no later than five years after all the emission reductions identified in the netting analysis are actually accomplished, or the above reductions are no longer creditable, and the amendment is void. **(05/14)**

Applicability of Emission Limits and Special Conditions

36. The emission limits and special conditions contained in this permit that are applicable to sources associated with the permit amendment application dated December 12, 2012 for the Domestic Crude Project are not effective until the relevant change authorized by the amendment is operated. Until that time, the source will comply with the special conditions and permit limit specified in

Permit No. 8803A. The permit holder shall submit a permit alteration request to remove this special condition within 90 days of completion of the change authorized by the amendment. **(05/14)**

Maintenance, Startup, and Shutdown

37. Startup and shutdown emissions due to the activities identified in Special Condition 38 are authorized from facilities and emission points in Flexible Permit 8803A and the facilities authorized by this permit. **(05/14)**

38. This permit authorizes the emissions from the facilities identified in Special Condition 37 for the planned maintenance, startup, and shutdown (MSS) activities summarized in the MSS Activity Summary (Attachment C) attached to this permit.

This permit authorizes emissions from the following temporary facilities used to support planned MSS activities at permanent site facilities: frac tanks, containers, vacuum trucks, facilities used for abrasive blasting, portable control devices identified in Special Condition 49, and controlled recovery systems. Emissions from temporary facilities are authorized provided the temporary facility (a) does not remain on the plant site for more than 12 consecutive months, (b) is used solely to support planned MSS activities at the permanent site facilities authorized by this permit, and (c) does not operate as a replacement for an existing authorized facility.

Attachment A identifies the inherently low emitting MSS activities that may be performed at the refinery. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.

Routine maintenance activities, as identified in Attachment B may be tracked through the work orders or equivalent. Emissions from activities identified in Attachment B shall be calculated using the number of work orders or equivalent that month and the emissions associated with that activity identified in the permit application.

The performance of each planned MSS activity not identified in Attachments A or B and the emissions associated with it shall be recorded and include at least the following information:

A. the physical location at which emissions from the MSS activity occurred, including the emission point number and common name for the point at which the emissions were released into the atmosphere;

B. the type of planned MSS activity and the reason for the planned activity;

C. the common name and the facility identification number, if applicable, of the facilities at which the MSS activity and emissions occurred;

D. the date of the MSS activity and its duration; and

E. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.

All MSS emissions shall be summed monthly and the rolling 12-month emissions shall be updated on a monthly basis. **(05/14)**

39. Process units and facilities, with the exception of those identified in Special Conditions 42, 43, 45, and Attachment A shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements.

A. The process equipment shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid. Equipment that only contains material that is liquid with VOC partial pressure less than 0.50 psi at the normal process temperature and 95°F may be opened to atmosphere and drained in accordance with paragraph C of this special condition. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded.

B. If mixed phase materials must be removed from process equipment, the cleared material shall be routed to a knockout drum or equivalent to allow for managed initial phase separation. If the VOC partial pressure is greater than 0.50 psi at either the normal process temperature or 95°F, any vents in the system must be routed to a control device or a controlled recovery system. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. Control must remain in place until degassing has been completed or the system is no longer vented to atmosphere.

C. All liquids from process equipment or storage vessels must be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids must be drained into a closed vessel unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of being drained. After draining is complete, empty open pans may remain in use for housekeeping reasons to collect incidental drips.

D. If the VOC partial pressure is greater than 0.50 psi at the normal process temperature or 95°F, facilities shall be degassed using good engineering practice to ensure air contaminants are removed from the system through the control device or controlled recovery system to the extent allowed by process equipment or storage vessel design. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

The following requirements do not apply to fugitive components, pumps, and compressors.

(1) For MSS activities identified in Attachment B, the following option may be used in lieu of (2) below. The facilities being prepared for maintenance shall not be vented directly to atmosphere, except as necessary to verify an acceptable VOC concentration and establish isolation of the work area, until the VOC concentration has been verified to be less than 10 percent of the lower explosive limit (LEL) per the site safety procedures.

(2) The locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded. PFD's or P&ID's may be used to demonstrate compliance with the requirement. Documented refinery procedures used to deinventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above. If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify acceptable VOC concentration prior to uncontrolled venting. The VOC sampling and analysis shall be

performed using an instrument meeting the requirements of Special Condition 40. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged. The facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than 10,000 ppmv or less than 10% of the lower explosive limit (LEL).

E. Gases and vapors with VOC partial pressure greater than 0.50 psi may be vented directly to atmosphere if all the following criteria are met:

(1) It is not technically practicable to depressurize or degas, as applicable, into the process.

(2) There is not an available connection to a plant control system (flare).

(3) There is no more than 50 lbs of air contaminant to be vented to atmosphere during shutdown or startup, as applicable.

All instances of venting directly to atmosphere per Special Condition 39.E must be documented when occurring as part of any MSS activity. The emissions associated with venting without control must be included in the work order, shift log, or equivalent for those planned MSS activities identified in Attachment B. **(05/14)**

40. Air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below.

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 CFR Part 60, Appendix A) with the following exceptions:

(1) The instrument shall be calibrated within 24 hours of use with a calibration gas such that the response factor of the VOC (or mixture of VOCs) to be monitored shall be less than 2.0. The calibration gas and the gas to be measured, and its approximate response factor shall be recorded.

(2) Sampling shall be performed as directed by this permit in lieu of section 8.3 of Method 21. During sampling, data recording shall not

begin until after two times the instrument response time. The date and time shall be recorded, and VOC concentration shall be monitored for at least 5 minutes and the highest concentration recorded. The highest measured VOC concentration shall not exceed the specified VOC concentration limit prior to uncontrolled venting.

(3) If a TVA-1000 series FID analyzer calibrated with methane is used to determine the VOC concentration, a measured concentration of 34,000 ppmv may be considered equivalent to 10,000 ppmv as VOC.

B. Colorimetric gas detector tubes may be used to determine air contaminant concentrations if they are used in accordance with the following requirements.

(1) The air contaminant concentration measured is less than 80 percent of the range of the tube. If the maximum range of the tube is greater than the release concentration defined in 3, the concentration measured is at least 20 percent of the maximum range of the tube.

(2) The tube is used in accordance with the manufacturer's guidelines.

(3) At least 2 samples taken at least 5 minutes apart must satisfy the following prior to uncontrolled venting:

measured contaminant concentration (ppmv) < release concentration.

Where the release concentration is:

10,000*mole fraction of the total air contaminants present that can be detected by the tube.

The mole fraction may be estimated based on process knowledge. The release concentration and basis for its determination shall be recorded.

Records shall be maintained of the tube type, range, measured concentrations, and time the samples were taken.

C. Lower explosive limit measured with an MSA Sirius lower explosive limit detector.

(1) The detector shall be calibrated monthly with a certified pentane calibration gas equivalent to 58 percent of the lower explosive limit (LEL) for pentane. Records of the calibration date/time and calibration result (pass/fail) shall be maintained.

(2) A daily functionality test shall be performed on each detector using the same certified gas standard used for calibration. The LEL monitor shall read no lower than 90 percent of the calibration gas certified value. Records, including the date/time and test results, shall be maintained.

(3) A certified methane gas standard equivalent to 29 percent of the LEL for methane may be used for calibration and functionality tests provided that the LEL response is within 95 percent of that for pentane.

(4) For any test environments in which pentane is not present in the sources tested, a determination shall be documented and maintained on site that the monitor as calibrated with the pentane simulant gas will provide conservatively accurate results and is a sensitive monitor for the components in question to set the decision to allow uncontrolled release of VOC to the atmosphere. Otherwise, an alternative monitoring approach must be used.

(5) The facility may submit a request for a determination that additional LEL detectors, which provide conservatively accurate results and are sensitive for the components in question, may be used. The permit holder shall obtain approval from the TCEQ prior to using a different LEL detector. **(05/14)**

D. Lower explosive limit measured with all other lower explosive limit detectors.

(1) The detector shall be calibrated within 30 days of use with a certified pentane calibration gas equivalent to 25 percent of the lower explosive limit (LEL) for pentane. Records of the calibration date/time and calibration result (pass/fail) shall be maintained.

(2) A functionality test shall be performed on each detector within 24 hours of use using the same certified gas standard used for

calibration. The LEL monitor shall read no lower than 90 percent of the calibration gas certified value. Records, including the date/time and test results, shall be maintained.

(3) A certified methane gas standard equivalent to 25 percent of the LEL for methane may be used for calibration and functionality tests provided that the LEL response is within 95 percent of that for pentane. **(05/14)**

41. If the removal of a component for repair or replacement results in an open ended line or valve, the open ended line is exempt from any NSR permit condition requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period:

A. A cap, blind flange, plug, or second valve must be installed on the line or valve, or demonstrate that the line, valve, component, etc, has been double blocked from the process; or

B. The permit holder shall verify that there is no leakage from the open-ended line or valve. The open-ended line or valve shall be monitored on a weekly basis in accordance with the applicable NSR permit condition for fugitive emission monitoring except that a leak is defined as any VOC reading greater than background. Leaks must be repaired no later than one calendar day after the leak is detected or a cap, blind flange, plug, or second valve must be installed on the line or valve. The results of this weekly check and any corrective actions taken shall be recorded. **(05/14)**

42. This permit authorizes emissions for the storage tanks identified in the attached facility list during planned floating roof landings. Unless the tank vapor space is routed to a control device meeting the requirements of Special Condition 49, tank roofs may only be landed for changes of tank service or tank inspection or maintenance as identified in the permit application. Emissions from change of service tank landings shall not exceed 10 tons of VOC in any rolling 12 month period. Tank roof landings include all operations when the tank floating roof is on its supporting legs. These emissions are subject to the maximum allowable emission rates indicated on the MAERT. The following requirements apply to tank roof landings.

A. The tank liquid level shall be continuously lowered after the tank floating roof initially lands on its supporting legs until the tank has been drained to the maximum extent practicable without entering the tank. Liquid level may be maintained steady for a period of up to three hours if necessary to

allow for valve lineups and pump changes necessary to drain the tank. This requirement does not apply where the vapor under a floating roof is routed to control or a controlled recovery system during this process.

This requirement does not apply if the level is lowered to allow for maintenance that is expected to be completed in less than 24 hours. In that case, the tank must be filled and the roof floated within 24 hours of landing the roof and the evolution documented in accordance with Special Condition 39.E.

B. If the VOC partial pressure of the liquid previously stored in the tank is greater than 0.50 psi at 95°F, tank refilling or degassing of the vapor space under the landed floating roof must begin within 24 hours after the tank has been drained unless the vapor under the floating roof is routed to control or a controlled recovery system during this period. Floating roof tanks with liquid capacities less than 100,000 gallons may be degassed without control if the VOC partial pressure of the standing liquid in the tank has been reduced to less than 0.02 psia prior to ventilating the tank. Controlled degassing of the vapor space under landed roofs shall be completed as follows:

(1) Any gas or vapor removed from the vapor space under the floating roof must be routed to a control device or a controlled recovery system and controlled degassing must be maintained until the VOC concentration is less than 10,000 ppmv or less than 10 percent of the LEL. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There shall be no other gas/vapor flow out of the vapor space under the floating roof when degassing to the control device or controlled recovery system.

(2) The vapor space under the floating roof shall be vented using good engineering practice to ensure air contaminants are flushed out of the tank through the control device or controlled recovery system to the extent allowed by the storage tank design until the VOC concentration is less than 10,000 ppmv or 10% of the LEL.

(3) A volume of gas equivalent to twice the volume of the vapor space under the floating roof must have passed through the control device or into a controlled recovery system, before the vent stream may be sampled to verify acceptable VOC concentration. The measurement of the gas volume shall not include any make-up air introduced into

the control device or recovery system. Documented refinery procedures used to de-inventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above. The VOC sampling and analysis shall be performed as specified in Special Condition 40.

(4) The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged.

(5) If ventilation is to be maintained with emission control, the control device shall be monitored in accordance with Special Condition 49.

Degassing must be performed every 24 hours unless there is no standing liquid in the tank or the VOC partial pressure of the remaining liquid in the tank is less than 0.15 psia.

C. The tank shall not be opened except as necessary to set up for degassing and cleaning, or ventilated without control, until either all standing liquid has been removed from the tank or the liquid in the tank has a VOC partial pressure less than 0.02 psia. These criteria may be demonstrated in any one of the following ways.

(1) Low VOC partial pressure liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC partial pressure of the liquid mixture remaining in the tank to less than 0.02 psia. This liquid shall be added during tank degassing if practicable. The estimated volume of liquid remaining in the drained tank and the volume and type of liquid added shall be recorded. The liquid VOC partial pressure may be estimated based on this information and engineering calculations.

(2) If water or other liquid is added or sprayed into the tank to remove standing VOC, acceptable vapor pressure may be demonstrated using any of the three methods below:

(a) Take a representative sample of the liquid remaining in the tank and verify no visible sheen using the static sheen test from 40 CFR 435 Subpart A, Appendix 1.

(b) Take a representative sample of the liquid remaining in the tank and verify hexane soluble VOC concentration is less than 1000 ppmw using EPA Method 1664 (may also use 8260B or 5030 with 8015 from SW-846).

(c) Stop ventilation and close the tank for at least 24 hours. When the tank manway is opened after this period, verify VOC concentration is less than 1000 ppmv through the procedure in Special Condition 40.

(3) No standing liquid verified through visual inspection.

Once the VOC partial pressure is verified less than 0.02 psia, any subsequent/additional water flushes that may be performed do not trigger additional verification. The permit holder shall maintain records to document the method used to release the tank.

D. Refilling of the 75,000 and 100,000 Barrel Tanks (EPNs IFRTK1 and IFRTK2) must be routed to control until the roof is floating on liquid. Tanks shall be refilled as rapidly as practicable until the roof is off its legs with the following exceptions:

(1) The vapor space under the floating roof is routed to control during refilling.

(2) The fill rate shall not exceed 3000 barrels per hour (bbl/hr) for any tank.

E. The occurrence of each roof landing and the associated emissions shall be recorded and the rolling 12-month tank roof landing emissions shall be updated on a monthly basis.

These records shall include at least the following information:

(1) the identification of the tank and emission point number, and any control devices or recovery systems used to reduce emissions;

(2) the reason for the tank roof landing;

(3) for the purpose of estimating emissions, the date, time and other information specified for each of the following events:

(a) the roof was initially landed,

(b) all liquid was pumped from the tank to the extent practical,
(c) start and completion of controlled degassing, and total volumetric flow,
(d) all standing liquid was removed from the tank or any transfers of low VOC partial pressure liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC partial pressure to <0.02 psi,
(e) if there is liquid in the tank, VOC partial pressure of liquid, start and completion of uncontrolled degassing, and total volumetric flow,
(f) refilling commenced, liquid filling the tank, and volume necessary to float the roof, and
(g) tank roof off supporting legs, floating on liquid.

(4) the estimated quantity of each air contaminant, or mixture of air contaminants, emitted between Events (c) and (g) with the data and methods used to determine it. The emissions associated with roof landing activities shall be calculated using the methods described in Section 7.1.3.2 of AP-42 "Compilation of Air Pollution Emission Factors, Chapter 7 - Storage of Organic Liquids" dated November 2006 and the permit application. **(05/14)**

43. Fixed roof tanks shall not be ventilated without control, until either all standing liquid has been removed from the tank or the liquid in the tank has a VOC partial pressure less than 0.02 psia. This shall be verified and documented through one of the criteria identified in Special Condition 42.C. Fixed roof tanks manways may be opened without emission controls when there is standing liquid with a VOC partial pressure greater than 0.02 psi vapor as necessary to set up for degassing and cleaning. One manway may be opened when necessary to allow access to the tank to remove or de-volatilize the remaining liquid. The emission control system shall meet the requirements of Special Condition 42.B.(1) through 42.B.(5) and records maintained per Special Condition 42.E.(3)c through 42.E.(3)e, and 42.E.(4). Low vapor pressure liquid may be added to and removed from the tank as necessary to lower the vapor pressure of the liquid mixture remaining in the tank to less than 0.02 psia. **(05/14)**

44. The following requirements apply to vacuum and air mover truck operations to support planned MSS at this site:

A. Vacuum pumps and blowers shall not be operated on trucks containing or vacuuming liquids with VOC partial pressure greater than 0.50 psi at 95°F unless the vacuum/blower exhaust is routed to a control device or a controlled recovery system.

B. When the vacuum pump is operating, equip fill line intake with a "duckbill" or equivalent attachment if the hose end cannot be submerged in the liquid being collected.

C. A daily record containing the information identified below is required for each vacuum truck in operation at the site each day.

(1) Prior to initial use, identify any liquid in the truck. Record the liquid level and document that the VOC partial pressure is less than 0.50 psi if the vacuum exhaust is not routed to a control device or a controlled recovery system. After each liquid transfer, identify the liquid transferred and document that the VOC partial pressure is less than 0.50 psi if the vacuum exhaust is not routed to a control device or a controlled recovery system.

(2) For each liquid transfer made with the vacuum operating, record the duration of any periods when air may have been entrained with the liquid transfer. The reason for operating in this manner and whether a "duckbill" or equivalent was used shall be recorded. Short, incidental periods, such as those necessary to walk from the truck to the fill line intake, do not need to be documented.

(3) If the vacuum truck exhaust is controlled by a device other than an engine or oxidizer, VOC exhaust concentration shall be measured using an instrument meeting the requirements of Special Condition 40 upon commencing each transfer, at the end of each transfer, and as required by Special Condition 49 during each transfer.

(4) The volume in the vacuum truck at the end of the day, or the volume unloaded, as applicable.

D. The permit holder shall determine the vacuum truck emissions each month using the daily vacuum truck records and the calculation methods utilized in the permit application. If records of the volume of liquid transferred for each uncontrolled vacuum truck pick-up are not maintained, the emissions shall be determined using the physical properties of the liquid vacuumed with the greatest potential emissions. Rolling 12 month vacuum truck emissions shall also be determined on a monthly basis.

E. If the VOC partial pressure of all the liquids vacuumed into the truck is less than 0.10 psi, this shall be recorded when the truck is unloaded or

leaves the plant site and the emissions may be estimated as the maximum potential to emit for a truck in that service as documented in the permit application. The recordkeeping requirements in Special Condition 44.A through 44.D do not apply. **(05/14)**

45. The following requirements apply to frac, or temporary, tanks and vessels used in support of MSS activities.

A. Except for labels, logos, etc. not to exceed 15 percent of the tank/vessel total surface area, the exterior surfaces of these tanks/vessels that are exposed to the sun shall be white or aluminum. This requirement does not apply to tanks/vessels that only vent to atmosphere when being filled.

B. These tanks/vessels must be covered and equipped with fill pipes that discharge within 6 inches of the tank/vessel bottom. If the VOC partial pressure of the liquid in the tank is greater than 0.5 psi at 95°F, the tanks vents must be routed to a control device or controlled recovery system when the tank is being filled.

C. These requirements do not apply to vessels storing less than 100 gallons of liquid that are closed such that the vessel does not vent to atmosphere.

D. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all frac tanks during the previous calendar month and the past consecutive 12 month period. The record shall include tank identification number, dates put into and removed from service, control method used, tank capacity and volume of liquid stored in gallons, name of the material stored, VOC molecular weight, and VOC partial pressure at the estimated monthly average material temperature in psia. Filling emissions for tanks shall be calculated using the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Loading Operations" and standing emissions determined using: the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Storage Tanks."

E. If the tank/vessel is used to store liquid with VOC partial pressure less than 0.10 psi at 95°F, records may be limited to the days the tank is in service and the liquid stored. Emissions may be estimated based upon the potential to emit as identified in the permit application. **(05/14)**

46. The following requirements apply to tank MSS activities to ensure acceptable off-site impacts.

A. Tank MSS emissions activities include tank degassing, tank opening, tank refilling following a degassing/cleaning until the roof is floated, and tank refilling not following a degassing/cleaning until the roof is floated. Only one of each type of activity may occur at any time for any liquid type (crude oil, benzene, lights, and distillates) at the site. Different tank MSS emissions activities may occur concurrently.

B. All emissions from tanks with landed roofs being filled with product grade benzene shall be routed to a control device meeting the requirements of Special Condition 49 unless the tank has been cleaned, degassed, and is at least 1650 feet from the property line. All emissions from tanks with landed roofs being filled with reformate shall be routed to a control device meeting the requirements of Special Condition 49 unless the tank has been cleaned, degassed, and is at least 1,300 feet from the property line. For benzene and reformate tanks, a refill following a tank degassing and a refill not following a tank degassing will not occur at the same time unless the emissions from both are controlled.

C. The MSS emissions from the SRU Incinerators and emissions from controlled tank refills not following a tank degassing/cleaning at Tanks FB511, FB512, FB513, or FB514 cannot occur at the same time if the material in the tank produces a hydrogen sulfide head space concentration of greater than 50 ppmv.

D. Emissions from tanks with landed roofs being filled with liquids that generate hydrogen sulfide concentrations greater than 10 ppmv in the landed roof headspace (crude oil, sour water and sour intermediates) shall be routed to a control device meeting the requirements of Special Condition 49. The following applies to tanks within 750 feet of the property line that may have a hydrogen sulfide head space concentration greater than 50 ppmv.

(1) If filling a tank with a landed roof not following a tank degassing/cleaning, the fill rate will be lowered so that the hourly sulfur dioxide emission rate is at or below 4.44 lb/hr.

(2) Degassing of these tanks shall not occur while controlling the filling one of these tank that had not been degassed and cleaned.

E. The permit holder shall determine the potential hydrogen sulfide generated during tank refilling as reference in parts C and D of this condition by sampling the vapors when the liquid level is at approximately half the height of the landed roof and when the liquid level is within 10

percent of the height of the landed roof. The sampling shall be performed in accordance with Special Condition 40.B with the exception of 40.B.(3) This determination shall be made at least once for each type of liquid. **(05/14)**

47. The MSS activities represented in the permit application may be authorized under permit by rule only if the procedures, emission controls, monitoring, and recordkeeping are the same as those required by this permit. **(05/14)**

48. All permanent facilities must comply with all operating requirements, limits, and representations during planned startup and shutdown unless alternate requirements and limits are identified in this permit. Alternate requirements for emissions from routine emission points are identified below:

A. Combustion units, with the exception of flares, at this site are exempt from NOx and CO operating requirements identified in special conditions and representations during planned maintenance, startup, and shutdown if the following criteria are satisfied.

(1) The emission caps or maximum allowable emission rates in the permit authorizing the facility are not exceeded.

(2) The start-up period does not exceed in duration as listed in the following table and the firing rate does not exceed 75 percent of the design firing rate. The time it takes to complete the shutdown does not exceed 4 hours. For maintenance events occurring while a combustion source is in normal operation, the maintenance period shall not exceed the startup duration.

EPN	Source Name	Startup Duration (hrs)*
D-3, 04BA4ST	Cumene Hot Oil Heater	36
B-1A, B	Coker Charge Heater	19
II-7	HDC Splitter Heaters	24
N-103	Parex #2 Hot Oil Heater	12
N-104	MSTDP Reactor Heater	12
KK-3	GOHT Charge Heater	13
JJ-2	CCR Charge Heaters	40
JJ-6	Xylene Column Reboiler	12
A-103, 40BA101ST	West Crude Heater	44
A-103, 40BA401ST	West Vacuum Heater	46
A-203	Mid Crude Heater	44
A-204	Mid Vacuum Heater	46

EPN	Source Name	Startup Duration (hrs)*
LSGHTR	LSG Hot Oil Heater	36
MX-1	MX Unit Hot Oil Heater	10
DDS-HTRSTK	DDS Charge heater	14
DDS-HTRSTK	DDS Fractionator Reboiler	14
N-3, 61BA1201ST	Parex #1 Hot Oil (Raffinate) Heater	12
N-3, 61BA1202ST	Parex #1 Hot Oil (Extract) Heater	12
Various	All combustion sources not listed above, except flares	8

* The beginning of Combustion Source Startup is defined as when the first burner is lit

(3) Control devices are started and operating properly when venting a waste gas stream.

B. The limits identified below apply to the operations of the specified facilities during startup and shutdown.

(1) The FCC startup emissions shall be routed to the operating FCC scrubber and the hourly average pollutant concentrations shall be less than those specified in Permit 8803A for normal operations. FCC preheat emissions may exhaust through EPN FCCURXVENT. Refractory cure emissions may exhaust through EPN FCCURCVENT.

(2) The SRU incinerators (EPNs H-15A, H-15B, and H-15C) shall oxidize at least 99.9 percent of the hydrogen sulfide directed to them to sulfur dioxide during the SRU start-up evolution. SRU seal legs may vent to atmosphere during seal leg, sulfur pit or eductor maintenance. The minimum sulfur recovery efficiency and exhaust concentrations specified for normal operations in Permit 8803A do not apply during periods of start-up or shutdown.

(3) The flare gas recovery unit shutdown shall be planned for periods when the flare system will not be utilized to control planned process unit MSS.

(4) Decoking of the heaters identified in the following table shall be performed using the shot blast, pigging, or burn-out techniques.

The PM emissions shall be controlled by cyclones to less than 0.01 grain/scf when using the shot blast technique.

FIN	EPN	Description
42BA1	41BA1MSS	Decoking for Mid-Crude Charge Heater
42BA3	42BA3MSS	Decoking for Mid-Crude Vacuum Heater
40BA101	40BA101MSS	Decoking for West Crude Charge Heater
40BA401	40BA101MSS	Decoking for West Crude Charge Heater
16BA1601	16BA1601MSS	Decoking for Coker Charge Heater

(5) The MSTDP catalyst shall be purged with nitrogen to the flare gas recovery unit prior to purging the reactor with air to a flare. The air purge shall be directed to the flare until the VOC concentration is less than 10,000 ppmv. The new or regenerated catalyst shall be conditioned with the exhaust routed to a flare.

(6) Sulfur terminal MSS: The sulfur degassing pit vents shall be covered and sulfur shall not be loaded into the degassing pit while flushing the LO-CAT mobile bed absorber. The sulfur degassing pit shall be isolated during cleaning of the LO CAT unit.

(7) The Cogen turbine shall be operated for no more than 12 hours and at no more than 8 MW of power production during startup without adding steam for NOx control.

C. A record shall be maintained indicating that the start and end times each of the activities identified above occur and documentation that the requirements for each have been satisfied. **(05/14)**

49. Control devices required by this permit for emissions from planned MSS activities are limited to those types identified in this condition. Control devices shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours.

Each device used must meet all the requirements identified for that type of control device. Controlled recovery systems identified in this permit shall be directed to an operating refinery process or to a collection system that is vented through a control device meeting the requirements of this permit condition.

A. Carbon Adsorption System (CAS):

(1) The CAS shall consist of 2 carbon canisters in series with adequate carbon supply for the emission control operation.

(2) The CAS shall be sampled down stream on the first can and the concentration recorded at least once every hour of CAS run time to determine breakthrough of the VOC. The sampling frequency may be extended using either of the following methods:

(a) It may be extended to up to 30 percent of the minimum potential saturation time for a new can of carbon. The permit holder shall maintain records including the calculations performed to determine the minimum saturation time.

(b) The carbon sampling frequency may be extended to longer periods based on previous experience with carbon control of a MSS waste gas stream. The past experience must be with the same VOC, type of facility, and MSS activity. The basis for the sampling frequency shall be recorded. If breakthrough is monitored on the initial sample of the upstream can when the polishing can is put in place, a permit deviation shall be recorded.

(3) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 40.

(4) Breakthrough is defined as the highest measured VOC concentration at or exceeding 100 ppmv above background. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new final polishing canister within four hours or prior to the next required sample, whichever is greater. In lieu of replacing canisters, the flow of waste gas may be discontinued until the canisters are switched. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

(5) Records of CAS monitoring shall include the following:

(a) Sample time and date.
(b) Monitoring results (ppmv).
(c) Canister replacement log.

(6) Single canister systems are allowed if the time the carbon canister is in service is limited to no more than 30% of the minimum potential saturation time. The permit holder shall maintain records for these systems, including the calculations performed to determine the saturation time. The time limit on carbon canister service shall be recorded and the expiration date attached to the carbon can.

(7) Liquid scrubbers may be used upstream of carbon canisters to enhance VOC capture provided such systems are closed systems and the spent absorbing solution is discharged into a closed container, vessel, or system.

B. Thermal Oxidizer.

(1) The thermal oxidizer firebox exit temperature shall be maintained at not less than 1400°F and waste gas flows shall be limited to assure at least a 0.5 second residence time in the fire box while waste gas is being fed into the oxidizer.

(2) The thermal oxidizer exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurements shall be made at intervals of six minutes or less and recorded at that frequency. Temperature measurements recorded in continuous strip charts may be used to meet the requirements of this section.

The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5°C.

C. Internal Combustion Engine.

(1) The internal combustion engine shall have a VOC destruction efficiency of at least 99 percent.

(2) The engine must have been stack tested with butane to confirm the required destruction efficiency within the past 12 months. VOC shall be measured in accordance with the applicable United States Environmental Protection Agency (EPA) Reference Method during the stack test and the exhaust flow rate may be determined from

measured fuel flow rate and measured oxygen concentration. A copy of the stack test report shall be maintained with the engine. There shall also be documentation of acceptable VOC emissions following each occurrence of engine maintenance which may reasonably be expected to increase emissions including oxygen sensor replacement and catalyst cleaning or replacement. Stain tube indicators specifically designed to measure VOC concentration shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable VOC analyzers meeting the requirements of Special Condition 40 are also acceptable for this documentation.

(3) The engine shall be operated with an oxygen sensor-based air-to-fuel ratio (AFR) controller. Documentation for each AFR controller that the, manufacturer's, or supplier's recommended maintenance has been performed, including replacement of the oxygen sensor as necessary for oxygen sensor based controllers shall be maintained with the engine. The oxygen sensor shall be replaced at least quarterly in the absence of a specific written recommendation.

D. The plant flare system operated as required by Permit 8803A. **(05/14)**

50. No visible emissions shall leave the property due to abrasive blasting. **(05/14)**

51. Black Beauty, Garnet Sand, and coal slag may be used for abrasive blasting. The permit holder may also use blast media that meet the criteria below:

A. The media shall not contain asbestos or greater than 1.0 weight percent crystalline silica.

B. The weight fraction of any metal in the blast media with a short term effects screening level (ESL) less than 50 micrograms per cubic meter as identified in the most recently published TCEQ ESL list shall not exceed the ESLmetal/1000.

C. The MSDS for each media used shall be maintained on site.

Blasting media usage and the associated emissions shall be recorded each month and the rolling 12 month total emissions updated. **(05/14)**

Recordkeeping Summary

52. The permit holder shall maintain the following records electronically or in hard copy format for at least five years. These records shall be used to demonstrate compliance with the Special Conditions and the limits specified in the MAERT:

A. Records associated with 40 CFR 60, Subparts A, Db, J, Ja, XX, GGG, and GGGa;

B. Records associated with 40 CFR 61, Subparts A, BB, and FF;

C. Records associated with 40 CFR 63, Subparts A, F, G, H, Y, CC, and DDDDD;

D. Tank truck loading throughput records as required by Special Condition 5;

E. Marine loading throughput records as required by Special Condition 6;

F. Vapor combustor firebox temperature records as required by Special Condition 7;

G. Fuel gas flow rate records as required by Special Condition 11;

H. CEMS records as required as required by Special Conditions 16 and 18;

I. AVO fugitive inspection records as required by Special Condition 19;

J. Opacity records as required by Special Condition 20;

K. FCCU performance test records as required by Special Condition 22;

L. Flare monitoring records as required by Special Condition 23;

M. Cooling tower monitoring records as required by Specials Condition 24 and 25;

N. Storage tank inspection records as required by Special Condition 26;

O. Stack sampling records as required by Special Condition 28;

P. Fugitive monitoring records as required by Special Condition 30, 31, 32, and 33;

Q. Emissions monitoring records as required by Special Condition 34; and

R. Maintenance, startup, and shutdown records as required by Special Conditions 37 to 51.

Dated May 23, 2014

ATTACHMENT A
Permit Numbers 6819A
INHERENTLY LOW EMITTING ACTIVITIES

Activity	VOC	NO_x	CO	PM	H_2S/SO_2
Water washing of equipment	x				X
Combustion shut off devices	x				X
Aerosol Cans Degassing/Crushing	x				
Inspection, maintenance, blowdown, repair, replacement, adjustment, testing and calibration of instrumentation/analyzer/analytical equipment	x	x	x		X
Materials Handling (i.e. Catalyst, insulation, clay, lime, sand, carbon, salt, refractory handling)				x	
Removal of Sulfur Deposits from LO-CAT System					X
Shot Blasting of Heater Tubes				x	
Inspection, maintenance, repair and replacement of carbon canisters	x				X
Inspection, maintenance, repair and replacement of filters, screens, baskets, and strainers	x				X
Inspection, maintenance, blowdown, and repairs on water circulating systems (cooling, boiler, potable)	x				X
Inspection, maintenance, blowdown, repair and replacement of monitoring/measuring equipment (e.g., sight glasses, rotometers, meter proving)	x				X
Pan emissions associated with exchanger backflushes; deadleg blowdowns; salt dryer inspections/refills; Oil changes on pumps and other small motors; pump seal, pump case, seal cooler replacements	x				X
Combinations of the above	x		x	x	X

Dated May 23, 2014

ATTACHMENT B
Permit Numbers 6819A

ROUTINE MAINTENANCE ACTIVITIES

Pump, compressor, vessel, exchanger, fugitive, component (valve, pipe, or flange) repair/replacement, or combinations of the preceding not included in Attachment A

Dated May 23, 2014

ATTACHMENT C
Permit Numbers 6819A

MSS ACTIVITY SUMMARY

Facilities	Description	Emissions Activity	EPN
all process units	process unit shutdown/depressurize/drain	vent to flare gas recovery unit (FGRU) or flare*	MSSFLR
all process units	process unit purge/degas/drain	vent to atmosphere	MSSATM
all process units	process unit start-up	vent to FGRU or flare*	MSSFLR
all process units and tanks	preparation for facility/component repair/replacement	vent to FGRU or flare*	MSSFLR
all process units and tanks	preparation for facility/component repair/replacement	vent to atmosphere	MSSATM
all process units and tanks	recovery from facility/component repair/replacement	vent to FGRU, flare* or control device	MSSFLR
all process units and tanks	recovery from facility/component repair/replacement	vent to atmosphere	MSSATM
all process units and tanks	preparation for unit turnaround or facility/component repair/replacement	remove liquid	MSSATM
FCC	Start-up/shutdown/vent	warm up, refractory cure, and start-up with torch oil, and vent reactor	MSSPRO
all floating roof tanks	tank roof landing	operation with landed roof	MSSATM
all floating roof tanks	degas of tank with landed roof	controlled degassing	MSSATM

Facilities	Description	Emissions Activity	EPN
SRU	Start-up/shutdown/meltout	vent directly to incinerator on start-up and meltout	MSSPRO
SRU seal legs	Periodic seal leg, sulfur pit and eductor maintenance	seal leg vapors vent to atmosphere instead of the incinerator (via sulfur pit)	MSSATM
see Attachment A	miscellaneous low emitting activities	see Attachment A	MSSATM
all production-related	abrasive blasting	PM from blasting media	MSSATM
cogen	turbine startup without steam	turbine start-up	MSSPRO
sulfur terminal	LO-CAT daily and quarterly maintenance	degassing pit vents not direct to LO-CAT	MSSATM
MSTDP	catalyst regeneration/replacement	initially vented to flare gas recovery system, then flare, and atmosphere	MSSPRO
furnaces identified in SC33	decoke		

* Emissions shall not be directed to a flare unless the FGRU is undergoing planned MSS.

Dated May 23, 2014

Emission Sources - Maximum Allowable Emission Rates

Permit Number 6819A

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SATGASHTR	Sat Gas No. 3 Hot Oil Heater	CO	3.29	14.43
		NO_x	4.50	14.78
		SO_2	6.06	2.65
		PM	4.60	15.23
		PM_{10}	4.60	15.23
		$PM_{2.5}$	4.60	15.23
		VOC	0.28	1.22
		NH_3	1.89	8.28
JJ-4	CCR Hot Oil Heater/NHT Charge Heater (combined stack)	CO	5.32	23.29
		NO_x	1.62	5.31
		SO_2	4.95	6.03
		PM	1.83	4.78
		PM_{10}	1.83	4.78
		$PM_{2.5}$	1.83	4.78
		VOC	0.87	3.82
		NH_3	0.68	2.97
TR-101	Truck Loading Rack	VOC	5.94	(6)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
VCU	Truck Vapor Combustion Unit	CO	8.02	26.88
		NO_x	3.21	10.75
		SO_2	0.27	0.01
		PM	0.08	0.01
		PM_{10}	0.08	0.01
		$PM_{2.5}$	0.08	0.01
		VOC	8.02	22.62
R-201	43BF1 Boiler	CO	22.15	24.25
		NO_x	15.99	70.05
		SO_2	0.63	1.66
		PM	1.00	4.38
		PM_{10}	1.00	4.38
		$PM_{2.5}$	1.00	4.38
		VOC	1.20	5.24
KK-3	37BA1 DHT Charge Heater/37BA2 DHT Stripper Reboiler (combined stack)	CO	6.40	28.02
		NO_x	7.68	33.60
		SO_2	0.40	1.06
		PM	1.28	5.60
		PM_{10}	1.28	5.60
		$PM_{2.5}$	1.28	5.60
		VOC	0.76	3.34
DDS-HTRSTK	DDS Charge Heater/DDS Fractionator Reboiler (combined stack)	CO	4.00	17.52
		NO_x	3.60	15.76
		SO_2	0.22	0.60
		PM	0.60	2.62
		PM_{10}	0.60	2.62
		$PM_{2.5}$	0.60	2.62
		VOC	0.44	1.90

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
A-203	42BA1 Crude Heater	CO	23.75	104.04
		NO_x	33.23	145.57
		SO_2	1.51	3.96
		PM	2.38	10.40
		PM_{10}	2.38	10.40
		$PM_{2.5}$	2.38	10.40
		VOC	2.84	12.43
A-204	42BA3 Vacuum Heater	CO	7.49	32.81
		NO_x	11.99	52.53
		SO_2	0.48	1.25
		PM	0.75	3.28
		PM_{10}	0.75	3.28
		$PM_{2.5}$	0.75	3.28
		VOC	0.89	3.92
LSGHTR	LSG Hot Oil Heater	CO	11.12	48.71
		NO_x	10.01	43.84
		SO_2	0.64	1.67
		PM	1.65	7.24
		PM_{10}	1.65	7.24
		$PM_{2.5}$	1.65	7.24
		VOC	1.20	5.24
MX-1	54BA1 MX Unit Hot Oil Heater	CO	4.00	17.50
		NO_x	5.59	24.49
		SO_2	0.25	0.67
		PM	0.66	2.89
		PM_{10}	0.66	2.89
		$PM_{2.5}$	0.66	2.89
		VOC	0.48	2.09

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
VCS-1	Marine Vapor Combustor	CO	6.44	5.47
		NO_x	2.65	2.25
		SO_2	2.80	2.03
		PM	0.60	0.51
		PM_{10}	0.60	0.51
		$PM_{2.5}$	0.60	0.51
		VOC	16.05	17.06
		H_2S	0.03	0.02
V-8	API Separator Flare	CO	2.20	9.64
		NO_x	0.26	1.13
		SO_2	0.12	0.50
		VOC	1.07	4.68
		H_2S	0.0012	0.0050
40FB4020	Additive Tank	VOC	10.48	0.13
40FB4021	Additive Tank	VOC	10.48	0.13
40FB4022	Additive Tank	VOC	10.48	0.13
40FB4023	Additive Tank	VOC	10.48	0.13
40FB4024	Additive Tank	VOC	10.48	0.13
40FB108	Additive Tank	VOC	1.05	0.01
40FB109	Additive Tank	VOC	1.05	0.01
F-101	Process Fugitives (5)	VOC	0.25	1.09
F-VCS-1	Process Fugitives (5)	VOC	0.95	4.14
F-SATGAS3	Sat Gas No. 3 Fugitives	VOC	2.66	11.66
F-14-UDEX	UDEX Fugitives	VOC	0.02	0.07
F-37	DHT Fugitives	VOC	4.06	17.78

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
F-39	NHT/CCR Fugitives	VOC	2.77	12.13
F-40	West Crude Fugitives	VOC	5.07	22.23
F-42	Mid Crude Fugitives	VOC	8.82	38.63
F-GB	Gasoline Blender Fugitives	VOC	1.16	5.08
F-TK-VOC	VOC Tank/Loading Fugitives	VOC	0.67	2.93
F-01	FCCU Fugitives	VOC	17.81	77.99
F-26	Hydrocracker Fugitives	VOC	5.66	24.78
SCRNH3FUG	SCR Ammonia Fugitives	NH_3	0.07	0.29
F-S-202	Mid-Plant Cooling Tower No. 2	VOC	1.26	5.52
		PM	0.39	1.51
		PM_{10}	0.20	0.76
		$PM_{2.5}$	0.04	0.15
		H_2S	0.0001	0.0003
IFRTK1	100,000 bbl IFR Tank	VOC	0.54	1.99
IFRTK2	75,000 bbl IFR Tank	VOC	0.47	1.76
FB108R1	Tank 08FB108R1	VOC	5.09	19.01
FB109R	Tank 08FB109R	VOC	4.16	15.30
FB142	Tank 08FB142	VOC	8.39	32.83
		H_2S	0.32	0.21
FB147	Tank 08FB147	VOC	10.01	38.10
		H_2S	0.33	0.21
FB137	Tank 08FB137	VOC	5.53	20.93
		H_2S	0.21	0.13
FB402	Tank 11FB402	VOC	3.03	11.88
FB403	Tank 11FB403	VOC	3.55	14.14
FB408	Tank 11FB408	VOC	0.96	---
FB409	Tank 11FB409	VOC	0.89	---

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FB410	Tank 11FB410	VOC	0.88	---
FB408 FB409 FB410	Annual Cap for Tanks 11FB408, 11FB409, and 11FB410	VOC	---	2.35
FB507	Tank 15FB507	VOC	4.21	18.66
FB508	Tank 15FB508	VOC	1.25	---
FB510	Tank 15FB510	VOC	1.14	---
FB508 FB510	Annual Cap for Tanks 15FB508 and 15FB510	VOC	---	2.67
FB3041	Tank 40FB3041	VOC	54.60	2.76
FB3043	Tank 40FB3043	VOC	0.60	---
FB3044	Tank 40FB3044	VOC	0.60	---
FB3043 FB3044	Annual Cap for Tanks 40FB3043 and 40FB3044	VOC	---	1.03
FB4010	Tank 40FB4010	VOC	3.69	---
		H_2S	0.14	---
FB4011	Tank 40FB4011	VOC	3.60	---
		H_2S	0.13	---
FB4010 FB4011	Annual Cap for Tanks 40FB4010 and 40FB4011	VOC	---	19.73
		H_2S	---	0.17
FB4012	Tank 40FB4012	VOC	1.62	5.63
FB4013	Tank 40FB4013	VOC	3.04	11.85
FB4014	Tank 40FB4014	VOC	0.66	0.88
FB4015	Tank 40FB4015	VOC	0.66	0.63
FB4016	Tank 40FB4016	VOC	0.58	---
FB509	Tank 15FB509	VOC	0.80	---
FB4016 FB509	Annual Cap for Tanks 40FB4016 and 15FB509	VOC	---	1.67

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
	Planned MSS Emissions (7)	NO_x	228.04	16.58
		CO	262.28	28.95
		SO_2	1726.99	56.97
		PM	27.44	1.30
		PM_{10}	23.91	0.67
		$PM_{2.5}$	23.91	0.67
		VOC	1069.14	30.77
		H_2S	6.69	0.46
AA-4	FCCU CO Boiler/Scrubber	CO	358.92	157.21
		NO_x	586.55	467.11
		SO_2	370.94	162.47
		PM	58.30	235.70
		PM_{10}	58.30	235.70
		$PM_{2.5}$	58.30	235.70
		VOC	1.68	7.35
		NH_3	10.90	28.63

Emission Sources - Maximum Allowable Emission Rates

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
H_2S - hydrogen sulfide
NH_3 - ammonia
(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) Emissions from loading VOC with a vapor pressure less than 0.5 psia at maximum loading temperature may occur at Emission Point No. (EPN) TR-101 or EPN VCU. The potential annual loading emissions from EPN TR-101 are included in the annual allowable for EPN VCU.
(7) The MSS activities associated with these emissions caps are identified in Attachment C to this permit.

Date: May 23, 2014

ATTACHMENT

Source Analysis & Technical Review
(Supporting Permit No. 6819A issued by TCEQ for the Domestic Crude Project)

Permit Amendment
Source Analysis & Technical Review

Company	**Flint Hills Resources Corpus Christi, LLC**	Permit Number	**6819A**
City	**Corpus Christi**	Project Number	**186508**
County	**Nueces**	Account Number	**NE-0122-D**
Project Type	**Amend**	Regulated Entity Number	**RN100235266**
Project Reviewer	**Mr. Tom Lawshae**	Customer Reference Number	**CN603741463**
Site Name	**West Refinery**		

Project Overview

Flint Hills Resources Corpus Christi, LLC, (Flint Hills) operates the West Refinery in Corpus Christi, Nueces County, Texas. It submitted this amendment application to authorize an expansion to its operations that would increase the total crude oil processing capacity at the West Refinery. The project involves 1) the construction of several new sources, 2) the modification of several existing sources currently authorized by Permit 8803A, 3) the transfer of both modified and affected sources from Permit 8803A to Permit 6819A, 4) the transfer of all maintenance, startup, and shutdown (MSS) activities for the West Refinery from Permit 8803A to Permit 6819A, and 5) the incorporation by consolidation of Permit by Rule Nos. 103051 and 103706.

Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)	Project Changes at Major Sources (Baseline Actual to Allowable)*
PM	276.86	294.85	+17.96	+23.79
PM_{10}	275.57	294.07	+18.50	+23.01
$PM_{2.5}$	275.57	292.79	+17.22	+22.41
VOC	728.85	570.18	-158.67	+64.60
NOx	935.16	903.75	-31.41	+67.29
CO	1340.16	539.52	-800.64	+63.27
SO_2	397.90	241.53	-156.37	+11.74
H_2S	2.66	1.21	-1.45	+0.72
NH_3	28.63	40.17	+11.54	NA

*Net emissions increases for contemporaneous period are included in the PSD section.

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	**January 14, 2014**
Compliance period:	**September 1, 2008 to August 31, 2013**
Site rating & classification:	**6.16 (Satisfactory)**
Company rating & classification:	**2.31 (Satisfactory)**
If the rating is 50<RATING<55, what was the outcome, if any, based on the findings in the formal report:	**NA**
Has the permit changed on the basis of the compliance history or rating?	**No**

Public Notice Information - 30 TAC Chapter 39 Rules

Rule Citation	Requirement	
39.403	Is Public Notice Required?	**Yes**
	Date Application Received:	**December 13, 2012**
	Date Administratively Complete:	**January 11, 2013**
	Small Business Source?	**No**

Rule Citation	Requirement	
	Date Leg Letters mailed:	**February 11, 2013**
39.603	Date Published:	**February 20, 2013**
	Publication Name:	***Corpus Christi Caller-Times***
	Pollutants:	**Carbon monoxide, nitrogen oxides, sulfur dioxide, ammonia, hydrogen sulfide, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, and organic compounds (including but not limited to) bromine**
	Date Affidavits/Copies Received:	**February 26, 2013**
	Is bilingual notice required?	**Yes**
	Language:	**Spanish**
	Date Published:	**February 11, 2013**
	Publication Name:	***El Tejano Hispanic Community Magazine***
	Date Affidavits/Copies Received:	**February 26, 2013**
	Date Certification of Sign Posting / Application Availability Received:	**March 26, 2013**
39.604	Public Comments Received?	**Yes**
	Hearing Requested?	**Yes**
	Meeting Request?	**No**
	Date Meeting Held:	**Flint Hills negotiated a settlement with Environmental Integrity Project and Center for Environmental Justice, the organizations that requested the contested case hearing. As part of the settlement, the hearing request was withdrawn on December 12, 2013.**
	Date Response to Comments sent to OCC:	**May 23, 2014**
	Request(s) withdrawn?	**Yes**
	Date Withdrawn:	**December 12, 2013.**
	Consideration of Comments:	**Comments were withdrawn.**
	Is 2nd Public Notice required?	**Yes**
39.419	Date 2nd Public Notice/Preliminary Decision Letter Mailed:	**March 18, 2014**
39.413	Date Cnty Judge, Mayor, and COG letters mailed:	**March 18, 2014**
	Date Federal Land Manager letter mailed:	**NA**
39.605	Date affected states letter mailed:	**NA**
39.603	Date Published:	**March 27, 2014**
	Publication Name:	***Corpus Christi Caller-Times***
	Pollutants:	**Carbon monoxide, nitrogen oxides, sulfur dioxide, ammonia, hydrogen sulfide, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, and organic compounds**
	Date Affidavits/Copies Received:	**April 10, 2014**

Rule Citation	Requirement	
	Is bilingual notice required?	**Yes**
	Language:	**Spanish**
	Date Published:	**March 27, 2014**
	Publication Name:	***El Tejano Hispanic Community Magazine***
	Date Affidavits/Copies Received:	**April 10, 2013**
	Date Certification of Sign Posting / Application Availability Received:	**April 30, 2014**
	Public Comments Received?	**No**
	Meeting Request?	**No**
	Date Meeting Held:	**NA**
	Hearing Request?	**No**
	Date Hearing Held:	**NA**
	Request(s) withdrawn?	**NA**
	Date Withdrawn:	**NA**
	Consideration of Comments:	**Comments were withdrawn**
39.421	Date RTC, Technical Review & Draft Permit Conditions sent to OCC:	**May 23, 2014**
	Request for Reconsideration Received?	**No**
	Final Action:	**Permit issued**
	Are letters Enclosed?	**Yes**

Construction Permit & Amendment Requirements - 30 TAC Chapter 116 Rules

Rule Citation	Requirement	
116.111(a)(2)(G)	Is the facility expected to perform as represented in the application?	**Yes**
116.111(a)(2)(A)(i)	Are emissions from this facility expected to comply with all TCEQ air quality Rules & Regulations, and the intent of the Texas Clean Air Act?	**Yes**
116.111(a)(2)(B)	Emissions will be measured using the following method:	**Monitoring natural gas for total sulfur content; monitoring fuel gas for H_2S content; CEMS to monitor NOx, CO, O2, and SO2 from combustion sources; CEMS to measure ammonia from SCR systems; VOC and TDS testing of cooling tower water; stack sampling of combustion sources; 28VHP and AVO fugitive monitoring; VOC monitoring of MSS activities**
	Comments on emission verification:	**No**
116.111(a)(2)(D)	Subject to NSPS?	**Yes**
	Subparts A, Db, J, Ja, XX, GGG, & GGGa	
116.111(a)(2)(E)	Subject to NESHAP?	**Yes**
	Subparts A, BB, & FF	
116.111(a)(2)(F)	Subject to NESHAP (MACT) for source categories?	**Yes**
	Subparts A, F, G, H, Y, CC, & DDDDD	
116.111(a)(2)(H)	**Nonattainment review applicability:** The site is located in Nueces County, which is designated as attainment for all pollutants. Nonattainment review is not applicable.	
116.111(a)(2)(I)	**PSD review applicability:**	

Rule Citation	Requirement		
	The West Refinery is a named major source. Project increases for PM, CO, SO_2, and H_2S are below PSD thresholds. Netting exercises produced net decreases of PM_{10} (-2.13 tpy), $PM_{2.5}$ (-4.28 tpy), VOC (-48.34), and NO_x (-217.82). PSD review is not applicable.		
116.111(a)(2)(L)	Is Mass Emissions Cap and Trade applicable to the new or modified facilities?		**No**
	If yes, did the proposed facility, group of facilities, or account obtain allowances to operate:		**NA**
116.140 - 141	Permit Fee: $75,000.00	Fee certification:	**R311754**

Title V Applicability - 30 TAC Chapter 122 Rules

Rule Citation	Requirement
122.10(13)	**Title V applicability:** Title V is applicable. The site operates under Permit O-1272.
122.602	**Periodic Monitoring (PM) applicability:** The permit conditions have the following periodic monitoring requirements for sources that are either new or modified by this project: Special Condition 10 requires 1) the monitoring of the total sulfur content of the natural gas and fuel gas burned by the Sat Gas No. 3 Hot Oil Heater, the NHT Charge Heater, and the CCR Hot Oil Heater, and 2) the monitoring of the gas fuel usage for all three heaters. Special Condition 14 requires the monitoring of the H_2S content of the fuel gas burned by a number of heaters and boilers. Special Condition 16 requires the installation of CEMS on a number of combustion sources to monitor NO_x, CO, O_2, and SO_2. Special Condition 18 requires continuous monitoring of ammonia emissions from the SCR systems installed on the Sat Gas No. 3 Hot Oil Heater, the NHT Charge Heater, and the CCR Hot Oil Heater. Special Condition 19 requires either monthly AVO monitoring or annual Method 21 monitoring of the capture systems for the SCR systems for the Sat Gas No. 3 Hot Oil Heater, the Marine Vapor Combustor, and the API Separator Flare. Special Conditions 24 and 25 require VOC and TDS monitoring of cooling tower water. Special Condition 28 requires stack sampling of a number of combustion sources. Special Condition 30 requires 28VHP fugitive monitoring. Special Condition 31 requires 28CNTA fugitive monitoring. Special Condition 32 requires AVO fugitive monitoring of components in ammonia service. Special Condition 33 requires AVO fugitive monitoring of components in gasoline service. Special Conditions 39 and 42 require VOC monitoring of MSS degassing activities.
122.604	**Compliance Assurance Monitoring (CAM) applicability:** The only control device modified by this project is the Marine Vapor Combustor (EPN VCS-1). General CAM requirements for it are found in Special Condition 19.

Request for Comments

Received From	Program/Area Name	Reviewed By	Comments
Region:	14	Mike Riff	No objections to issuance
City:	Corpus Christi	No response	
County:	Nueces	No response	
Toxicology:			
Compliance:			
Legal:			
Comment resolution and/or unresolved issues:			

Process/Project Description

This permit authorizes sources on the West Refinery. The refinery receives purchased and refinery feeds and "cracks" them into gasoline, distillate and lighter products.

The company proposes to construct the following new sources:

Source Name	EPN
Sat Gas #3 Hot Oil Heater	SATGASHTR
Sat Gas 3 Unit Fugitives	F-SATGAS3
Mid-Plant Cooling Tower No. 2	F-S-202
100,000 bbl IFR Tank	IFRTK1
75,000 bbl IFR Tank	IFRTK2
UDEX Fugitives	F-14-UDEX
DHT Fugitives	F-37
NHT/CCR Fugitives	F-39
West Crude Fugitives	F-40
Mid-Crude Fugitives	F-42
Gasoline Blender Fugitives	F-GB
VOC Tank/Loading Fugitives	F-TK-VOC
Site-wide Ammonia Fugitives	SITENH3FUG
MSS Emissions for Sat Gas 3 Unit	MSS

The company also proposes to modify the following existing sources currently authorized by Permit 8803A and move them to Permit 6819A:

Source Name	EPN	Modification
CCR Hot Oil Heater	JJ-4	Increase in firing duty from 90 MMBtu/hr to 123.6 MMBtu/hr (HHV) and decrease in hourly SO_2 allowable emission rate as a result of decreasing maximum hourly sulfur content based on fuel sampling; installation of Selective Catalytic Reduction (SCR) with ammonia injection for NO_x control
Marine Vapor Combustor	VCS-1	Increase in currently permitted naphtha and gasoline throughput; decrease in NO_x and CO allowable emission rates due to update in NO_x and CO emission factors based on recent stack testing; decrease in fuel sulfur content
Tank 11FB408	FB408	Increase in annual throughput and decrease in true vapor pressure of material stored.
Tank 11FB409	FB409	Increase in annual throughput and decrease in true vapor pressure of material stored.
Tank 11FB410	FB410	Increase in annual throughput and decrease in true vapor pressure of material stored.
Tank15FB508	FB508	Increase in annual throughput and decrease in true vapor pressure of material stored.

Source Name	EPN	Modification
Tank 15FB510	FB510	Currently a fixed-roof tank; installation of internal floating roof, mechanical shoe primary seal and rim-mounted secondary seal; increase in annual throughput and true vapor pressure of material stored in the tank after installation of internal floating roof.
Tank 40FB3043	FB3043	Currently a fixed-roof tank; installation of internal floating roof, mechanical shoe primary seal, and rim-mounted secondary seal; increase in annual throughput and true vapor pressure of material stored in the tank after installation of internal floating roof.
Tank 40FB3044	FB3044	Currently a fixed-roof tank; installation of internal floating roof, mechanical shoe primary seal, and rim-mounted secondary seal; increase in annual throughput and true vapor pressure of material stored in the tank after installation of internal floating roof.
Tank 40FB4010	FB4010	Increase in annual throughput and decrease in true vapor pressure of material stored; addition of H_2S emissions to MAERT.
Tank 40FB4011	FB4011	Increase in annual throughput and decrease in true vapor pressure of material stored; addition of H_2S emissions to MAERT.
Tank 40FB4014	FB4014	Currently a fixed-roof tank; installation of internal floating roof, mechanical shoe primary seal and rim-mounted secondary seal; increase in annual throughput and true vapor pressure of material stored in the tank after installation of internal floating roof.
Tank 40FB4015	FB4015	Currently a fixed-roof tank; installation of internal floating roof, mechanical shoe primary seal and rim-mounted secondary seal; increase in annual throughput and true vapor pressure of material stored in the tank after installation of internal floating roof.
Tank40FB4016	FB4016	Currently a fixed-roof tank; installation of internal floating roof, mechanical shoe primary seal and rim-mounted secondary seal; increase in annual throughput and true vapor pressure of material stored in the tank after installation of internal floating roof.
Tank 15FB509	FB509	Currently a fixed-roof tank; installation of internal floating roof, mechanical shoe primary seal and rim-mounted secondary seal; increase in annual throughput and true vapor pressure of material stored in the tank after installation of internal floating roof.

The company also proposes to move the following affected sources from Permit 8803A to Permit 6819A:

Source Name	EPN
43BF1 Boiler	R-201
37BA1DHT Charge Heater	KK-3
37BA2 Stripper Reboiler	KK-3
DDS Charge Heater	DDS-HTRSTK
DDS Fractionator Reboiler	DDS-HTRSTK
42BA1 Crude Heater	A-203
42BA3 Vacuum Heater	A-204
LSG Hot Oil Heater	LSGHTR
54BA1 MX Unit Hot Oil Heater	MX-1
FCCU CO Boiler/Scrubber	AA-4
API Separator Flare	V-8
FCCU Fugitives	F-01
Hydrocracker Fugitives	F-26
Tank 08FB108R1	FB108R1
Tank 08FB109R	FB109R
Tank 08FB142	FB142
Tank 08FB147	FB147

Source Name	EPN
Tank 08FB137	FB137
Tank 11FB402	FB402
Tank 11FB403	FB403
Tank 15FB507	FB507
Tank 40FB3041	FB3041
Tank 40FB4012	FB4012
Tank 40FB4013	FB4013

The following changes were made to the permit special conditions:

Old SC	New SC	Change made
2,3	2-4	Updated federal applicability requirements with new format
4,5	5	Updated truck loading conditions
7-10	6	Updated marine loading conditions
11-12	7-8	Updated marine vapor combustor conditions
13	19	Updated CAM condition to include new control devices
14-15	27-29	Updated stack testing conditions to include new sources
16,18	30-31	Updated 28VHP condition
17		Removed condition because deadline passed
	9-18	Added heater conditions
	20-22	Added FCCU conditions
	23	Added flare conditions
	24,25	Added cooling tower conditions
	26	Added storage tank conditions
	32	Added AVO monitoring condition for fugitive ammonia sources
	34,35	Added federal NSR conditions
	36	Added effective date for new emission limits and special conditions
	37-51	Added MSS conditions
	52	Added recordkeeping summary

In addition, Attachments A, B, and C from Permit 8803A were added to the special conditions.

The new sources and the modified and affected sources being transferred from Permit 8803A to Permit 6819A were added to the MAERT

Pollution Prevention, Sources, Controls and BACT- [30 TAC 116.111(a)(2)(C)]

This section discusses BACT in four parts: 1) new source BACT, 2) modified source BACT, 3) discussion of BACT for affected sources, and 4) discussion of the PBRs that are being consolidated.

BACT for new sources:

Sat Gas #3 Hot Oil Heater (EPN SATGASHTR): NO_x will be controlled to a level less than or equal to 0.01 lb/MMBtu by an SCR. CO will be controlled to a level less than or equal to 10 ppmv at 3% oxygen by a catalyst. Both NO_x and CO will be monitored by CEMS. The ammonia concentration in the vent gas stream will be maintained at less than 10 ppmv. This meets current BACT standards.

Mid-Plant Cooling Tower No. 2 (EPN F-S-202): The cooling tower will be equipped with a drift eliminator that achieves a drift of no more than 0.0005%. It will have a non-contact design and will be monitored daily for benzene and VOC. This exceeds current BACT standards.

Storage Tanks (EPNs IFRTK1 and IFRTK2): These are internal floating roof tanks with capacities of 100,000 barrels and 75,000 barrels. They are drain dry, submerged filled, painted white, and equipped with a vapor-mounted primary seal and a rim-mounted secondary seal. This meets current BACT requirements.

VOC Fugitives (EPNs F-SATGAS3, F-14-UDEX, F-37, F-39, F-40, F-42, F-GB, F-TK-VOC): These fugitive sources are monitored by a combination of the 28VHP program and the 28CNTA program. This exceeds current BACT requirements.

Site-wide Ammonia Fugitives (EPN SITENH3FUG): Ammonia fugitives are monitored by the AVO program. This meets current BACT requirements.

BACT for Modified Sources:

CCR Hot Oil Heater (EPN JJ-4): NO_x will be controlled to a level less than or equal to 0.01 lb/MMBtu by an SCR. CO will be maintained at a concentration less than or equal to 50 ppmv at 3% oxygen. Both NO_x and CO will be monitored by CEMS. The ammonia concentration in the vent gas stream will be maintained at less than 10 ppmv. This exceeds current BACT requirements.

Marine Vapor Combustor (EPN VCS-1): The Marine Vapor Combustor is continuously monitored for temperature and pilot flame. It achieves a VOC destruction efficiency of 99.5%, and it is stack tested. This meets current BACT requirements.

Floating Roof Tanks (EPNs FB408, FB409, FB410, FB508, FB4010. FB4011): These are external floating roof tanks with white or aluminum surfaces. They are equipped with slotted guide poles with gasketed covers, wipes, floats, and sleeves, mechanical shoe primary seals, and rim-mounted secondary seals. This meets current BACT requirements.

Fixed Roof Tanks (EPNs FB510, FB3043, FB3044, FB4014, FB4015, FB4016, FB509): These are currently fixed roof tanks with white or aluminum surfaces that are submerged filled. The company proposes to install internal floating roofs with mechanical shoe primary seals and rim-mounted secondary seals. This meets current BACT requirements.

BACT for affected sources: The affected sources were moved from Permit 8803A to Permit 6819A without modification. Flint Hills currently has a deflex application for Permit 8803A in house at TCEQ. According to the four-step deflex process agreed to by Flint Hills, EPA, and TCEQ, TCEQ is required to ensure that all BACT requirements were met at the time the flexible permit was issued in 1999. BACT was reviewed and approved in 1999. Flint Hills is not proposing any physical modifications or changes in method of operation in this permit amendment. Flint Hills represents that BACT was met during every permit action since the flexible permit was issued.

Permit by Rule No. 103051: This authorized natural gasoline loading of ships and barges. Emissions are controlled by a vacuum-assist loading operation that captures 100% of the vapors and vents them to the Marine Vapor Combustor (EPN VCS-1). This meets current BACT requirements.

Permit by Rule No. 103706: This authorized an increase in the annual loading rate of gasoline from 1,900,000 bbl/yr to 4,000,000 bbl/yr at the marine loading rack. Emissions are controlled by a vacuum-assist loading operation that captures 100% of the vapors and vents them to the Marine Vapor Combustor (EPN VCS-1). This meets current BACT requirements.

Impacts Evaluation - 30 TAC 116.111(a)(2)(J)

Was modeling conducted?	**Yes**	Type of Modeling:	**AERMOD**
Will GLC of any air contaminant cause violation of NAAQS?			**No**
Is this a sensitive location with respect to nuisance?			**No**
[§116.111(a)(2)(A)(ii)] Is the site within 3000 feet of any school?			**No**
Additional site/land use information: NA			

Summary of Modeling Results

The small gasoline increases resulting from the incorporation of the two permits by rule are offset by larger gasoline decreases elsewhere on the site, resulting in overall hourly and annual decreases in gasoline emissions. The sources with gasoline decreases are closer to the property line than the Marine Vapor Combustor, so the net result will be a decrease in gasoline impacts.

In addition, the project resulted in ammonia increases from the installation of SCRs on the NHT Charge Heater and the Sat Gas #3 Hot Oil Heater. SCREEN3 modeling of the ammonia increases yielded a total impact of 13.69 µg/m³, which is less than ten percent of the hourly ESL of 170 µg/m³. Health impacts are acceptable.

PM_{10}, $PM_{2.5}$, and NO_x increases were evaluated for compliance with the 24-hour PM_{10} NAAQS, the 24-hour $PM_{2.5}$ NAAQS, and the 1-hour and annual NO_2 NAAQS. Screen modeling was performed by Flint Hills using AERMOD in refined screening mode and approved by Javier Rosa of the Air Dispersion Modeling Team. Modeling of the NO_x increases yielded a 1-hour NO_2 impact of 0.9 µg/m³ and an annual NO_2 impact of 0.1 µg/m³, which are below the 1-hour de minimis level of 7.5 µg/m³ and the annual de minimis level of 1 µg/m³. Modeling of the PM_{10} increases yielded a 24-hour PM_{10} impact of 1.1 µg/m³, which is less than the 24-hour de miminis level of 5 µg/m³. Modeling of the $PM_{2.5}$ increases yielded a 24-hour $PM_{2.5}$ impact of 1.1 µg/m³ and an annual $PM_{2.5}$ impact of 0.1 µg/m³, which are below the 24-hour de minimis level of 1.2 µg/m³ and the annual de minimis level of 0.3 µg/m³. The PM_{10}, $PM_{2.5}$, and NO_x increases will not cause or contribute to an exceedance of any NAAQS.

New guidance on use of the $PM_{2.5}$ SIL has come out based on the fact that the SIL may not be accurate and use of the SIL could cause an exceedance of the $PM_{2.5}$ standard. Because of this, a demonstration has to be made that the standard minus the background concentration obtained from a representative monitor is greater than the SIL. If this is true, the SIL can be utilized. Maximum background concentrations of 23.7 µg/m³ (24-hr) and 9.4 µg/m³ (annual) were obtained from the EPA AIRS Monitor 483550034. The 24-hr standard of 35 µg/m³ minus the background concentration of 23.7 µg/m³ is equal to 11.3 µg/m³ which is greater than the SIL of 1.2 µg/m³ and therefore the 24-hr SIL can be utilized. The annual standard of 12.0 µg/m³ minus the background concentration of 9.4 µg/m³ is equal to 2.6 µg/m³ which is greater than the annual SIL and therefore the annual SIL can be utilized. The $PM_{2.5}$ project increases do not pose a significant deterioration of the NAAQS.

Permit Concurrence and Related Authorization Actions

Is the applicant in agreement with special conditions?	**Yes**
Company representative(s):	**Daren Knowles**
Contacted Via:	**Phone/Email**
Date of contact:	**March 5, 2014**
Other permit(s) or permits by rule affected by this action:	**Yes**
List permit and/or PBR number(s) and actions required or taken:	**Several sources were transferred from Permit 8803A to Permit 6819A. Special Condition 36 requires Flint Hills to submit a permit alteration for Permit 8803A within 90 days of issuance of this permit action to remove the transferred sources from the permit. Permit by Rule Nos. 103051 and 103706 were incorporated into the Permit 6819A and voided.**

Tom Cumbie 5-23-2014 Kim Mydlo 05/23/14

Project Reviewer Date Team Leader/Section Manager/Backup Date

Magee, Melanie

From: Taylor, Curtis <Curtis.Taylor@fhr.com>
Sent: Thursday, November 05, 2015 1:32 PM
To: Magee, Melanie
Cc: Robinson, Jeffrey
Subject: RE: Receipt of Request for a Rescission of the EPA Issued GHG Step 2 PSD Permit: PSD-TX-6819A-GHG
Attachments: WDCP MSS Emissions.pdf

Melanie,

On behalf of Flint Hills Resources Corpus Christi, LLC ("FHR"), I am providing the following response to your clarification request pertaining to FHR's request to rescind EPA Issued GHG Step 2 PSD Permit: PSD-TX-6819A-GHG.

The MSS emissions cap included in TCEQ Permit 6819A for Source Name "Planned MSS Emissions" was increased as part of the amendment to reflect the MSS emissions generated by the West Domestic Crude Project (WDCP). GHG emission increases for MSSFUGS-DC were calculated based on the same operational assumptions used to calculate WDCP MSS emission increases reflected in Permit 6819A. Therefore, all of the activities authorized under EPN MSSFUGS-DC were also authorized under TCEQ Permit 6819A through increases in the MSS emission caps for Source Name "Planned MSS Emissions." I have attached a summary table of the WDCP MSS increases that were added to TCEQ Permit 6819A. Note that some of the WDCP MSS activities reflected in the summary table did not result in GHG emission increases or were consolidated in the GHG MSS calculations and, therefore, were not individually addressed in the GHG permit application under EPN MSSFUGS-DC.

Please contact me if you require additional information. Thank you.

Curtis Taylor

From: Magee, Melanie [mailto:Magee.Melanie@epa.gov]
Sent: Thursday, October 29, 2015 3:55 PM
To: Taylor, Curtis
Cc: Robinson, Jeffrey
Subject: RE: Receipt of Request for a Rescission of the EPA Issued GHG Step 2 PSD Permit: PSD-TX-6819A-GHG

Curtis,

In my review of the referenced Flint Hills rescission request, I have matched most of the EPA emission point numbers (EPN) with the associated TCEQ EPNs from TCEQ permit 6819A. The remaining unmatched EPA EPN is for the work practice standards associated with EPN MSSFUGS-DC. The EPA permit states that this emission point is for GHG emissions from vacuum truck loading, tank degassing and tank refilling. I would like to request additional information to clarify the specific TCEQ EPNs that are associated with the EPA emission point number MSSFUGS-DC.

Thank you in advance for your assistance.
Melanie

From: Magee, Melanie
Sent: Tuesday, October 27, 2015 3:31 PM
To: 'Valerie.Pompa@fhr.com'

Cc: 'Curtis.Taylor@fhr.com'; Robinson, Jeffrey; Olszewski, Joshua; Gerro, Jan
Subject: Receipt of Request for a Rescission of the EPA Issued GHG Step 2 PSD Permit: PSD-TX-6819A-GHG

Ms. Pompa:

Today, we received a copy of your request for a rescission of the EPA issued GHG Step 2 PSD permit for the Flint Hills Resources Corpus Christi, Corpus Christi West Refinery-Domestic Crude Project. We will begin our review of your request and will notify you if more information is needed. If you have any questions, please feel free to email or contact me.

Thanks, Melanie

Melanie Magee
Environmental Engineer
Air Permits Section (6PD-R)
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue
Dallas, Texas 75202
(214) 665-7161

West Domestic Crude Project
Routine Start-up/Shutdown/Maintenance Fugitive Emissions
Emissions Summary

Event	NOx Emission Rates (ton/yr)	CO Emission Rates (ton/yr)	SO2 Emission Rates (ton/yr)	PM Emission Rates (ton/yr)	PM_{10} Emission Rates (ton/yr)	VOC Emission Rates (ton/yr)	H_2S Emission Rates (ton/yr)
Equipment Openings		0.0004				0.10	0.001
PAN emissions						0.12	
Vacuum Truck Loading	0.21	0.14	0.06	0.003	0.00002	0.09	
Frac Tanks						0.02	
Tank Landings (Product Changes)	0.05	0.03	0.00	0.001	0.00000	0.38	
Tank Degassing to Control	0.56	0.37	0.01	0.01	0.0001	1.02	
Tank Refilling After Degassing	0.05	0.03	0.00	0.001	0.00000	1.91	
Total	**0.87**	**0.57**	**0.07**	**0.02**	**0.0001**	**3.64**	**0.001**