TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

NOTICE OF APPLICATION AND PRELIMINARY DECISION
FOR AIR QUALITY PERMITS

AIR QUALITY PERMIT NUMBERS 38754, PSDTX324M15, AND GHGPSDTX211

APPLICATION AND PRELIMINARY DECISION. Valero Refining-Texas, L.P., Post Office Box 9370, Corpus Christi, Texas 78469-9370, has applied to the Texas Commission on Environmental Quality (TCEQ) for an amendment to State Air Quality Permit 38754, modification to Prevention of Significant Deterioration (PSD) Air Quality Permit PSDTX324M15, and issuance of Greenhouse Gas (GHG) PSD Air Quality Permit GHGPSDTX211 for emissions of GHGs, which would authorize modification to the Valero Corpus Christi Refinery West Plant located at 5900 Up River Road, Corpus Christi, Nueces County, Texas 78407. This application was processed in an expedited manner, as allowed by the commission's rules in 30 Texas Administrative Code, Chapter 101, Subchapter J. The existing facility will emit the following air contaminants in a significant amount: carbon monoxide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less and sulfur dioxide. In addition, the facility will emit the following air contaminants: ammonia and hydrogen sulfide.

The degree of PSD increment predicted to be consumed by the existing facility and other increment-consuming sources in the area is as follows:

Sulfur Dioxide

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
24-hour	68	91
Annual	11	20

Nitrogen Dioxide

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
Annual	23	25

$PM_{2.5}$

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
24-hour	8.9	9
Annual	2.9	4

This application was submitted to the TCEQ on September 30, 2021. The executive director has determined that the emissions of air contaminants from the existing facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and "best available control technology" will be used for the control of these contaminants.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director's preliminary decision, draft permit, and the executive director's preliminary determination summary and executive director's air quality analysis, will be available for viewing and copying at the TCEQ central office, the TCEQ Corpus Christi regional office, and at the Owen R. Hopkins Public Library, 3202 McKinzie Road, Corpus Christi, Nueces County, Texas, beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review at the TCEQ Corpus Christi Regional Office, 500 North Shoreline Boulevard, Suite 500, Corpus Christi, Texas.

INFORMATION AVAILABLE ONLINE. These documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, air quality analysis, and, once available, the executive director's response to comments and the final decision on this application. Access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The public location mentioned above provides public access to the internet. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. http://www.tceq.texas.gov/assets/public/hb610/index.html?lat=27.820555&lng=-97.488333&zoom=13&type=r.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting to the Office of the Chief Clerk at the address below. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all relevant and material or significant public comment. **The response to comments, along with the executive director's decision on the application, will be mailed to everyone who submitted public comments or is on a mailing list for this application. The mailing will also provide instructions for requesting a contested case hearing or reconsideration of the executive director's decision.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. You may request a contested case hearing regarding the portions of the application for State Air Quality Permit Number 38754 and for PSD Air Quality Permit Number PSDTX324M15. There is no opportunity to request a contested case hearing regarding the portion of the application for GHG PSD Air Quality Permit Number GHGPSDTX211. A contested case hearing is a legal proceeding similar to a civil trial in a state district court. A person who may be affected by emissions of air contaminants, other than GHGs, from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; (6) a description of how you use the property which may be impacted by the facility; and (7) a list of all disputed issues of fact that you submit during the comment period. If the request is made by a group or association, one or more members who have standing to request a hearing must be identified by name and physical address. The interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following this notice to the Office of the Chief Clerk, at the address provided in the information section below.

A contested case hearing will only be granted based on disputed issues of fact or mixed questions of fact and law that are relevant and material to the Commission's decisions on the application. The Commission may only grant a request for a contested case hearing on issues the requestor submitted in their timely comments that were not subsequently withdrawn. Issues that are not submitted in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. The executive director may issue final approval of the application for the portion of the application for GHG PSD Air Quality Permit GHGPSDTX211. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn regarding State Air Quality Permit Number 38754 and for PSD Air Quality Permit Number PSDTX324M15, the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application, and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of the State Air

Quality Permit Number 38754 and for PSD Air Quality Permit Number PSDTX324M15 and will forward the application and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www14.tceq.texas.gov/epic/eComment/, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Please be aware that any contact information you provide, including your name, phone number, email address and physical address will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Valero Refining-Texas L.P. at the address stated above or by calling Ms. Meagan Marquard, Superintendent Environmental at (361) 299-8913.

Notice Issuance Date: May 19, 2022

Special Conditions

Permit Numbers 38754, PSDTX324M15, and GHGPSDTX211

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. **(TBD)**.

Throughput Limitations

2. Tank truck loading operations are limited to the following liquids and maximum loading rates: **(12/19)**

Chemical	Hourly Rate (gal/hr)
Kerosene	30,000
Diesel	60,000
Gasoline	98,000
Residual Oils	31,920

3. Marine loading shall comply with the following:

   A. Marine loading with emissions that are controlled with the marine vapor recovery unit (VRU) shall be limited to a maximum of 35,000 bbl/hr. The liquids that are loaded at this rate and controlled with the VRU at this facility are limited to gasoline, natural gasoline, naphtha, cat gasoline, alkylate, and reformate.

   The BT concentrate, mixed xylenes, heartcut, and toluene concentrate may also be loaded into marine vessels with emissions controlled by the VRU, at a rate not to exceed 5,000 bbl/hr. Only one of these products may be loaded at a time.

   B. Marine loading with uncontrolled vapor emissions shall be limited to the following services at the indicated rates:

Liquid	Barge bbl/hr	Ship bbl/hr
Diesel*	8,500	12,500
Kerosene*	5,000	12,500
Gas Oil	6,000	20,000
ATB	6,000	20,000
VTB	6,000	20,000
Slurry	6,000	0
Bunker	6,000	20,000

*Diesel and kerosene shall not be loaded onto ships and barges concurrently.

Loading Controls

4. Operation without visible liquid leaks or spills shall be maintained at all loading or unloading facilities regardless of vapor pressure. This does not apply to momentary dripping associated with the initial connection or disconnection of fittings. Sustained dripping from fittings during loading or unloading operations is not permitted. Any liquid spill that occurs during loading or unloading activities shall be cleaned up immediately to minimize air emissions.

5. Emissions resulting from the tank truck loading of gasoline shall be routed to the Vapor Combustor (Emission Point No. [EPN] TRUCKCOMB) for final abatement. The volatile organic compounds (VOC) emissions from EPN TRUCKCOMB shall not exceed 10 milligrams per liter of gasoline loaded. The vapor combustor combustion temperature shall be maintained at or above 1400˚F (based on a five-minute averaging period) when loading vapors are routed to it. This temperature shall be recorded during loading operations and the records maintained on-site. The vapor combustor operating temperature may be lowered if it has been tested at the lower temperature in accordance with Special Condition (SC) No. 39 to demonstrate compliance with this emission limit. Records associated with this permit condition shall be kept for at least five years. The Vapor Combustion Unit (EPN TRUCKCOMB) shall comply with the following. **(12/19)**

   A. The vapor combustor shall be operated with no visible emissions and have a constant pilot flame during all times waste gas could be directed to it. The temperature of the combustion chamber shall be continuously monitored when loading vapors are routed to it. The time, date, and duration of any drop of temperature below 1400°F shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated or have a calibration check performed at a frequency in accordance with, the manufacturer's specifications.

   B. Pilot and make-up fuel for the vapor combustor shall be pipeline-quality, sweet natural gas containing no more than 5 grains of total sulfur per 100 dry standard cubic feet.

   C. The control device shall not have a bypass. 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 that the position of the valves and the condition of the car seals prevent flow out the bypass.

      A bypass does not include authorized analyzer vents, highpoint bleeder vents, low point drains, or rupture discs upstream of pressure relief valves if the pressure between the disc and relief valve is monitored and recorded at least weekly. A deviation shall be reported if the monitoring or inspections indicate bypass of the control device when it is required to be in service.

6. All tank trucks loading gasoline at this facility shall be leak-tight tested a minimum of once a year using the method described in the U.S. Environmental Protection Agency (EPA) regulations in Title 40 Code of Federal Regulations Part 63 (40 CFR Part 63), Subparts A and R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations). **(12/19)**

7. All tank truck loading of residual oils, kerosene and diesel shall be conducted using a submerged fill pipe or using a discharge point no higher than 6 in. above the bottom of the cargo tank. **(12/19)**

8. The marine VRU shall limit VOC emissions from EPN VRU to 5 mg/l of liquid loaded.

9. All marine loading emissions of liquids with vapor pressures greater than 0.5 pound per square inch, absolute (psia) must be vented to the VRU.

10. A vacuum of at least one-inch water column shall be established downstream of the dock pressure control valve prior to commencing marine loading. A vacuum shall also be established on the barge or ship being loaded if possible. The vacuum shall be maintained during loading and monitored continually or an alarm activated if the vacuum is not maintained.

11. The VRU VOC concentration as measured by the continuous emission monitor specified in SC No. 40 shall not exceed 7,621 parts per million (ppm) over any one-hour period while the marine loading emissions are being vented. If the reading exceeds this limit, marine loading shall be secured, the Texas Commission on Environmental Quality (TCEQ) Corpus Christi Regional Office notified, and the cause determined and corrected before loading resumes.

Combustion Controls

12. Flares shall be designed and operated in accordance with the following requirements: **(01/21)**

    A. The flare system(s) shall be designed such that the combined vent gas, assist air, and/or total steam to each flare meets the 40 CFR § 63.670 specifications for minimum combustion zone net heating value and maximum tip velocity at all times that emissions may be directed to the flare for more than 15 minutes. Flared gas actual exit velocity, vent gas net heating value, and flared gas combustion zone net heating value shall be determined in accordance with 40 CFR §63.670(k), §63.670(l), and §63.670(m) on a 15-minute block average and recorded at least once every 15 minutes.

       If the flare actively receives perimeter assist air, it shall be operated to meet the 40 CFR §63.670 specifications for minimum net heating value dilution parameters.

    B. The flare(s) shall be operated with pilot flame(s) present at all times vent gas may be directed to the flare(s). The pilot flame(s) shall be continuously monitored by a thermocouple, infrared monitor, or ultraviolet monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, 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, demonstrated and recorded per the requirements of §63.670(h).

    D. The permit holder shall install flow monitors that continuously measure, calculate and record the total volumetric vent stream flow rate (including waste gas, purge gas, supplemental gas, and sweep gas), and shall install a monitoring system capable of determining the concentration of individual components in the flare vent gas or the net heating value of the flare vent gas. The flow monitor sensor and analyzer sample points shall be installed in the vent stream such that the total vent stream to the flare is measured and analyzed.

If one or more gas streams that combine to comprise the total flare vent gas flow are monitored separately for net heating value and flow, the 15-minute block average net heating value shall be determined separately for each measurement location and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute block average net heating value of the cumulative flare vent gas.

If assist air or assist steam is used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the total volumetric flow rate of assist air and/or assist steam used with the flare.

If pre-mix assist air and/or perimeter assist are used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of premix assist air and/or perimeter assist air used with the flare. Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates.

Perimeter assist air includes all air assist except premix assist air. Premix assist air includes any air intentionally entrained in center steam.

Assist air includes premix assist air and perimeter assist air, but does not include the surrounding ambient air.

The monitors shall be calibrated or have a calibration check performed as specified in Table 13 of the appendix to 40 CFR 63, Part CC to meet the following accuracy specifications: the vent flow monitor shall be ±20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second) ±5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second), all other gas flow monitors shall be ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute) whichever is greater, temperature monitor shall be ±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater, and pressure monitor shall be ±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater. For purposes of this permit, a calibration check means, at a minimum, using a second device or method to verify that the monitor is accurate as specified in the permit.

Calorimeters shall have an accuracy of at least ±2% of span and be calibrated, installed, operated, and maintained in accordance with manufacturer recommendations and as specified in Table 13 of the appendix to 40 CFR 63, Part CC, to continuously measure and record the net heating value of the vent gas sent to the flare, in British thermal units/standard cubic foot of the gas.

For determination of net heating value by gas chromatograph, the minimum accuracy shall be as specified in Performance Specification 9 of Part 60, appendix B. Composition monitoring instruments shall be calibrated, installed, operated, and maintained in accordance with manufacturer recommendations and as specified in 40 CFR §63.671(e) and Table 13 of 40 CFR Pt. 63, Subpart CC. Individual component properties specified in Table 12 of Subpart CC shall apply to net heating value calculations.

E. Quality assured (or valid) data must be generated during periods that flare is operating. 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 flare operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

F. Hourly mass emission rates shall be determined and recorded using the monitoring data collected pursuant to paragraph D of this Special Condition and the emission factors specified in the permit application PI-1 dated March 31, 2011.

G. The Acid Gas Flare (EPN 135) is not authorized for routine emissions or for planned maintenance, startup, and shutdown (MSS) emissions.

13. The American Petroleum Institute (API) Separator Combustor shall achieve at least 98 percent destruction efficiency. The vapor combustor combustion temperature shall be maintained at or above 1600˚F (based on a five-minute averaging period) when the separator is in service. This temperature shall be recorded and the records maintained on-site. The vapor combustor operating temperature may be lowered if it has been tested at the lower temperature in accordance with SC No. 38 to demonstrate compliance with this emission limit. Records associated with this permit condition shall be kept for five years.

A back-up carbon adsorption system (CAS) is a means of control equivalent to the API Separator Combustor for compliance with the preceding paragraph of this special condition. When used as back-up control, the CAS shall meet the following requirements:

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

B. The CAS shall be sampled downstream 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:

(1) The CAS systems equipped with an upstream liquid scrubber may be sampled once every 12 hours of CAS run time to determine breakthrough.

(2) Sampling frequency 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.

(3) 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.

C. The method of VOC sampling and analysis shall be by detector meeting the requirements of SC No. 52. **(02/18)**

D. Breakthrough is defined as the highest measured VOC or benzene concentration at or exceeding 100 ppmv or 5 ppmv, respectively, 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 twenty-four hours. 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 available to replace spent carbon canisters such that replacements can be done in the above specified time frame.

E. Records of CAS monitoring shall include the following:

(1) Sample time and date.

(2) Monitoring results (ppmv).

(3) Canister replacement log.

F. Single canister systems are allowed if the time the carbon canister is in service is limited to no more than 30 percent 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.

G. 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.

14. No visible emissions are allowed from the heaters.

15. The permittee shall operate a continuous hydrogen sulfide (H_2S) monitoring instrument in the fuel feed line header for all fired units with a firing rate greater than 40 MMBtu/hr to continuously monitor a representative sample of fuel gas for H_2S content. The instrument shall be installed and operated according to the specifications set out in 40 CFR § 60.105. These gases shall have a maximum H_2S concentration of 0.054 grain per dry standard cubic foot (dscf) on an hourly average. The Vacuum Unit Heater (EPN 74) may also be fired with vacuum off-gas having a maximum H_2S concentration of 0.10 grain/dscf on an hourly average.

16. Heater, boiler, and reboiler emissions of ammonia (NH_3), carbon monoxide (CO), hydrogen sulfide (H_2S), nitrogen oxide (NO_x), Particulate matter (PM), PM ≤ 10 microns diameter (PM_{10}), PM ≤ 2.5 microns diameter ($PM_{2.5}$), and volatile organic compounds (VOC) shall meet the following specifications: **(TBD)**

EPN	Facility	NO_x 1-hr block average (lb/MMBtu)	NO_x 3-hr block average (lb/MMBtu)	NO_x daily 365 rolling average (lb/MMBtu)	NO_x Compliance Method
162	38-H-01/02/03	0.06	--	0.060	CEMS
1	Crude Heater	0.06	--	0.060	CEMS
74	Vacuum Unit Heater	0.06	0.060	--	stack test
150	47-H-01/02/03/04	0.06	0.060	--	stack test
152	49-H-01/02/03/04	0.07	--	0.070	CEMS
153	Boiler 30-B-02	--	--	0.080	CEMS
172	RSU Heater	0.06	0.060	--	stack test
49H90	C7 Splitter Reboiler	0.04	--	0.040	CEMS
114	Desalter Heater	0.040	0.040	--	stack test
115	12-H-01A/B	0.06	0.060	--	stack test
116	HDS Heavy Oil Preheater	0.12	--	--	
117	Alky Fract Reboiler	0.036	--	0.036	CEMS
118	13-H-01A/B/C	0.06	--	0.060	CEMS

EPN	Facility	NO_x 1-hr block average (lb/MMBtu)	NO_x 3-hr block average (lb/MMBtu)	NO_x daily 365 rolling average (lb/MMBtu)	NO_x Compliance Method
119	Sulften Heater	0.12	--	--	
120	Butamer Heater	0.12	--	--	
195	GD Charge Heater	0.035	--	0.035	CEMS
30-B-04	Boiler 30-B-04	0.015	--	0.015	CEMS
30-B-05	Boiler 30-B-05	0.015	--	0.015	CEMS

EPN	Facility	CO 1-hr block average
162	38-H-01/02/03	0.05 lb/MMBtu
1	Crude Heater	0.05 lb/MMBtu
74	Vacuum Unit Heater	0.05 lb/MMBtu
150	47-H-01/02/03/04	0.03 lb/MMBtu
152	49-H-01/02/03/04	0.03 lb/MMBtu
153	Boiler 30-B-02	--
172	RSU Heater	0.05 lb/MMBtu
49H90	C7 Splitter Reboiler	0.05 lb/MMBtu
114	Desalter Heater	0.037 lb/MMBtu
115	12-H-01A/B	0.05 lb/MMBtu
116	HDS Heavy Oil Preheater	0.016 lb/MMBtu
117	Alky Fract Reboiler	0.016 lb/MMBtu
118	13-H-01A/B/C	0.05 lb/MMBtu
119	Sulften Heater	0.016 lb/MMBtu
120	Butamer Heater	0.016 lb/MMBtu
195	GD Charge Heater	100 ppmv (3% O_2)
30-B-04	Boiler 30-B-04	50 ppmv (3% O_2)
30-B-05	Boiler 30-B-05	50 ppmv (3% O_2)

EPN	Facility	VOC lb/MMBtu	PM/PM_{10} /$PM_{2.5}$ lb/MMBtu
30-B-04	Boiler 30-B-04	0.0053	0.0075
119	Sulften Heater	0.0053	0.0075
30-B-05	Boiler 30-B-05	0.0053	0.0075

EPN	Facility	H_2S in fuel gas lb/MMBtu	NH_3 lb/MMBtu
30-B-04	Boiler 30-B-04	87 ppmv	10 ppmv
119	Sulften Heater	87 ppmv	10 ppmv
30-B-05	Boiler 30-B-05	87 ppmv	10 ppmv

During reduced-load operations for heaters or boilers equipped with CO CEMS, the emission limitations in the above table for CO shall not apply. Reduced-load operation means the operation of a heater or boiler at a firing rate of no greater than 50% of the maximum rated heat duty of the heater or boiler and not during planned MSS. The time and duration of each of each heater or boiler non-routine operation shall be recorded. Additionally, during each non-routine operation the rates of CO shall be calculated from a boiler or heater's CEMS data to demonstrate that MAERT emission limits are not exceeded. Records shall be maintained at the plant site for a period of five years. **(04/22)**

17. Heaters and boilers are prohibited from burning or combusting fuel oil. For purposes of this paragraph, fuel oil is predominately in the liquid phase at the point of combustion with a sulfur content of greater than 0.05% by weight. **(08/16)**

18. Upon request by the Executive Director of the TCEQ, the EPA, or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel(s) utilized in these facilities or shall allow air pollution control agency representatives to obtain a sample for analysis.

19. The Desalter Heater (EPN 114) shall comply with the following: **(04/22)**

    A. The desalter heater shall only be fired with natural gas and fuel gas and the firing rate shall not exceed 99 MMBtu/hr on an annual basis (12-month rolling period) and short-term basis.

    B. The natural gas and fuel gas shall be sampled every 6 months to determine the net heating value. Test results from the fuel supplier may be used to satisfy this requirement.

    C. The permit holder shall install and operate a fuel flow meter to measure the gas fuel usage for the desalter 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. The 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.

    D. Quality assured (or valid) data must be generated when the desalter heater is operating. 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 desalter heater operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Sulfur Recovery Units (SRUs) and HOC Scrubber

20. The coke burn-off non-sulfate particulate matter (PM) emissions may not exceed 0.57 pound per 1,000 pounds of coke burn-off. The HOC scrubber sulfuric acid mist (a subset of total PM) emissions shall not exceed 0.35 pound per 1,000 pounds of coke burn-off.

    Particulate emissions from the HOC shall not exceed one (1) pound per 1,000 pounds of coke burned (front half only according to Method 5B or 5F, as appropriate), measured as a one-hour average over three performance test runs. **(08/16)**

21. The pH of the HOC scrubber circulating caustic solution shall be continually monitored and be maintained at a level between 6.0 and 9.0 by the addition of fresh caustic solution as required. The pH shall be recorded at least hourly, and the records maintained at the plant site for a period of five years. These records shall be made available for inspection by the Executive Director of the TCEQ or his designated representative.

22. The minimum sulfur recovery efficiency for the SRU/Sulften and SRU/Scot shall be 99.8 percent. The sulfur recovery efficiency shall be determined by calculation as follows: **(01/21)**

    Efficiency = (S recovered)*(100) / (S acid gas)

    Where:

Efficiency	=	sulfur recovery efficiency, percent
S recovered	=	(S acid gas - S stack), pounds per hour (lb/hr)
S acid gas	=	sulfur in acid gas stream, lb/hr
S stack	=	sulfur in incinerator stack, lb/hr

    The sulfur recovery efficiency shall be demonstrated for each calendar day (24-hour period) by a mass balance calculation using data obtained from the incinerator stack sulfur dioxide monitor and sulfur production records. Records and copies of the compliance calculations shall be maintained.

23. Acid gas must be routed to a properly operating SRU train. All SRU trains shall normally be operated when acid gas is being produced to maintain the maximum redundant sulfur capacity. The TCEQ Regional Office shall be notified within 72 hours if any SRU train is not fully operational. The notification shall include a description of the problem, the estimated loss of capacity, actions required to correct the problem, and when the line is expected to be fully operational.

    In the event that the Sulften/Scot unit is not operating properly, immediate steps shall be taken to correct the improper operation and shift the acid gas feeds to another fully operational SRU.

24. The Scot tail gas incinerator shall be operated with no less than 3.0 percent oxygen (O_2) in the incinerator stack and at no less than 1500˚F incinerator firebox exit temperature. The incinerator shall achieve a minimum H_2S destruction efficiency of 99.9 percent or 5 parts per million by volume (ppmv) (corrected to 3 percent excess O_2) reduced sulfur compound exit concentration. If stack testing indicates that a higher temperature or O_2 concentration is necessary to obtain a minimum H_2S destruction efficiency of 99.9 percent or 5 ppmv (corrected to 3 percent excess O_2) reduced sulfur compound exit concentration, then the temperature and O_2 maintained during the stack test will become the new minimum operating limits. The O_2 and temperature requirements do not apply

when performing a stack test on the incinerator in accordance with SC No. 39. The permit holder may request that the operating limits be relaxed with a permit alteration request should stack testing indicate the required emissions control is obtained at the proposed limits.

25. In order to control opacity from the stack of EPN 121, the permittee shall maintain the liquid to the filtering modules at a pressure greater than 45 pounds per square inch (psi) and the flue gas pressure drop across the filtering modules and the cyclolabs at no less than 5 inches of water. Liquid pressure and pressure drop shall be continuously recorded and maintained at the plant site for a period of five years. These records shall be made available for inspection by the Executive Director of the TCEQ or his designated representative.

    The opacity of emissions from the Caustic Scrubber Stack (EPN 121) shall not exceed 20 percent averaged over a six-minute period as determined by a trained observer.

Control Requirements

26. The Oleflex and Naphtha Continuous Catalyst Regenerator (CCR) scrubber liquids shall be sampled at least twice daily (once per shift) for caustic inventory. The pH of the scrubbing liquids in the Oleflex CCR caustic scrubber shall be maintained at 8 pH units or greater. The caustic concentration of the Naphtha Reformer CCR shall be maintained greater than 0.41 weight percent sodium hydroxide (measured as total alkalinity). **(11/20)**

27. The caustic absorber circulation rate for the Naphtha CCR shall be a minimum of 368 gpm. The circulation rate shall be recorded at least hourly, and the records maintained at the plant site for a period of five years. These records shall be made available for inspection by the Executive Director of the TCEQ or his designated representative.

28. Storage tanks are subject to the following requirements. The control requirements specified in paragraphs A through D 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. An internal floating deck or roof or equivalent control shall be installed in all tanks. 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 internal floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

    B. An open-top tank containing a floating roof (external floating roof tank) which uses double seal or secondary seal technology shall be an approved control alternative to an internal floating roof tank 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.

    C. For any tank equipped with a floating roof, the permit holder shall perform the visual inspections and seal gap measurements as specified in 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 seals were inspected and seal gap measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

D. 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.

E. Uninsulated tank exterior surfaces exposed to the sun shall be white or 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 barrels, 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 for tanks shall be calculated using the TCEQ publication titled “Technical Guidance Package for Chemical Sources - Storage Tanks.”

G. Floating roof tanks 23, 26, and 164 shall be equipped with a Pole Sleeve System or equivalent as required by the Storage Tank Emission Reduction Partnership Program (STERPP) Agreement with U.S. EPA, dated May 23, 2001, as listed in Appendix I and Annex A of that agreement. Storage Tank 164 was owned by the Valero Bill Greehey Refinery – West Plant at the time of STERPP Agreement execution and is currently owned by NuStar Energy LP (a non-affiliated company).

29. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration of greater than 1 percent are not authorized by this permit unless authorized on the maximum allowable rates table. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration greater than 1 weight percent are not consistent with good practice for minimizing emissions.

30. All cooling towers except for the Propylene cooling tower (EPN HOC-PP-CT) shall comply with the requirements of paragraphs A-D, and the Propylene cooling tower (EPN HOC-PP-CT) shall comply with the requirements of paragraph E: **(TBD)**

A. The cooling tower water shall be monitored monthly for VOC leakage from heat exchangers in accordance with the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or another air stripping method approved by the TCEQ Executive Director.

B. Cooling water VOC concentrations above 0.08 ppmw indicate faulty equipment. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. Faulty equipment shall be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs.

C. Emissions from the cooling tower are not authorized if the VOC concentration of the water returning to the cooling tower exceeds 0.80 ppmw. The VOC concentrations above 0.80 ppmw are not subject to extensions for delay of repair under this permit condition. The results of the monitoring and maintenance efforts shall be recorded.

D. Cooling water shall be sampled once a week for total dissolved solids (TDS) and once a day for conductivity. Dissolved solids in the cooling water drift are considered to be emitted as total particulate matter (PM) / PM equal to or less than 10 microns in diameter (PM_{10}) / PM equal to or less than 2.5 microns in diameter ($PM_{2.5}$). The data shall result from collection of water samples from the cooling tower feed water and represent the water being cooled in the tower. Water samples should be capped upon collection, and transferred to a laboratory area for analysis. 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]. The analysis method for Conductivity shall be ASTM D1125-95A and SM2510 B. Use of an alternative method shall be approved by the TCEQ Regional Director prior to its implementation.

E. The Propylene cooling tower (EPN HOC-PP-CT) shall be operated and monitored in accordance with the following:

(1) The VOC associated with the Propylene cooling tower (EPN HOC-PP-CT) water shall be monitored monthly with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or an approved equivalent sampling method. The results of the monitoring, cooling water flow rate and maintenance activities on the cooling water system shall be recorded. The monitoring results and cooling water hourly mass flow rate shall be used to determine cooling tower hourly VOC emissions. The rolling 12 month cooling water emission rate shall be recorded on a monthly basis and be determined by summing the VOC emissions between VOC monitoring periods over the rolling 12 month period. The emissions between VOC monitoring periods shall be obtained by multiplying the total cooling water mass flow between cooling water monitoring periods by the higher of the two VOC monitored results.

(2) Each cooling tower shall be equipped with drift eliminators having manufacturer's design assurance of 0.001% drift or less. Drifts eliminators shall be maintained and inspected at least annually. The permit holder shall maintain records of all inspections and repairs.

(3) Total dissolved solids (TDS) shall not exceed 6,000 parts per million by weight (ppmw). 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.

(4) Cooling water shall be sampled at least once per week for TDS.

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

(a) 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.

(b) Alternate sampling and analysis methods may be used to comply with (5)(a) with written approval from the TCEQ Regional Director. If approved by the TCEQ Regional Director, the permit holder shall submit a permit application to incorporate the alternative sampling and analysis method into the permit within 2 months of the date of written approval.

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

(6) 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.

Fugitive Emissions Control

31. Piping, Valves, Flanges, Pumps, and Compressors in VOC Service - Intensive Directed Maintenance - 28 VHP

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment.

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68˚F or (2) the 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), 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.

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 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: the line or valve must have a cap, blind flange, plug, or second valve installed; or 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 permit condition for fugitive emission monitoring, except that a leak is defined as any VOC reading greater than background. Leaks must be repaired within 24 hours 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.

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. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed weekly 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.

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 are 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.

Replaced 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 and compressor 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 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 and compressor 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. Records of the first attempt to repair shall be maintained.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 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. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC §§ 115.352 through 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.

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

32. Pump and compressor seals shall be monitored for fugitive leakage monthly rather than quarterly as specified by SC No. 31. The leak definitions, recordkeeping, and corrective actions of those conditions still apply to these components.

33. In addition to the weekly physical inspection required by Item E of SC No. 31, all accessible valve connectors in gas or vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F through J of SC No. 31.

In lieu of the monitoring frequency specified in the above paragraph, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in the paragraph.

The percent of connectors leaking used in paragraph B shall be determined using the following formula:

$(Cl + Cs) \times 100/Ct = Cp$

Where:

Cl	=	the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.
Cs	=	the number of connectors for which repair has been delayed and are listed on the facility shutdown log.
Ct	=	the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor connectors.
Cp	=	the percentage of leaking connectors for the monitoring period.

Process Piping, Valves, Pumps, and Compressors in H_2S and Hydrogen Fluoride (HF) Service.

34. This condition shall apply to all process streams with greater than 2 weight percent H_2S and all process streams with greater than 0.5 weight percent HF.

    A. Audio, olfactory, and visual checks for H_2S and HF leaks within the operating area shall be made once a shift. **(04/22)**

    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) If immediate repair is not possible, a leak collection or containment system will be used to prevent or minimize the leak or the facility shall be shutdown in an orderly manner until repair or replacement can be made. Containment can include adjustment of bolts, fittings, packing glands, and pump or compressor seals to contain the leak.

        Records shall be maintained of all inspections, leaks noted, repairs, and replacements made. These records shall be maintained at the plant site for a period of five years and shall be made immediately available at the request of TCEQ personnel.

Wastewater Collection and Treatment

35. The wastewater collection and treatment system shall comply with the requirements of this permit and with the requirements for wastewater systems in 40 CFR Part 60, Subparts A and QQQ,

except as described in the following sentence. Components for which construction, modification, or reconstruction has not commenced after May 4, 1987, in the process units that follow, shall comply with the requirements of this permit and with the requirements of applicable State regulations, but are exempt from 40 CFR Part 60, Subparts A and QQQ.

Process Unit	
Heavy Oil Cracker	Vacuum Unit
HDS Unit	HF Alky Unit
SMR Unit	Boilerhouse
Crude Unit	SWS/Amine
SRU/Sulften	Tank Farm

36. The wastewater collection systems which are routed to a control device shall comply with the following requirements: **(TBD)**

A. Process wastewater drains shall be equipped with water seals or equivalent. Lift stations (with the exception of the HOC Gas Plant lift station), manholes, junction boxes, any other wastewater collection system components, conveyance, storage, and treatment system to the biological treatment unit shall be equipped with a closed vent system that routes all organic vapors to an API Separator Combustor or a back-up CAS. The HOC Gas Plant lift station shall be routed to the CAS (EPN CAS-HOCPP).

B. Water seals shall be checked by visual or physical inspection quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls. Water seals shall be restored as necessary within 24 hours. Records shall be maintained of these inspections and of corrective actions taken.

C. The HOC Gas Plant lift station shall vent through a CAS (EPN CAS-HOCPP) consisting of at least two activated carbon canisters that are connected in series.

(1) The CAS shall be sampled every two weeks or at 30 percent of the minimum potential saturation time, whichever is soonest, to determine breakthrough of volatile organic compounds (VOC). The sampling point shall be at the outlet of the initial canister but before the inlet to the second or final polishing canister. Sampling shall be done during routine operation of the lift station when wastewater is being generated by process units.

(2) The VOC sampling and analysis shall be performed using an instrument with a flame ionization detector (FID), or a TCEQ-approved alternative detector. The instrument/FID must meet all requirements specified in Section 8.1 of EPA Method 21 (40 CFR 60, Appendix A). Sampling and analysis for VOC breakthrough shall be performed as follows:

(a) Immediately prior to performing sampling, the instrument/FID shall be calibrated with zero and span calibration gas mixtures. Zero gas shall be certified to contain less than 0.1 ppmv total hydrocarbons. Span calibration gas shall be methane at a concentration within ± 10 percent of 5 ppmv, and certified by the manufacturer to be ± 2 percent accurate. Calibration error for the zero and span calibration gas checks must be less than ± 5 percent of the span calibration gas value before sampling may be conducted.

(b) The sampling point shall be at the outlet of the initial canister but before the inlet to the second or final polishing canister. Sample ports or connections must be designed such that air leakage into the sample port does not occur during sampling.

(c) During sampling, data recording shall not begin until after two times the instrument response time. The VOC concentration shall be monitored for at least 5 minutes, recording 1-minute averages, during the maximum flow rate from the lift station.

(3) Breakthrough shall be defined as the highest 1 minute average measured VOC concentration at or exceeding 100 ppmv or benzene concentration at or exceeding 5 ppmv. 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 24 hours. 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.

(4) Records of the CAS monitoring maintained at the plant site, shall include (but are not limited to) the following:

(a) Sample time and date.

(b) Monitoring results (ppmv).

(c) Corrective action taken including the time and date of that action.

(d) Process operations occurring at the time of sampling.

(5) Alternate monitoring or sampling requirements that are equivalent or better may be approved by the TCEQ Regional Manager. Alternate requirements must be approved in writing before they can be used for compliance purposes.

37. The daily wastewater flow into the wastewater treatment plant shall be monitored and recorded. The rolling 12-month wastewater flow shall be totaled on a monthly basis.

38. The minimum mixed liquor total suspended solids (MLSS) concentration in the aeration basins on a daily average basis shall not be less than 2000 mg/L. The MLSS concentration is the arithmetic average of all samples collected during the 24-hour period. The MLSS concentrations shall be monitored and recorded daily using Method 160.2 (Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020 or Method 2540D (Standard Methods of the Examination of Water and Wastewater, 18th Edition, American Public Health Association).

Compliance Testing

39. 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 all heaters and boilers with firing rates greater than 40 MMBtu/hr, Scot Tail Gas Incinerator (EPN 121 or 121a), Sulften Tail Gas Incinerator (EPN 121 or 121a), Caustic Scrubber (EPN 121), Marine Loading VRU (EPN VRU), and Vapor Combustors (EPNs TRUCKCOMB and 124), to demonstrate compliance with the maximum allowable emissions rate table (MAERT). Sampling shall be performed

upstream and downstream of the SMR condensate stripper vent condenser to demonstrate compliance with SC No. 46. 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. **(02/18)**

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 for40 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 production rate, to set operating parameters and limits to be monitored 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.

B. Air contaminants to be tested from sources:

(1) Air contaminants emitted from the heaters and boilers to be tested for include (but are not limited to) NO_x and CO.

(2) Air contaminants emitted from the caustic scrubber to be tested for include (but are not limited to) sulfur dioxide (SO_2), NO_x, PM (both front and back-half of the sampling train), sulfuric acid, and CO. Stack testing of the Belco Scrubber (EPN 121) shall be accomplished by temporarily routing the Sulften and Scot Tail gas to EPN 121a. The sulfuric acid mist stack sample shall be performed using both TCEQ Method 24 and EPA Method 8. The lower of the two sampling results may be used to demonstrate compliance.

(3) Air contaminants emitted from the Sulften and Scot tail gas incinerators to be tested for include (but are not limited to) SO_2, NO_x, CO, PM (both front and back half of the sampling train), and total reduced sulfur.

(4) Air contaminants emitted from the vapor combustors to be tested for include (but are not limited to) VOC, NO_x, and CO.

(5) Air contaminants to be tested for the SMR condensate stripper vent condenser include methanol.

C. Requests for additional time to perform sampling shall be submitted to the TCEQ Corpus Christi Regional Office. Additional time to comply with the applicable requirements of 40 CFR Part 60 and 40 CFR Part 61 requires the EPA approval. Sampling of air contaminants shall occur as follows:

(1) Air contaminants monitored with a CEMS as specified under SC No. 40 shall be sampled to support CEMS operation as required by that condition.

(2) Sampling of air contaminants not monitored by CEMS under SC No. 40 shall occur as follows:

(a) Within 180 days of the issuance of this permit unless the emission point had been sampled within the last 5 years.

(b) Each emission point shall be sampled within 60 days of achieving maximum operation, not to exceed 180 days after initial operation, if new burners have been installed or if an operational change has been made allowing emissions to increase more than 10 percent greater than determined by the last stack sample.

(c) Each emission point shall be sampled as may be required by the Executive Director of the TCEQ.

D. The facility shall operate at maximum production rates during stack emission testing. Primary operating parameters that enable determination of production rates 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, if an operating parameter as determined in the previous paragraph is greater than that recorded during the test period, stack sampling 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 TCEQ within 60 days after sampling is completed. Sampling reports shall comply with the attached conditions of Chapter 14 of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One copy to the TCEQ Corpus Christi Regional Office.

Continuous Determination of Compliance

40. The holder of this permit shall install, calibrate, and maintain a CEMS to measure and record the in-stack concentration of VOC from the marine VRU; CO, NO_x, and O_2 from the heaters and boilers with firing rates greater than 100 MMBtu/hr; SO_2 and O_2 from the SRU/Sulften Tail Gas Incinerator (exhausts to EPN 121 or 121a); SO_2 and O_2 from the SRU/Scot Tail Gas Incinerator (exhausts to EPN 121 or 121a), and NO_x, CO, O_2, and SO_2 from the Caustic Scrubber (exhausts to EPN 121). The monitoring system shall meet the following section of Requirements for CEMS. **(02/18)**

Requirements for CEMS

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 7, 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, § 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.

(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 once 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 the permit allowable emission rate in pounds/hr at least once every week and cumulative tons per year (TPY) on a 12-month rolling average at least once every month.

D. All monitoring data and quality-assurance data shall be maintained by the source for a period of five years and shall be made available to the TCEQ Executive Director or his designated representative upon request. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. All cylinder gas audit exceedances of ±15 percent accuracy and any CEMS downtime associated with emissions from EPNs 121 and 121a shall be reported to the appropriate TCEQ Regional Director within three days of any downtime, and necessary corrective action shall be taken. If the CEMS downtime for a specific emission point occurs when emissions are not being routed to that stack, that time period shall not be considered reportable CEMS downtime for the purposes of this special condition. Exceedances at other emission points shall be reported in Semiannual Excess Emission Reports. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director.

F. 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.

G. Quality-assured (or valid) data must be generated when each emitting facility 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 that it does not exceed 5 percent of the time (in minutes) that the facility operated over the previous rolling 12-month period. 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.

H. This paragraph applies to the NO_x, SO_2, and O_2 CEMS on the Caustic Scrubber (exhausts to EPN 121) and to the heaters and boilers in listed in SC No. 16 with NO_x CEMS. In addition to the requirements of SC No. 40.A-G., the CEMS shall be installed, certified, calibrated, maintained and operated in accordance with the provisions of 40 CFR §60.13 which are applicable only to CEMs (excluding those provisions applicable only to continuous opacity monitoring systems) and Part 60, Appendices A and F, and the applicable performance specification test of 40 CFR Part 60, Appendix B. With respect to 40 CFR Part 60 Appendix F, in lieu of the requirements of 40 CFR Part 60, Appendix F §§5.1.1, 5.1.3 and 5.1.4, the source must conduct either a RAA or a RATA on each CEMS at least once every three (3) years. The source must also conduct CGA each calendar quarter during which a RAA or a RATA is not performed. **(02/18)**

41. Pollutant concentrations at the outlet from the Caustic Scrubber (exhausts to EPN 121) shall not exceed the following values at dry conditions, zero percent O_2:

Pollutant	Maximum Allowable	Averaging Period
SO_2	50 ppm	1.0 hour
SO_2	50 ppm	7-day rolling average **(04/16)**
SO_2	25 ppm	365-day rolling average **(04/16)**
CO	500 ppm	1.0 hour
NO_x	150 ppm	1.0 hour

Pollutant concentrations at the outlet from the SCOT Stack (EPN 121a) shall not exceed the following values at dry conditions, zero percent O_2:

Pollutant	Maximum Allowable	Averaging Period
SO_2	250 ppm	1.0 hour
CO	332 ppm	1.0 hour
NO_x	50 ppm	1.0 hour

42. The continuous monitoring data will be used to determine violations of the limitations in this permit. For purposes of enforcement, the following averaging periods shall be utilized unless otherwise specified in this permit with respect to a specific emission point and pollutant:

Pollutant	Averaging Period
SO_2	1.0 hour
CO	1.0 hour
H_2S	1.0 hour
Opacity	6.0 minutes
NO_x	1.0 hour

HF Control Measures

43. The HF detection paint shall be used on all potential fugitive sources and possible leak sites. Locations with HF detection paint shall be inspected every shift during the audio, visual, and olfactory checks required by SC No. 34. If leaks are detected, corrective action shall be taken immediately as described in SC No. 34. If there is a problem with HF sensitive paint availability, the holder of this permit shall notify the TCEQ Corpus Christi Regional Office and request additional time for painting or request alternate leak detection methods pending availability of the HF sensitive paint.

44. In the event of an HF release which may have the potential for off-site impacts, the holder of this permit shall implement the procedures outlined in the emergency response plans.

45. There shall be no overhead work in the HF process unit where equipment is being lifted over unprotected vessels or lines without first completing a safe work checklist in accordance with Occupational Safety and Health Administration Process Safety Management rules. The safe work checklist shall be used to ensure that every effort is made to minimize the potential for an accident that would result in loss of integrity of HF-containing equipment.

    The holder of this permit is required to notify the TCEQ Corpus Christi Regional Office no less than eight hours prior to conducting work over unprotected vessels or lines containing more than 5 percent by weight HF.

Miscellaneous

46. The SMR stripper vent condenser shall collect 98 percent of the methanol in the stripper vent on an hourly averaging period. The stripper exhaust gas temperature shall be maintained below that maintained during the most recent stack sample following the initial stack test.

    The condenser exhaust gas temperature shall be continuously monitored and recorded when the stripper is operating. The temperature measurement device shall reduce the temperature readings to an averaging period of six minutes or less and record it at that frequency. 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.

47. Flares: BUP Flare, Main Flare and Ground Flare shall be operated in accordance with the New Source Performance Standards for Petroleum Refineries, 40 CFR Part 60 Subpart Ja. **(04/16)**

48. After December 31, 2008 the maximum allowable emission limit of NO_x from the West Plant Heavy Oil Cracker (HOC) (EPN 121) shall not exceed 37 ppmv (dry, zero percent O_2 basis) on a 365-day rolling average and shall not exceed 74 ppmv (dry, zero percent O_2 basis) on a 7-day rolling average. **(04/16)**

Maintenance, Startup, and Shutdown

49. Planned startup and shutdown emissions due to the activities identified in SC No. 50 are authorized from facilities and emission points identified in Attachment 1, Boiler 30-B-03 (EPN: 163) in Permit 20740, the Xylene Splitter Reboiler Heater 49-H-91 (EPN: 49-H-91) in Permit 20992, emission points identified in SC No. 16 in Permit 106965, and emission points identified in SC No. 25 in Permit 109543, provided the facility and emissions are compliant with the routine emission caps and SC No. 60 of this permit. **(02/14)**

50. This permit authorizes the emissions for the planned MSS activities summarized in the MSS Activity Summary (Attachment 4) attached to this permit. This permit also 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 painting or abrasive blasting, portable control devices identified in SC No. 61, 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 listed in Attachment 1, and (c) does not operate as a replacement for an existing authorized facility.

    Attachment 2 identifies the inherently low emitting MSS activities that may be performed at the refinery. Emissions from activities identified in Attachment 2 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 2 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 3 may be tracked through the work orders or equivalent. Emissions from activities identified in Attachment 3 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 2 or 3 and the emissions associated with it shall be recorded and include at least the following information: **(04/22)**

    A. the process unit at which emissions from the MSS activity occurred, including the emission point number and common name of the process unit;

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

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

    D. the date and time on which the MSS activity occurred;

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. A sum of all hourly MSS emissions shall be kept during all times when MSS activities are occurring to demonstrate that the MAERT hourly MSS Cap is not exceeded.

51. Process units and facilities, with the exception of those identified in SC Nos. 54 (related to Floating Roof Tanks), 55 (related to Fixed Roof Tanks), 57 (related to frac or temporary tanks), and activities listed in Attachment 2, shall operate in accordance with the following requirements during MSS.

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 true vapor pressure (TVP) 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 without depressuring or degassing to a control device. 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 TVP 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 shall be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids with a VOC partial pressure greater than or equal to 0.044 psia at 68°F shall be drained into a closed vessel or to a controlled oily water system, unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid shall 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 TVP 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 following requirements do not apply to fugitive components, pumps, compressors.

(1) For MSS activities identified in Attachment 3, 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, P&ID's, or Turnaround and Inspection [T&I] plans 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, purge gas must have passed through the control device or controlled recovery system for a sufficient period of time in accordance with the applicable site operating procedures 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 SC No. 52. 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 or equal to 10,000 ppmv or 10 percent of the LEL.

(3) Alternatively, the process equipment may filled with a liquid with a VOC vapor pressure less than 0.147 psi while venting to control. If it can be verified that the liquid filled the entire process equipment or vessel, no sampling is necessary. If not, the VOC concentration shall be verified to be less than 10,000 ppmv or 10 percent of the LEL using an instrument meeting the requirements of SC No. 52 while purging to control immediately after draining the liquid from the system. The locations and/or identifiers where the liquid enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded (PFDs, P&IDs, or T&I plans may be used to demonstrate compliance with the requirement).

E. Equipment containing materials with VOC TVP 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 lb of air contaminants to be vented to atmosphere during each shutdown or startup of a piece of equipment, as applicable.

All instances of venting directly to atmosphere per SC No. 51.D 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 logs, or equivalent for those planned MSS activities identified in Attachment 3. **(02/18)**

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

A. The 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. The calibration gas used and its concentration, and the vapor to be sampled and its approximate response factor (RF), shall be recorded. If the RF of the VOC (or mixture

of VOCs) to be monitored is greater than 2.0, the VOC concentration shall be determined as follows:

VOC Concentration = Concentration as read from the instrument*RF

(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 greatest VOC concentration recorded. This 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 a lower explosive limit detector.

(1) The detector shall be calibrated monthly with a certified pentane gas standard at 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 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 25 percent of the LEL for pentane may be used for calibration and functionality tests provided that the LEL response is within 95 percent of that for pentane.

D. For measuring benzene breakthrough on Carbon Adsorption Systems in SC No. 61.A.(4), a portable gas chromatograph using a flame ionization detector or photo ionization detector may be used. Alternatively a photo-ionization detector equipped with a benzene separation tube consistent with manufacturer requirements may be used. The monitor shall have the sensitivity and specificity to quantify low level benzene concentrations. The monitor device shall be calibrated within 24 hours of use with a certified calibration gas containing ~5 ppm benzene. Records of the calibration date/time and calibration result shall be maintained.

53. 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 New Source Review (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 within 24 hours 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.

54. This permit authorizes emissions from the storage tanks identified in Attachment 1 during planned floating roof landings. Tank floating roofs may only be landed for changes of tank service or tank inspection/maintenance as identified in the permit application, except when the VOC vapors below the floating roof are routed to a control device or a controlled recovery system while the roof is landed. Tank change of service includes landings to accommodate seasonal RVP spec changes and landings to correct off-spec material that cannot be blended into finished product tanks. 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 two 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 during this process.

    B. If the VOC TVP 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. Floating roof tanks with liquid capacities less than 100,000 gallons may be degassed without control if the VOC TVP 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 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.

(3) A volume 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 volume measurement shall not include any make-up air introduced into the control device or recovery system. The VOC sampling and analysis shall be performed as specified in SC No. 52.

(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 VOC concentration shall be recorded once an hour.

(6) Degassing must be performed every 24 hours unless there is no standing liquid in the tank or the VOC TVP 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 TVP less than 0.02 psia. These criteria may be demonstrated in any one of the following ways.

(1) Low VOC TVP liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC TVP 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 TVP may be estimated based on this information and engineering calculations.

(2) If water is added or sprayed into the tank to remove standing VOC, one of the following must be demonstrated:

(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 Part 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 MSS SC No. 52.

(3) No standing liquid verified through visual inspection.

The permit holder shall maintain records to document the method used to release the tank.

D. Tanks shall be refilled as rapidly as practicable until the roof is off its legs unless the vapor space is routed to control during refilling except as required by SC No. 69.

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 and time of 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 TVP liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC TVP to <0.02 psi,

(e) if there is liquid in the tank, VOC TVP of liquid, start and completion of uncontrolled degassing, and total volumetric flow,

(f) refilling commenced, liquid filling the tank, and the 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.

55. Fixed-roof storage 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 TVP less than 0.02 psia. This shall be verified and documented through one of the criteria identified in MSS SC No. 52.C. Storage tanks manways may be opened without emission controls when there is standing liquid with a VOC TVP greater than 0.02 psia as necessary to set up for degassing and cleaning. One manway may be opened to provide access to the tank when necessary to allow access to remove or de-volatilize the remaining liquid. The emission control system shall meet the requirements of SC Nos. 54.B.(1) through 54.B.(5) and records maintained per SC No. 54.E.(3)c through 54.E.(3)e, and 54.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.

56. The following requirements apply to vacuum and air mover truck operations at this site:

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

B. 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 TVP 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 TVP 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 with a control device other than an engine or oxidizer, VOC exhaust concentration upon commencing each transfer, at the end of each transfer, and as required by SC No. 61, measured using an instrument meeting the requirements of MSS SC No. 52.

(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 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 TVP 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 SC Nos. 56.A through 56.D do not apply.

57. 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. This requirement also does not apply to frac tanks which are heated for the purpose of mixing liquids with VOC TVP less than 0.10 psi at 95°F. **(03/16)**

B. These tanks/vessels must be covered and equipped with fill pipes that discharge within 6 inches of the tank/vessel bottom.

C. These requirements do not apply to vessels storing less than 25 barrels 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 TVP 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 TVP less than 0.10 psi at 95F, 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.

58. The term "true vapor pressure (TVP)" is used in lieu of the term "partial pressure" in this permit.

59. 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.

60. All permanent facilities must comply with all operating requirements, limits, and representations in the permits identified in Attachment 1 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. Heaters, boilers, and furnaces are exempt from NO_x and CO operating requirements identified in other special conditions this permit during planned startup and shutdown if the following criteria are satisfied. This exemption does not include NO_x 365-day rolling average limits. **(08/16)**

(1) The routine maximum allowable emission caps are not exceeded.

(2) Except as noted in SC 60 A(4) below the startup period does not exceed 8 hours in duration 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.

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

(4) Startup times exceeding 8 hours for specific facilities are allowed as identified below: **(04/22)**

Heater, Boiler, or Furnace FIN	EPN	Maximum Hours Allowed for Startup of each FIN
12-H01A and 12-H01B	115A and 115B	48
13-H-01A, 13-H-01B, and 13-H-01C	118	28
31-H-01	117	12
38-H-01, 38-H-02,38-H-03	162	45
47-H-03 and 47-H-04	150	10
48-H-01	151	12
49-H-01, 49-H-02, 49-H-03, 49-H-04	152	16

Heater, Boiler, or Furnace FIN	EPN	Maximum Hours Allowed for Startup of each FIN
52-H-01	195	24

B. The limits identified below apply to the operations of the specified facilities during startup and shutdown. All other routine operating limitations apply during planned startup and shutdown.

(1) The HOC startup period shall not exceed 86 hours and the hourly average CO concentration during this period shall not exceed 1200 ppmvd corrected to zero percent O_2. All HOC emissions during startup are in the MSS emission caps.

(2) The sulfur recovery requirements and SRU tail gas incinerator sulfur dioxide concentration limits in SC Nos. 22 and 41 do not apply during SRU startup. Operation in the hot standby mode shall be minimized. The SRU tailgas incinerator shall be operated in accordance with SC No. 24 during this period. A SRU incinerator shall not operate in this mode for more than 72 hours in any rolling 12 month period.

(3) Paragraph (2) of this condition does not apply when SRU vent gasses from a TGI are routed through the HOC caustic scrubber prior to being discharged to the atmosphere. This paragraph applies instead. The HOC caustic scrubber shall be monitored with a SO_2 CEMS.

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

61. 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 downstream 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) The CAS systems equipped with an upstream liquid scrubber may be sampled once every 12 hours of CAS run time to determine breakthrough.

(b) Sampling frequency 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.

(c) 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 SC No. 52.

(4) Breakthrough is defined as the highest measured VOC or benzene concentration at or exceeding 100 ppmv or 5 ppmv, respectively, 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 twenty-four hours. 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 available 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 percent 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 and Vapor Combustion Units (VCUs) **(04/22)**

(1) The thermal oxidizer or VCU six minute average 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 or VCU exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer or VCU. 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 ±2.5ºC.

(3) As an alternative to 61.B.(1) of this condition, the thermal oxidizer or VCU may be tested to confirm a minimum 99 wt percent destruction efficiency. The results of the test will be used to determine the minimum operating temperature and residence time. Stack Test must have been performed within the last 12 months. Stack VOC concentrations and flow rates shall be measured in accordance with applicable United

States Environmental Protection Agency (EPA) Reference Methods. A copy of the test report shall be maintained with the thermal oxidizer or VCU and a summary of the testing results shall be included with the emission calculations.

(4) As an alternative to 61.B.(1)-(2) of this condition, the thermal oxidizer or VCU may be equipped with continuous VOC monitors (inlet and outlet). The VOC monitors shall be calibrated and maintained according to SC No. 52, except 52.C. In order to demonstrate compliance with this requirement, inlet VOC and outlet VOC concentrations and flows shall be measured at least every 15 minutes and this information used to determine inlet and outlet VOC mass rates on an hourly basis to confirm a minimum of 99 percent destruction efficiency or an exhaust concentration not greater than 20 ppmv.

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 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 SC No. 52 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

(1) The heating value and velocity requirements in 40 CFR 60.18 shall be satisfied during operations authorized by this permit.

(2) The flare 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 thermal couple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications.

(3) Each flare shall be equipped with one of the following:

(a) Operation and maintenance of a flare gas recovery system.

(b) A continuous flow monitor and composition analyzer that provides a record of the flare gas flow and composition of either the total VOC or heating value of the flare gas.

The flow monitor and analyzer sample point shall be installed as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow and composition shall be recorded each hour. The flow monitors shall be calibrated on an annual basis to meet the following accuracy specifications: the flow monitor must be calibrated to manufacturer's specifications; the temperature monitor must be calibrated to within ± 2.0 percent at absolute temperature; the pressure monitor must be calibrated to within ± 5.0 mmHg.

i. If VOC monitoring is chosen: Calibration of the analyzer shall follow the procedures and requirements of Section 10.0 of 40 CFR Part 60, Appendix B, Performance Specification 9, as amended through October 17, 2000, (65 FR 61744), except that the multi-point calibration procedure in Section 10.1 of Performance Specification 9 shall be performed at least once every calendar quarter instead of once every month, and the mid-level calibration check procedure in Section 10.2 of Performance Specification 9 shall be performed at least once every calendar week instead of once every 24 hours. The on-line analyzer system must be capable of measuring constituents sufficient to determine the net heating value of the gas combusted in the flare to within 5.0%, or be calibrated with certified standards of the top two constituents affecting net heating value, whichever is more stringent and the ranges of calibration standards may be based on the typical concentrations observed rather than the full potential range of concentrations. The calibration gases used for calibration procedures shall be in accordance with Section 7.1 of Performance Specification 9. Net heating value of the gas combusted in the flare shall be calculated according to the equation given in 40 CFR § 60.18(f)(3) as amended through October 17, 2000, (65 FR 61744).

ii. If heating value is chosen: The calorimeter shall be calibrated, installed, operated, and maintained, in accordance with manufacturer recommendations, to continuously measure and record the net heating value of the gas sent to the flare, in British thermal units/standard cubic foot of the gas.

E. Single Carbon Adsorption or Scrubber System

A single liquid scrubbing or single carbon canister adsorption system may be used as a sole control device if the requirements below are satisfied.

(1) The exhaust to atmosphere shall be continuously monitored with a CEM. The VOC concentration shall be recorded at least once every 15 minutes when waste gas is directed to the CAS or scrubber.

(2) The method of VOC sampling and analysis shall be by detector meeting the requirements of SC No. 52 except 52.C.

(3) An alarm shall be installed such that an operator is alerted when outlet VOC concentration exceeds 100 ppmv above background. The MSS activity shall be stopped as soon as possible when the VOC concentration exceeds 100 ppmv above

background for more than one minute. The date and time of all alarms and the actions taken shall be recorded.

F. A closed loop refrigerated vapor recovery system

(1) The vapor recovery system shall be installed on the facility to be degassed using good engineering practice to ensure air contaminants are flushed from the facility through the refrigerated vapor condensers and back to the facility being degassed. The vapor recovery system and facility being degassed shall be enclosed except as necessary to insure structural integrity (such as roof vents on a floating roof tank).

(2) VOC concentration in vapor being circulated by the system shall be sampled and recorded at least once every 4 hours at the inlet of the condenser unit with an instrument meeting the requirements of SC No. 52.

(3) The quantity of liquid recovered from the tank vapors and the tank pressure shall be monitored and recorded each hour. The liquid recovered must increase with each reading and the tank pressure shall not exceed one inch water pressure while the system is operating.

G. Other control devices approved by the TCEQ through a permit amendment application or a pollution control permit application.

62. The following requirements apply to capture systems for the plant flare system.

A. Each capture system for the plant flare system shall comply with one of the following:

(1) 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; or

(2) verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21 once a year. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

B. The control device shall not have a bypass.

C. If any of the inspections under A of this condition is not satisfactory, the permit holder shall promptly take necessary corrective action. Records shall be maintained documenting the performance and results of the inspections required in this condition.

63. If spray guns are used to apply paint, they shall be airless, high volume low pressure (HVLP), or have the same or higher transfer efficiency as airless or HVLP spray guns.

64. Emissions from all painting activities, except for minor painting identified in Attachment 2 to this permit, at this site must satisfy the criteria below. New compounds may also be added through the use of the procedure below.

A. Short-term (pounds per hour [lb/hr]) and annual (TPY) emissions shall be determined for each chemical in the paint as documented in the permit application. The calculated emission rate shall not exceed the maximum allowable emissions rate at any emission point.

B. The Effect Screening Level (ESL) for the material shall be obtained from the current TCEQ ESL list or by written request to the TCEQ Toxicology Division.

C. The total painting emissions of any compound must satisfy one of the following conditions:

(1) The total emission rate is less than 0.1 lb/hr and the ESL greater than or equal to 2 µg/m^3; or

(2) The emission rate of the compound in pounds per hour is less than the ESL for the compound divided by 171.5 (ER<ESL/171.5).

D. The permit holder shall maintain records of the information below and the demonstrations in steps A though C above. The following documentation is required for each compound:

(1) Chemical name(s), composition, and chemical abstract registry number if available.

(2) Material Safety Data Sheet.

(3) Maximum concentration of the chemical in weight percent

(4) Paint usage and the associated emissions shall be recorded each month and the rolling 12 month total emissions updated.

65. No visible emissions shall leave the property due to painting or abrasive blasting.

66. Black Beauty and Garnet Sand 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 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.

D. Blasting media usage and the associated emissions shall be recorded each month and the rolling 12 month total emissions updated.

67. Planned maintenance activities must be conducted in a manner consistent with good practice for minimizing emissions, including the use of air pollution control equipment, practices and processes. All reasonable and practical efforts to comply with SC Nos. 49 through 66, 68, and 69 must be used when conducting the planned maintenance activity, until the commission determines that the efforts are unreasonable or impractical, or that the activity is an unplanned maintenance activity.

68. Slab cleaning activities are limited to water washing small pieces of process equipment, empty vacuum trucks, and empty portable frac containers. Records shall be maintained of the number of items cleaned each day and the emissions determined each month based on the number of items cleaned as estimated in the permit amendment application, PI-1 dated December 21, 2006. The permit holder may assume that all vacuum trucks and frac tanks used on the site as recorded in SC Nos. 56 and 57 are cleaned in lieu of maintaining cleaning records for those items.

69. The following requirements ensure satisfactory impacts off-site during MSS.

A. A maximum of 3 frac or temporary storage tanks or vessels may be filled with naphtha during any one hour period.

B. Emissions from refilling tanks with a landed roofs with a liquid with a vapor pressure greater than 0.50 psia shall be routed to a control device meeting the requirements of SC No. 61 unless the tank has been cleaned and degassed.

C. While filling a tank with a landed roof with a liquid with vapor pressure greater than 0.50 psia without emission control, no other tanks with landed roofs may be degassed or filled with that type of liquid.

D. If a cleaned and degassed tank with a landed roof has been refilled with a liquid with vapor pressure greater than 0.50 psia without emission control in the past 12 months, emissions from refilling the tank with a landed roof shall be routed to a control device meeting the requirements of SC No. 61 if the liquid has a vapor pressure greater than 0.50 psia.

70. Records shall be maintained in accordance with SC No. 50 for planned MSS on the Air Liquide Large Industries SMR (Permit 34245, RN103120929). Total waste gas directed to the Valero flares during these operations shall not exceed the total identified in the permit amendment application, PI-1 dated September 23, 2014. **(03/16)**

71. The following steps shall take place before the catalyst is removed from the HDS unit for transfer to the catalyst pad. The reactor shall be cooled prior to opening and the catalyst shall be flushed with gas oil followed by hydrogen recycle gas circulation. The catalyst shall then be neutralized with a demineralized water and soda ash solution.

72. Each of the following EPNs may not exceed the hours of MSS operation per calendar year shown in the table. **(03/16)**

Emission Point Number	Hours of MSS operation per calendar year
30-B-04MSS	36
16-P-11	52
16-P-12	52
16-P-13	52
16-P-14	52

Permit References

73. The permit holder shall maintain a copy of the effective permit at the site together with complete copies of all confidential documents that are referenced in the above permit conditions as attachments. The permit and attachments shall be made available to TCEQ personnel at the site upon request.

Emission Cap Compliance Recordkeeping

74. Recordkeeping programs for those facilities authorized by the permit shall be established and maintained such that the ability to demonstrate compliance with all authorized emission caps and individual emission rate limits (short-term and annual) is ensured. Records of all compliance testing, CEMS/PEMS results, and process parameters necessary to demonstrate compliance with the emission rate caps shall be maintained on-site for a period of five years.

Emissions calculations for verifying compliance with the emission caps shall be performed at least once every quarter to demonstrate compliance with the annual rolling average requirement. The holder of this permit shall maintain all records necessary to demonstrate compliance with the short-term (lb/hr) and annual TPY emissions cap and provide such demonstration of compliance to the TCEQ Corpus Christi Regional Office upon request.

The emissions shall be determined using the following techniques: **(02/18)**

Fugitive	Component counts using the emission factors and method specified in the permit application.
Cooling Towers	Measured strippable VOC concentration as specified in SC No. 30 and the cooling tower circulation rate.
Tanks	As specified in SC No. 28.
Heaters/Boilers	If a CEMS is installed, as specified in SC No. 40. If stack tested per SC No. 39, using the most recent stack test result and recorded firing rate for the period. If no sampling is required, using the emission factor in the permit application and the recorded firing rate for the period.
Loading	Fugitive emissions from loading operations shall be calculated using: (a) AP 42 loading equation listed in Chapter 5.2 and (b) the TCEQ publication titled "Technical Guidance for Chemical Sources Loading Operations." Emissions from control devices shall be determined using the emission factor (in mg/l) determined through testing and the volume loaded. The manufacturer's guaranteed emission factor may be used if the most recent stack testing has verified that factor.
SRU/HOC	If a CEMS is installed, as specified in SC No. 40.
Scrubber	If stack tested per SC No. 38, using the most recent stack test result and recorded operating rate for the period. If no sampling is required, using the emission factor in the flexible permit application and the average value of the appropriate operating parameter for the period.
Diesel Engines	Emissions calculated based on hours of operation and emission factors listed on Table D-1 in the confidential section of the permit amendment application dated November 16, 2004.

These and all other records required by any previous condition of this permit shall be made available to the TCEQ Executive Director or his representative upon request.

Federal Applicability

75. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources promulgated for the following: **(TBD**)

    A. Petroleum Refineries in 40 CFR Part 60, Subparts A , J, and Ja as follows: **(04/16)**

        (1) All heaters and boilers – Subpart J, except as noted below;

(2) Desalter Heater (EPN 114), Heater 31-H-01 (EPN: 117), Boiler 30-B-04 (EPN: 30-04), and Boiler 30-B-05 (EPN 30-B-05) – Subpart Ja

(3) HOC – Subpart J

(4) HOC – Subpart Ja (upon startup of the HOC Reconfiguration Project (Project 333877)

(5) SRU's – Subpart J

(6) BUP Flare, Main Flare, and Ground Flare – Subpart Ja

B. Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, in 40 CFR Part 60, Subparts A and K.

C. Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984, in 40 CFR Part 60, Subparts A and Ka.

D. Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, in 40 CFR Part 60, Subparts A and Kb.

E. Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006, in 40 CFR Part 60, Subparts A and VV.

F. Bulk Gasoline Terminals in 40 CFR Part 60, Subparts A and XX.

G. Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after January 4, 1983, and on or Before November 7, 2006, in 40 CFR Part 60, Subparts A and GGG.

H. The VOC Emissions from SOCMI Distillation Operations in 40 CFR Part 60, Subparts A and NNN.

I. The VOC Emissions from Petroleum Refinery Wastewater Systems in 40 CFR Part 60, Subparts A and QQQ.

J. The VOC Emissions from SOCMI Reactor Processes in 40 CFR Part 60, Subparts A and RRR.

76. These facilities shall comply with all applicable requirements of EPA regulations on National Emission Standards for Hazardous Air Pollutants (NESHAPS) promulgated for the following:

A. Asbestos in 40 CFR Part 63, Subparts A and M.

B. Benzene Waste Operations in 40 CFR Part 63, Subparts A and FF.

77. These facilities shall comply with all applicable requirements of EPA regulations on National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Source Categories promulgated for the following:

A. Marine Tank Vessel Loading Operations in 40 CFR Part 63, Subparts A and Y.

B. Hazardous Air Pollutants from Petroleum Refineries in 40 CFR Part 63, Subparts A and CC.

C. Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units in 40 CFR Part 63, Subparts A and UUU.

D. Industrial, Commercial, and Institutional Boilers and Process Heaters in 40 CFR Part 63, Subparts A and DDDDD. **(02/18)**

E. Hazardous Air Pollutants: Site Remediation in 40 CFR Part 63, Subparts A and GGGGG.

Referenced Permit by Rule Authorizations

78. The following sources and/or activities are authorized under a Permit by Rule (PBR) by Title 30 Texas Administrative Code Chapter 106 (30 TAC Chapter 106). These lists are not intended to be all inclusive and can be altered without modifications to this permit. **(04/22)**

Authorization	Source or Activity
PBR No. 155846	Control of liquid petroleum gas (LPG) unloading with a portable vapor combustion unit.

Sour Water Storage Tanks

79. The sour water storage tanks shall be subject to the following conditions: **(TBD)**

A. The sour water storage tank system shall be maintained by either of the following methods:

(1) A minimum sour water retention time of 2.0 days in conjunction with a hydrocarbon detection and flow diversion system designed to prevent hydrocarbon carryover to the SRUs by routing sour waters with unacceptable levels of hydrocarbons to the tanks listed in A of this condition. Retention time shall be calculated and recorded daily using the daily average combined tank volume of all sour water tanks and the daily average combined feed rates to the sour water strippers.

(2) A minimum sour water retention time of 3.0 days

B. If acid gas flaring takes place that might be traced to hydrocarbon carryover from the sour water system, the operator shall engage a third-party consultant to complete a Root Cause Failure Analysis (RCFA) within 90 days after the acid gas flaring event in question. The Beaumont Regional Office shall be supplied with a copy of the RFCA within 10 days of it being completed. If the RCFA determines that the acid gas flaring event can be traced to sour water system hydrocarbon carryover that is partially or totally caused by inadequate retention or hold up times, the holder of this permit shall implement one of the following options within 60 days after completion of the RFCA:

(1) The holder of this permit shall submit design information and a proposed implementation schedule to the TCEQ Office of Permitting and Registration for three days of sour water retention and hold up time based on maximum expected feed rates to the sour water strippers, or

(2) Design information and implementation schedule of a proposed alternative other than increased sour water retention time.

C. For periods of planned maintenance activity for the sour water tank, the sour water stripper surge system shall have a reduced minimum on-line retention time of one and a half days based on the sour water flow rate into the tanks. Records of these periods and the corresponding maintenance activity must be maintained and made available upon request.

Greenhouse Gas Emissions

80. Permit holders must keep records sufficient to demonstrate compliance with 30 Texas Administrative Code § 116.164. If construction, a physical change or a change in method of operation results in Prevention of Significant Deterioration (PSD) review for criteria pollutants, records shall be sufficient to demonstrate the amount of emissions of GHGs from the source as a result of construction, a physical change or a change in method of operation does not require authorization under 30 TAC §116.164(a). If there is construction, a physical change or change in the method of operation that will result in a net emission increase of 75,000 tpy or more CO_{2e} and PSD review is triggered for criteria pollutants, greenhouse gas emissions are subject to PSD review. **(TBD)**

81. Monitoring, quality assurance/quality control requirements, emission calculation methodologies, record keeping, and reporting requirements related to Greenhouse Gas (GHG) emissions shall adhere to the applicable requirements in 40 CFR Part 98 and in this permit. **(TBD)**

82. Beginning after the start-up of the new and modified sources associated with the HOC Reconfiguration Project (TCEQ Project 333877), modification and construction, the permittee shall calculate the CO_{2e} emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. This condition applies to the following EPNs: 121 (HOC contribution only), FUG-CAP (new components added for Project 333877), and 30-B0-05. **(TBD)**

83. Records of emissions of GHG, and how they were determined, in compliance with Special Condition Nos. 80, 81, and 82 must be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and must be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction. **(TBD)**

84. Operational and Monitoring requirements for Boiler 30-B-05. **(TBD)**

   A. Boiler 30-B-05 shall be operated with a net thermal efficiency of no less than 78 percent on a 12-month rolling average, excluding periods of maintenance, startup and shutdown. This shall be ensured by using the following good combustion practices: operating the boiler at an optimum air-fuel ratio, limiting the boiler's operating temperature to the extent practicable, and reducing heat loss through the use of insulating materials where feasible.

   B. Thermal efficiency shall be calculated and recorded at least monthly using equation G-1 from American Petroleum Institute (API) method 560 (4th ed. or later), Annex G using monitoring data collected as required under this permit, other quality-assured data, and engineering judgment.

      If the maximum range between twelve or more consecutive monthly efficiency calculations does not exceed 5 percentage points, and each calculation demonstrates compliance with the minimum efficiency requirements of this paragraph, the permit holder may elect to reduce the frequency of performing the calculation to quarterly (skipping up to two monthly calculations); provided, however, that:

(1) In case a quarterly efficiency calculation yields an efficiency value outside of the maximum range specified in this previous paragraph, monthly efficiency calculations shall be resumed.

(2) In case a quarterly efficiency calculation shows non-compliance with the minimum efficiency requirement of this paragraph, the permit holder shall assume that a condition of non-compliance occurred during each month of the previous quarter where a calculation was skipped.

Date: TBD

Attachment 1

Permit Numbers 38754, PSDTX324M15, and GHGPSDTX211

Permit Emission Points by Type

Category	EPN	Description
Fired Units	1	Crude Heater
	16-P-04	Diesel Pump
	16-P-07	Diesel Pump
	16-P-11	Diesel Pump
	16-P-12	Diesel Pump
	16-P-13	Diesel Pump
	16-P-14	Diesel Pump
	49-H-90	C7 Splitter Reboiler
	74	Vacuum Unit Heater
	83-P-136A	Diesel Pump
	83-P-136B	Diesel Pump
	114	Desalter Heater
	115	HDS Charge Heaters
	116	HDS Heavy Oil Preheater
	117	Alky Fract Reboiler
	118	Hydrogen Reformer Heater
	119	Sulften Heater
	120	Butamer Heater
	121	HOC (incinerator and scrubber stack)
	121a	SRU Bypass Stack
	124	API Separator Combustor
	131	Crude Preflash Heater
	132	Crude Stabilizer Heater
	150	HCU Heater
	151	NHT Heater
	152	CRU Heaters
	153	Boiler 30-B-02
	162	Oleflex Heaters

	172	RSU Heater
	30-B-04	Boiler 30-B-04
	30-B-04MSS	Boiler 30-B-04MSS
	195	GD Charge Heater
	900	Crude Charge Heater (Permit No. 106965)
	TRUCKCOMB	Truck Loading Combustor
	30-B-05	Boiler 30-B-05
Flares	126	Main Flare
	127	MTBE Flare
	135	Acid Gas Flare (Pilots Only)
	158	Ground Flare
Tanks	69	Tank No. 9
	83-TK-26	Tank No. 26
	83-TK-155	Tank No. 155
	83-TK-159	Tank No. 159
	83-TK-160	Tank No. 160
	83-TK-162	Tank No. 162
	187	Tank No. 25 (Sour Water Tank)
	902	Tank No. 165 (Permit No. 106965)
Fugitive	1F	Crude Unit
	2F	Vacuum Unit
	4F	LEU
	07F	BUP Flare
	08F	08 FLR/Day Tanks
	11F	Desalter Unit
	12F	HDS Unit
	13F	SMR
	18F	HRLEU Unit
	20F	LRU
	21/22F	HOC Unit
	30F	Boilerhouse

	31F	HF Alkylation Unit
	36F	Butamer Unit
	37F	MTBE
	38F	Oleflex
	41F	SRU Unit
	42F	SWS
	46-24F	SULF/SEU
	47F	HCU
	47PSAF	PSA
	48F	NHT
	49F	CRU
	52F	Gasoline Desulfurization
	54F	SHU
	83F	WWT
	175	49-RSU/XFU
	201	Railcar Unloading
	DOCKS	Docks
	LPGSTGF	LPG Storage
	MVRUF	MVRU
	TERM-F	Terminals
	TRKRACKFUG	Truck Rack
	903	Crude Unit Fugitives (Permit No. 106965)
	904	Crude Unit BWS Fugitives (Permit No. 106965)
	908	Crude Storage Fugitives (Permit No. 109543)
	##F	Selective Hydrogenation Unit
	##F	LPG Gas Plant
	##F	Boiler 30-B-05
Loading	31	Barge Loading (Heavy Oil)
	SHIP FUG	Ship Dock Fugitives
	TRUCKFUG	Truck Loading
	VRU	Marine loading VRU

	907	Crude Loading Fugitives (Permit No. 109543)
	909	Crude Loading Vapor Combustor (Permit No. 109543)
Other	1CT	CU/VRU Cooling Tower
	01-01	Crude/Vac Pump Alley
	01-02	North of Vac Unit
	01-03	North of Vac Unit
	50-01	East of Tank 62
	52-01	NW of GDU MCC
	70-01	East of Tank 55
	70-02	NW of Tank 106
	70-03	West of Tank 94
	72-01	East of Tank 111
	73-01	North of Tank 152
	73-01	Between TK 8 & TK 164
	83-01	WWT-Hydroblast Pad
	01-04	NW of Vac Unit
	03-01	North of tanks 156/161
	11-01	Desalter Pump Alley
	21BH	Magnacat Unit
	41-01	North of 43-TK-08
	41-02	West of 41-V-05
	49-01	NW of XFU
	49-02	North of NHT
	49-03	NHT Pump Alley
	83-02	WWT-Desalter Lift
	83-03	WWT-East of KOH Trtr
	83-04	WWT- NE of Tank 159
	83-05	WWT-North Lift
	83-06	WWT-North of V-68
	83-07	WWT-South of V-55

	83-09	WWT-BSRP
	83-10	WWT-83-V-99
	83-12	WWT-83-V-28
	83-TK-23	Equalization Tank
	83-TK-27	Bio Oxidation Tank
	83-V-58	Tank No. 58
	83-V-59	Tank No. 59
	83-V-97	Tank No. 97
	98-02	WP MSAT Rail Rack
	122	HOC Cooling Tower
	123	ALKY Cooling Tower
	124a	API Sep Back Up
	155	CCU CCR
	901	Crude Unit Cooling Tower (Permit No. 106965)
	168	Oleflex CCR
	AE-49601A/B	Analyzer Vent AE-49601A/B
	167-CT	BUP Cooling Tower
	AE-49900A/B	Analyzer Vent AE-49900A/B
	AE-49901A/B	Analyzer Vent AE-49901A/B
	V-201	WP MSAT Rail Rack
	WWTP-AERB	Aeration Basin
	WWTP-CLRF	Clarifier
	WWTP-OWS	WW Collection System
	WWTP-SLB	Salin Basin
	HOC-PP-CT	Cooling Tower -Propylene Project
	XX-01	HOC PP Gas Plant CAS

Date: TBD

Attachment 2

Permit Numbers 38754, PSDTX324M15, and GHGPSDTX211

Inherently Low Emitting Activities

	Emissions				
Activity	**VOC**	**NO_x**	**CO**	**PM**	**H_2S/SO_2**
Catalyst activation/deactivation	x				
Management of sludge from pits, ponds, sumps, and water conveyances	x				
Aerosol Cans	x				
Calibration of analytical equipment and process instrumentation	x	x	x		x
Carbon canister replacement	x				
Catalyst charging/handling				x	
Instrumentation/analyzer maintenance	x				
Meter proving	x				
Replacement of analyzer filters and screens	x				
Maintenance on water treatment systems (cooling, boiler, potable)	x				
Soap and other aqueous based cleaners	x				
Cleaning sight glasses	x				
Aerosol and miscellaneous chemical usage	x				

Date: January 22, 2016

Attachment 3

Permit Numbers 38754, PSDTX324M15, and GHGPSDTX211

Routine Maintenance Activities

Pump repair/replacement

Fugitive component (valve, pipe, flange) repair/replacement

Compressor repair/replacement

Heat exchanger repair/replacement

Vessel repair/replacement

Date: January 22, 2014

Attachment 4

Permit Numbers 38754, PSDTX324M15, and GHGPSDTX211

MSS Activity Summary

Facilities	Description	Emissions Activity	EPN
all process units and tanks	shutdown/depressurize/ drain/startup (includes SRU shutdowns, FCCU startups and Air Liquide MSS activities)	Vent to control	MSS Turnaround (MSS-TA) Routine MSS (MSS-MA)
all process units and tanks	process unit purgegas/drain/startup (except FCCU and SRU)	Vent to atmosphere	MSS-TA Uncontrolled MSS-MA Uncontrolled
Vacuum Trucks	removal and transfer of process and/or waste liquids	Vent to atmosphere	MSS-TA Uncontrolled MSS-MA Uncontrolled
Process units and tanks	Painting	Vent to atmosphere	MSS-TA Uncontrolled MSS-MA Uncontrolled
Process units and tanks	Miscellaneous chemical usage	Vent to atmosphere	MSS-TA Uncontrolled MSS-MA Uncontrolled
FRAC tanks	Temporary storage of process liquids and/or waste liquids	Vent to atmosphere	MSS-TA Uncontrolled MSS-MA Uncontrolled
Cleaning Slab	Washing of portable or mobile MSS or process equipment	vent to atmosphere	MSS-TA Uncontrolled MSS-MA Uncontrolled
Process units and tanks	Abrasive blasting	Vent to atmosphere	MSS-TA Uncontrolled
HDS	Remove spent catalyst, store on pad prior to transfer	Vent to atmosphere	MSS-TA Uncontrolled
Boiler 30-B-04	Startup and shutdown	Vent to atmosphere	30-B-04 MSS
Firewater Pump Engines	Test runs	Vent to atmosphere	16-P-11, 16-P-12, 16-P-13, and 16-P-14

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 38754 and PSDTX324M15

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)
MSS Caps	MSS Caps	CO	2,085.19	128.91
		H_2S	10.59	0.22
		NH_3	4.41	0.17
		NO_x	356.84	27.19
		PM	79.52	3.76
		PM_{10}	79.52	2.92
		$PM_{2.5}$	79.52	2.92
		SO_2	996.29	338.89
		VOC	578.44	70.04
		Exempt Solvents	1.76	0.60
1	Heater - Crude Heater (01-H-01)	CO	8.10	20.13
		NH_3	0.05	0.17
		NO_x	9.72	19.24
		PM	1.21	4.00
		PM_{10}	1.21	4.00
		$PM_{2.5}$	1.21	4.00
		SO_2	2.50	5.71
		VOC	0.87	2.90
131	Heater - Crude Preflash (01-H-02)	CO	0.62	2.71
		NH_3	<0.01	0.02
		NO_x	1.77	6.29
		PM	0.13	0.49
		PM_{10}	0.13	0.49
		$PM_{2.5}$	0.13	0.49

Emission Sources - Maximum Allowable Emission Rates

		SO_2	0.27	0.64
		VOC	0.10	0.35
132	Heater - Crude Stabilizer (01-H-03)	CO	0.17	0.72
		NH_3	<0.01	<0.01
		NO_x	0.48	2.06
		PM	0.04	0.15
		PM_{10}	0.04	0.15
		$PM_{2.5}$	0.04	0.15
		SO_2	0.07	0.22
		VOC	0.03	0.11
74	Vacuum Heater	CO	4.99	16.77
		NH_3	0.03	0.14
		NO_x	5.98	26.21
		PM	0.74	3.26
		PM_{10}	0.74	3.26
		$PM_{2.5}$	0.74	3.26
		SO_2	1.37	4.13
		VOC	0.54	2.36
114	Heater - Desalter Heater (11-H-01)	CO	3.54	15.52
		CO	3.54	15.52
		NH_3	0.03	0.14
		NO_x	3.96	17.34
		PM	0.74	3.23
		PM_{10}	0.74	3.23
		$PM_{2.5}$	0.74	3.23
		SO_2	1.52	4.60
		VOC	0.53	2.34
		H_2S	0.02	0.05
115	HDS Heaters	CO	8.08	32.91

Emission Sources - Maximum Allowable Emission Rates

		NH_3	0.05	0.22
		NO_x	9.70	42.07
		PM	1.20	5.22
		PM_{10}	1.20	5.22
		$PM_{2.5}$	1.20	5.22
		SO_2	2.49	7.45
		VOC	0.87	3.78
115	HDS Heaters	CO	8.08	32.91
		NH_3	0.05	0.22
		NO_x	9.70	42.07
		PM	1.20	5.22
		PM_{10}	1.20	5.22
		$PM_{2.5}$	1.20	5.22
		SO_2	2.49	7.45
		VOC	0.87	3.78
116	Heater - HDS Pre-Heater (12-H-02)	CO	0.31	1.10
		NH_3	<0.01	0.02
		NO_x	2.36	8.28
		PM	0.15	0.51
		PM_{10}	0.15	0.51
		$PM_{2.5}$	0.15	0.51
		SO_2	0.30	0.73
		VOC	0.11	0.37
118	Hydrogen Reformer Heater	CO	58.51	220.73
		NH_3	0.37	1.52
		NO_x	70.21	284.40
		PM	8.72	35.80
		PM_{10}	8.72	35.80
		$PM_{2.5}$	8.72	35.80

Emission Sources - Maximum Allowable Emission Rates

		SO_2	44.53	122.64
		VOC	9.95	25.91
153	Heater - HR Boiler (30-B-02)	CO	8.46	28.94
		NH_3	0.09	0.33
		NO_x	22.56	82.34
		PM	2.10	5.51
		PM_{10}	2.10	5.51
		$PM_{2.5}$	2.10	5.51
		SO_2	4.34	10.66
		VOC	1.52	3.99
30-B-04	Boiler 30-B-04	CO	19.84	48.14
		NH_3	2.41	5.86
		NO_x	8.25	20.02
		PM	4.10	9.95
		PM_{10}	4.10	9.95
		$PM_{2.5}$	4.10	9.95
		SO_2	8.65	14.47
		VOC	2.97	7.20
30-B-04MSS	Boiler 30-B-04	CO	198.55	3.57
		NO_x	55.00	0.99
117	Heater - Alky Frac. Reb. (31-H-01)	CO	2.51	8.83
		NH_3	0.05	0.17
		NO_x	5.64	19.86
		PM	1.17	4.11
		PM_{10}	1.17	4.11
		$PM_{2.5}$	1.17	4.11
		SO_2	2.41	5.86
		VOC	0.85	2.97
120		CO	0.27	0.98

Emission Sources - Maximum Allowable Emission Rates

	Heater - Butamer Heater (36-H-01)	NH_3	<0.01	0.02
		NO_x	2.00	4.30
		PM	0.12	0.26
		PM_{10}	0.12	0.26
		$PM_{2.5}$	0.12	0.26
		SO_2	0.26	0.41
		VOC	0.09	0.19
162	Oleflex Heater	CO	19.45	69.49
		NH_3	0.12	0.49
		NO_x	23.34	65.75
		PM	2.90	11.62
		PM_{10}	2.90	11.62
		$PM_{2.5}$	2.90	11.62
		SO_2	5.99	16.57
		VOC	2.10	8.41
119	Heater - Sulften Heater (46-H-01)	CO	0.35	1.49
		NH_3	0.01	0.03
		NO_x	2.62	5.21
		PM	0.16	0.32
		PM_{10}	0.16	0.32
		$PM_{2.5}$	0.16	0.32
		SO_2	0.34	0.63
		VOC	0.12	0.24
150	HCU Heater	CO	6.10	24.38
		NH_3	0.06	0.26
		NO_x	12.19	48.76
		PM	1.51	6.06
		PM_{10}	1.51	6.06
		$PM_{2.5}$	1.51	6.06

Emission Sources - Maximum Allowable Emission Rates

		SO_2	3.13	8.63
		VOC	1.10	4.38
151	Heater - NHU Heater (48-H-01)	CO	3.05	6.68
		NH_3	0.01	0.05
		NO_x	3.90	17.08
		PM	0.29	1.27
		PM_{10}	0.29	1.27
		$PM_{2.5}$	0.29	1.27
		SO_2	0.60	1.81
		VOC	0.21	0.92
152	CRU Heater	CO	16.85	57.02
		NH_3	0.18	0.60
		NO_x	39.31	133.06
		PM	4.18	14.16
		PM_{10}	4.18	14.16
		$PM_{2.5}$	4.18	14.16
		SO_2	9.80	22.69
		VOC	3.03	10.25
172	Heater - RSU Heater (49-H-71)	CO	3.30	12.72
		NH_3	0.02	0.08
		NO_x	3.96	15.26
		PM	0.49	1.90
		PM_{10}	0.49	1.90
		$PM_{2.5}$	0.49	1.90
		SO_2	1.02	2.70
		VOC	0.36	1.37
49-H-90	Heater - C7 Splitter Reb. (49-H-90)	CO	5.32	16.82
		NH_3	0.03	0.13
		NO_x	4.25	15.46

Emission Sources - Maximum Allowable Emission Rates

		PM	0.79	3.01
		PM_{10}	0.79	3.01
		$PM_{2.5}$	0.79	3.01
		SO_2	1.64	4.29
		VOC	0.57	2.18
195	Heater - GDU Charge Heater (52-H-01)	CO	13.65	34.29
		NH_3	0.05	0.20
		NO_x	5.80	14.69
		PM	1.23	4.61
		PM_{10}	1.23	4.61
		$PM_{2.5}$	1.23	4.61
		SO_2	2.55	6.57
		VOC	0.89	3.34
1F	Crude Unit	VOC	See Subcap	See Subcap
2F	Vacuum Unit	H_2S	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
4F	LEU Unit	VOC	See Subcap	See Subcap
11F	Desalter Unit	VOC	See Subcap	See Subcap
12F	HDS Unit	H_2S	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
13F	H_2 Reformer	VOC	See Subcap	See Subcap
18F	LEU -2	VOC	See Subcap	See Subcap
20F	LRU	VOC	See Subcap	See Subcap
21/22F	HOC	H_2S	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
30F	Boiler House	VOC	See Subcap	See Subcap
07F	#07 BUP Flare	VOC	See Subcap	See Subcap
31F	Alky Unit	H_2S	See Subcap	See Subcap
		HF	0.52	2.30

Emission Sources - Maximum Allowable Emission Rates

		VOC	See Subcap	See Subcap
36F	Butamer Unit	VOC	See Subcap	See Subcap
37F	Iso-Octene	VOC	See Subcap	See Subcap
38F	Oleflex Unit	VOC	See Subcap	See Subcap
46-24F	SULF-10 Fugitives (5)	H_2S	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
41F	SRU Unit Fugitives (5)	H_2S	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
47F	HCU Unit	H_2S	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
47PSA	PSA Unit	VOC	See Subcap	See Subcap
48F	NHT Unit	H_2S	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
49F	CRU Unit	VOC	See Subcap	See Subcap
175	XFU/RFU/C7Split Unit	VOC	See Subcap	See Subcap
52F	GDU Unit	VOC	See Subcap	See Subcap
DOCKS	DK-Docks	VOC	See Subcap	See Subcap
08F	#08FLR/Day Tanks	VOC	See Subcap	See Subcap
LPG STGF	LPG STORAGE	VOC	See Subcap	See Subcap
MVRUF	MVRU	VOC	See Subcap	See Subcap
TERM-F	#TM-Terminal	VOC	See Subcap	See Subcap
TRKRACKFUG	TRUCK RACK (5)	VOC	See Subcap	See Subcap
83F	Wastewater Treatment Plant	VOC	See Subcap	See Subcap
54F	Selective Hydrogenation Unit	VOC	See Subcap	See Subcap
42F	Sour Water Stripper	H_2S	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
##F	Selective Hydrogenation Unit (5)	VOC	See Subcap	See Subcap
##F	LPG Gas Plant (5)	VOC	See Subcap	See Subcap
##F	Boiler 30-B-05 (5)	VOC	See Subcap	See Subcap

Emission Sources - Maximum Allowable Emission Rates

168	Oleflex CCR	Cl_2	<0.01	0.04
		H_2SO_4	<0.01	0.01
		HCl	0.06	0.28
		SO_2	0.04	0.19
69	Tank - 9	VOC	3.10	0.49
122	Cooling Tower - HOC	PM	3.54	13.17
		PM_{10}	3.36	12.52
		$PM_{2.5}$	0.53	1.96
		VOC	5.67	21.09
123	Cooling Tower - Alky	PM	0.71	2.00
		PM_{10}	0.70	1.98
		$PM_{2.5}$	0.19	0.55
		VOC	1.26	3.55
167-CT	Cooling Tower - BUP	PM	4.52	19.26
		PM_{10}	4.30	18.33
		$PM_{2.5}$	0.67	2.88
		VOC	1.47	6.27
1CT	Cooling Tower - Crude	PM	0.34	1.13
		PM_{10}	0.34	1.11
		$PM_{2.5}$	0.06	0.21
		VOC	0.17	0.55
16-P-04	Engine - 16-P-04	CO	2.20	0.06
		NO_x	8.00	0.21
		PM	0.73	0.02
		PM_{10}	0.73	0.02
		$PM_{2.5}$	0.73	0.02
		SO_2	0.68	0.02
		VOC	0.83	0.02
16-P-07	Engine - 16-P-07	CO	2.67	0.04

Emission Sources - Maximum Allowable Emission Rates

		NO_x	9.69	0.15
		PM	0.88	0.01
		PM_{10}	0.88	0.01
		$PM_{2.5}$	0.88	0.01
		SO_2	0.82	0.01
		VOC	1.01	0.02
16-P-11	Engine - 16-P-11	CO	0.80	0.02
		NO_x	3.32	0.09
		PM	0.11	<0.01
		PM_{10}	0.11	<0.01
		$PM_{2.5}$	0.11	<0.01
		SO_2	0.10	<0.01
		VOC	0.12	<0.01
16-P-12	Engine - 16-P-12	CO	0.80	0.02
		NO_x	3.32	0.09
		PM	0.11	<0.01
		PM_{10}	0.11	<0.01
		$PM_{2.5}$	0.11	<0.01
		SO_2	0.10	<0.01
		VOC	0.12	<0.01
16-P-13	Engine - 16-P-13	CO	0.80	0.02
		NO_x	3.32	0.09
		PM	0.11	<0.01
		PM_{10}	0.11	<0.01
		$PM_{2.5}$	0.11	<0.01
		SO_2	0.10	<0.01
		VOC	0.12	<0.01
16-P-14	Engine - 16-P-14	CO	0.80	0.02
		NO_x	3.32	0.09

Emission Sources - Maximum Allowable Emission Rates

		PM	0.11	<0.01
		PM_{10}	0.11	<0.01
		$PM_{2.5}$	0.11	<0.01
		SO_2	0.10	<0.01
		VOC	0.12	<0.01
126	Main Flare	CO	See Subcap	See Subcap
		H_2S	See Subcap	See Subcap
		NO_x	See Subcap	See Subcap
		SO_2	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
158	Ground Flare	CO	See Subcap	See Subcap
		H_2S	See Subcap	See Subcap
		NO_x	See Subcap	See Subcap
		SO_2	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
127	BUP Flare	CO	See Subcap	See Subcap
		H_2S	See Subcap	See Subcap
		NO_x	See Subcap	See Subcap
		SO_2	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
135	Acid Gas Flare (pilot only)	CO	See Subcap	See Subcap
		H_2S	See Subcap	See Subcap
		NO_x	See Subcap	See Subcap
		SO_2	See Subcap	See Subcap
		VOC	See Subcap	See Subcap
Various	Flares Subcap	CO	113.27	121.03
		H_2S	0.04	0.11
		NO_x	23.04	20.77
		SO_2	3.55	10.43

Emission Sources - Maximum Allowable Emission Rates

		VOC	291.17	63.51
31	Loading - Heavy Oil	VOC	14.96	4.72
SHIP FUG	Loading - Ships Fugitives (5)	VOC	237.46	91.74
VRU	Loading - MVRU	VOC	61.33	23.13
TRUCKFUG	Loading - Truck Fugitives (5)	VOC	11.86	15.87
TRUCKCOMB	Loading - Truck Combustor	CO	15.28	22.76
		NO_x	7.64	11.38
		SO_2	0.02	0.03
		VOC	8.18	13.61
		PM	0.23	0.34
		PM_{10}	0.23	0.34
		$PM_{2.5}$	0.23	0.34
AE-49601A/B	AE-49601A/B Analyzer Vent	VOC	0.01	0.01
AE-49900A/B	AE-49900A/B Analyzer Vent	VOC	0.01	0.01
AE-49901A/B	AE-49901A/B Analyzer Vent	VOC	0.01	0.01
121 (6)	HOC Belco Scrubber	CO	958.40	1559.15
		HCN	80.47	320.40
		H_2SO_4	49.00	199.30
		NO_x	384.12	473.81
		PM	140.00	569.40
		PM_{10}	140.00	569.40
		$PM_{2.5}$	140.00	569.40
		SO_2	223.08	437.03
		VOC	30.42	123.79
		H_2S	<0.01	<0.01
		NH_3	4.84	17.88
121 (6)	SRU Incinerators Cap	CO	220.75	678.85
		H_2S	5.82	18.73
		NO_x	54.64	239.31

Emission Sources - Maximum Allowable Emission Rates

		PM	24.72	98.38
		PM_{10}	24.72	98.38
		$PM_{2.5}$	24.72	98.38
		SO_2	191.32	837.99
		VOC	0.96	3.46
121 (6)	Temporary SRU Stack	CO	10.04	7.23
		H_2S	0.047	0.03
		NO_x	1.233	0.72
		PM	1.205	0.87
		PM_{10}	1.205	0.87
		$PM_{2.5}$	1.205	0.87
		SO_2	13.816	9.95
FUG-CAP	Fugitives Subcap (5)	VOC	112.45	492.32
		H_2S	0.59	2.58
		NH_3	0.01	0.06
155	CRU CCR	HCl	0.07	0.29
118	SMR Condenser Vent	VOC	3.64	15.94
21 BH	MAGNACAT Unit	PM	0.18	0.60
		PM_{10}	0.18	0.60
		$PM_{2.5}$	0.18	0.60
187	Tank 25	H_2S	0.02	0.04
		NH_3	<0.01	<0.01
		VOC	1.43	5.33
83-P-136A	Engine 83-P-136A-EN	CO	2.48	0.06
		NO_x	7.43	0.19
		PM	0.38	<0.01
		PM_{10}	0.38	<0.01
		$PM_{2.5}$	0.38	<0.01
		SO_2	0.88	0.02

Emission Sources - Maximum Allowable Emission Rates

		VOC	7.43	0.19
83-P-136B	Engine 83-P-136B-EN	CO	2.48	0.06
		NO_x	7.43	0.19
		PM	0.38	<0.01
		PM_{10}	0.38	<0.01
		$PM_{2.5}$	0.38	<0.01
		SO_2	0.88	0.02
		VOC	7.43	0.19
WWTP-OWS	WW collection system	VOC	8.62	37.77
83-TK-26	Tank 26	VOC	0.12	0.45
83-TK-159	Tank 159	VOC	0.15	0.39
83-TK-160	Tank 160	VOC	0.15	0.39
83-V-97	Tank 97	VOC	0.18	0.40
83-V-58	Tank 58	VOC	0.11	0.44
83-V-59	Tank 59	VOC	0.11	0.44
83-TK-162	Tank 162	VOC	0.39	1.77
83-TK-155	Tank 155	VOC	0.39	1.77
124	API/DGF Combustor	CO	1.65	7.22
		NO_x	0.45	1.76
		SO_2	0.03	0.13
		VOC	2.94	12.88
83-TK-23	Equalization Tank	VOC	0.81	3.51
83-TK27	Bio Oxidation Reactor Tank	VOC	0.51	2.22
WWTP-AERB	Aeration Basin	VOC	0.25	1.09
WWTP-CLRF	Clarifier	VOC	<0.01	0.04
WWTP-SLB	Saline Basin	VOC	<0.01	<0.01
01-01	Crude/Vacuum Unit Pump Alley	VOC	<0.01	0.02
01-02	North Side of Vacuum Unit	VOC	<0.01	0.02
01-03	North Side of Vacuum Unit	VOC	<0.01	0.02

Emission Sources - Maximum Allowable Emission Rates

01-04	Northwest Side of Vacuum Unit - Main Sump	VOC	<0.01	0.03
03-01	N of Tanks 156/161	VOC	0.02	0.08
98-02	WP MSAT Rail Rack	VOC	0.02	0.08
11-01	Desalter Pump Alley	VOC	<0.01	0.02
41-01	North of 43-TK-08 (Amine Tank)	VOC	<0.01	0.02
41-02	W of 41-V-05 (Acid Gas K.O. Drum)	VOC	<0.01	0.02
49-01	Northwest of XFU	VOC	<0.01	0.02
49-02	North Side of NHT (Unit 48)	VOC	<0.01	0.02
49-03	NHT (Unit 48) Pump Alley	VOC	<0.01	0.02
50-01	East of Tank 62	VOC	<0.01	0.02
52-01	NW of GDU MCC Room	VOC	<0.01	0.02
70-01	East of Tank 55	VOC	<0.01	0.02
70-02	Northwest of Tank 106	VOC	<0.01	0.02
70-03	West of Tank 94 (S&D Main Sump)	VOC	<0.01	0.03
72-01	East of Tank 111	VOC	<0.01	0.02
73-01	North of Tank 152 (Terminal 2A)	VOC	<0.01	0.02
73-02	Between TK 8 & TK 164 (Terminal 2)	VOC	<0.01	0.02
83-01	WWT (Hydroblast Pad)	VOC	0.02	0.07
83-02	WWT (Desalter Lift Station)	VOC	0.01	0.05
83-03	WWT (East of KOH Treater)	VOC	0.02	0.07
83-04	WWT (Northeast of Tank 159)	VOC	<0.01	0.02
83-05	WWT (North Lift Station)	VOC	<0.01	0.03
83-06	WWT (North of V-68)	VOC	<0.01	0.02
83-07	WWT (South of V-55)	VOC	<0.01	0.02
83-09	WWT (BSRP)	VOC	<0.01	0.02
83-10	WWT 83-V-99 (Diversion Box)	VOC	0.02	0.07
83-12	WWT 83-V-28 (SE of Catalyst Pad)	VOC	0.02	0.07

Emission Sources - Maximum Allowable Emission Rates

V-201	WP MSAT Rail Rack	VOC	0.51	2.23
124a	WP WWT API Combustor Backup	VOC	0.02	0.08
16-V-11	FWP 16-P-11 Diesel Tank	VOC	0.03	<0.01
16-V-12	FWP 16-P-12 Diesel Tank	VOC	0.03	<0.01
16-V-13	FWP 16-P-13 Diesel Tank	VOC	0.03	<0.01
16-V-14	FWP 16-P-14 Diesel Tank	VOC	0.03	<0.01
FWP-FUG	Firewater Pump Engine Fugitives	VOC	0.06	0.26
30-B-05	Boiler 30-B-05	CO	33.48	70.84
		NH_3	2.18	8.68
		NO_x	7.16	30.14
		PM	3.56	14.16
		PM_{10}	3.56	14.16
		$PM_{2.5}$	3.56	14.16
		SO_2	11.56	38.06
		H_2S	<0.01	<0.01
		VOC	2.81	11.30
30-B-05	Boiler 30-B-05 (MSS)	NO_x	71.61	--
HOC-PP-CT	Cooling Tower-Propylene Project	PM	0.78	3.42
		PM_{10}	0.18	0.81
		$PM_{2.5}$	<0.01	0.01
		VOC	1.09	4.78
XX-01	HOC PP Gas Plant CAS	VOC	<0.01	0.02

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) Cl_2 - chlorine
CO - carbon monoxide
HCN - hydrogen cyanide
HF - hydrogen fluoride
H_2S - hydrogen sulfide
H_2SO_4 - sulfuric acid
MSS - Maintenance, Startup and Shutdown
NH_3 - ammonia
NO_x - total oxides of nitrogen
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
SO_2 - sulfur dioxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
(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.

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX211

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for all sources of GHG air contaminants on the applicant's property that are authorized 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 authorized by this permit.

Air Contaminants Data

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**
			TPY (4)
121	HOC Belco Scrubber	CO_2 (5)	2,451,673.00
		CH_4 (5)	72.08
		N_2O (5)	14.42
		CO_2e	2,457,772.00
Various (FUG-CAP)	Fugitives Subcap	CH_4 (5)	3.59
		CO_2e	90.00
30-B-05	Boiler 30-B-05	CO_2 (5)	222,364.00
		CH_4 (5)	4.19
		N_2O (5)	0.42
		CO_2e	22,594.00

(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) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (1/2015):
CO_2 (1), N_2O (298), CH_4(25)
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. These rates include emissions from maintenance, startup, and shutdown.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.

Date: TBD

Preliminary Determination Summary

Valero Refining-Texas, L.P.
Permit Numbers 38754, PSDTX324M15, and GHGPSDTX211

I. Applicant

Valero Refining-Texas LP
PO Box 9370
Corpus Christi, TX 78469-9370

II. Project Location

Valero Corpus Christi Refinery West Plant
5900 Up River Rd
Nueces County
Corpus Christi, Texas 78407

III. Project Description

Valero Refining Texas, LP (Valero) operates the Bill Greehey Refineries located in Corpus Christi, Nueces County. The Bill Greehey Refineries consist of two plants, the West Plant and the East Plant. Operation of the West Plant is currently authorized under Permit Nos. 38754, PSDTX324M14, and various Permit by Rule (PBR) and Standard Permit authorizations. Valero plans to undertake changes to the West Plant Heavy Oil Cracker (HOC), a type of fluidized catalytic cracking (FCC) unit. This project (“HOC Reconfiguration Project”) will necessitate certain operational changes at other existing process units and will entail the construction of a new utility steam boiler, a new cooling tower, a new gas plant, a new sour water stripper, a new liquefied petroleum gas (LPG) Merox Treating Unit, a new Selective Hydrogenation Unit (SHU), a new C3/C4 Splitter Tower, and two new butane/butylene bullet tanks. Maintenance, startup and shutdown (MSS) activities for all process units at the West Plant are currently authorized by permit.

The refinery is an existing named major source under Prevention of Significant Deterioration (PSD) regulations, and is subject to PSD permitting requirements, including Best Available Control Technology (BACT) requirements for emissions of greenhouse gasses (GHG). Since the refinery is located in an area that in attainment for each National Ambient Air Quality Standard (NAAQS), Nonattainment New Source Review (NNSR) does not apply.

IV. Emissions

Total emissions authorized by the draft permit are as follows:

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	1,076.74
NO_x	1,641.33
SO_2	1,596.95
CO	3,183.10
PM	840.90
PM_{10}	836.57
$PM_{2.5}$	807.41

H_2SO_4	199.31
H_2S	21.79
NH_3	37.25
CO_2	2,674,037.00
CH_4	79.86
SF_6	14.84
N2O	2,680,456.00
CO_2 Equivalents (CO_{2e})	2,674,037.00

CO2e - carbon dioxide equivalents based on global warming potentials of CH_4 = 25, N_2O = 298, SF_6=22,800.

V. Federal Applicability

The following chart illustrates the annual project emissions for each pollutant and whether this pollutant triggers PSD or Nonattainment (NA) review.

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	NA Triggered Y/N	PSD Triggered Y/N
VOC	110.70	40	N/A	Y
NO_x	298.80	40	N/A	Y
SO_2	447.70	40	N/A	Y
CO	413.30	100	N/A	Y
PM	241.7	25	N/A	Y
PM_{10}	239.1	15	N/A	Y
$PM_{2.5}$	238.3	10	N/A	Y
H_2SO_4	168.60	7	N/A	Y
H_2S	0.06	10	N/A	N

The proposed project triggers PSD review for non-GHG NSR regulated pollutants. As shown in the table below, because the project increase is more than 75,000 tpy of CO_{2e}, PSD review is triggered for GHG emissions.

Pollutant	Project Emissions (tpy)	Major Source or Major Mod Trigger Level (tpy)	PSD Triggered Y/N
CO2e	1,110,869.00	75,000	Y

The refinery is located in Nueces County, which is classified as attainment for all criteria pollutants. Nonattainment review is not applicable. The refinery is a named source, and as a potential to emit (PTE) in excess of 100 tpy for at least one pollutant. Project increases are calculated using the actual-to-potential applicability test and include modified and affected sources. Baseline actual emissions of new units are assumed to be zero. PSD review applies to the following pollutants for which the PTE exceeds an applicable significance threshold (40 CFR § 52.21(b)(23)(i)): VOC, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, and H_2SO_4. The refinery has a PTE in excess of 100 tpy (mass basis) and 75,000 tpy GHG (CO_{2e} basis) for GHG. GHG are therefore subject to regulation (40 CFR § 52.21(b)(49)(iv)).

VI. Control Technology Review

EPN	Source Name	Best Available Control Technology Description
30-B-05	Boiler 30-B-05	Boiler 30-B-05 is a new boiler with a maximum hourly and annual average fire rates of 462 MMBtu/hr and 420 MMBtu/hr, respectively. The boiler will be fired with refinery fuel gas and/or natural gas. Emissions of NO_X are minimized through the use of ultra-low NO_X burners and SCR. The permit limits NO_X emissions to 0.015 lb/MMBtu fuel fired (HHV basis) on a 1-hr average and 0.015 lb/MMBtu fuel fired on an annual average. Ammonia slip from the SCR is limited to 10 ppmvd (3% O_2 basis) on a 24-hr average. Emissions of CO are limited to 100 ppmvd (3% O_2 basis) on a 1-hr average and 50 ppmvd (3% O_2 basis) on an annual average. SO_2 emissions are limited through use of refinery fuel gas with a maximum H_2S concentration of 87 ppmv on a 1-hour average and 60 ppmv on an annual basis. Emissions of particulate and VOC are limited through good combustion practices and the use of gaseous fuel to maintain opacity less than 5%. VOC emissions will be minimized by maintaining good combustion efficiency and proper combustion design and practices. GHGs from the boiler will be limited through the use of low carbon fuel (refinery fuel gas), good combustion practices, and proper operation and maintenance to achieve a net thermal efficiency of 78%.
121	Heavy Oil Cracker (HOC) Belco Scrubber	The HOC is a type of fluidized catalytic cracking (FCC) unit. SO_2 emissions are limited to 50 ppmvd (0% O_2 basis) on a 1-hr and 7-day rolling average, and 25 ppmvd (0% O_2 basis) on a 365-day rolling average. CO is limited to 500 ppmvd (0% O_2 basis) on a 1-hr average. PM is limited to 1 lb/1000 lbs of coke burned off and opacity is limited to 20% over a 6-minute

EPN	Source Name	Best Available Control Technology Description
		average. VOC emissions are limited to less than 10 ppmv 0% O_2 basis) on a 1-hr average. HCN emissions are limited through compliance with MACT UUU for organic HAPs. H_2SO_4 emissions are limited to 0.35 lb/1000 lb coke burn off. GHG emissions will be limited through work practices consisting of operating the HOC with a high-conversion rate to minimize coke formation. NO_X emissions are limited to 37 ppmvd and (0% O_2 basis) on a 365-day rolling average and limited by using operational practices to reduce NO_X including excess oxygen control and non-Pt combustion promoters. BACT for NO_X was determined using a Tier III analysis, which is detailed in the application, and BACT for all other pollutants was based on a Tier I analysis.
121 30-B-05	Merox vent	This VOC process vent will be routed to the Boiler 30-B-05 firebox or existing SRU tail gas incinerator to achieve a minimum of 99% DRE as specified in the permit special conditions.
HOC-PP-CT	Cooling Tower-Propylene Project	**The Propylene cooling tower is a new non-contact design cooling tower.** The permit requires weekly sampling of cooling water for strippable VOC. Corrective action must be taken if total strippable hydrocarbon content of the cooling water exceeds 0.08 ppmw equivalent, and delay of repair procedures cannot be used if the strippable hydrocarbon content exceeds 0.8 ppmw. The permit requires that particulate emissions be minimized through the drift eliminators which are designed to limit total liquid drift to no greater than 0.001%. Drift eliminators must be inspected regularly and must be repaired or replaced when defects are discovered.
CAS-HOCPP	HOC Gas Plant Wastewater Lift Station	A Carbon Absorption System (CAS) will be installed on the new wastewater lift station in the new Gas Plant to control VOC emissions. The CAS will consist of two adsorbers, connected in series. The outlet of the first adsorber is the breakthrough monitoring point. Breakthrough is defined as 5 ppmv benzene or 100 ppmv VOC at the outlet of the primary canister. If breakthrough is detected, the carbon adsorber is considered spent and must be replaced. When breakthrough is reached on the primary (lead) adsorber, the secondary (lag) adsorber is also monitored at the outlet for breakthrough. If the secondary canister has not broken through, it is moved to the primary position and a fresh adsorber is moved into the secondary position within 24 hours. If the secondary canister has also broken through, then both canisters will be replaced within 24 hours.

EPN	Source Name	Best Available Control Technology Description
21/22F	HOC Unit Fugitives	Fugitive emissions from piping components in VOC service will be monitored using the TCEQ 28VHP and 28CNTQ leak detection and repair (LDAR) programs. These programs will also limit GHG emissions. The piping components in H_2S service will be monitored with the 28AVO LDAR program.
42F	Sour Wtr, Stripper Fugitives	
FUG-CAP	Piping Fugitives	
##F	Selective Hydrogenation Unit, LPG Gas Plant, Boiler 30-B-05	
Various	MSS	The process vessel purge gases will be routed to one of two West Plant flares (EPNs 126 and 158). Valero proposes to flare purge gas from any process vessels that contained liquids with vapor pressures equal or greater than 0.5 psia until a prescribed condition is met. Any residual process liquids and vapors are reduced to the best extent possible via process fluid recovery, followed by flaring before opening the process vessels for inspection and maintenance.
EPN 126 EPN 158	Main Flare Ground Flare	The flares achieve a minimum DRE of 99% for hydrocarbons containing 3 carbon atoms or less, and 98% for all other compounds. The flares are required to comply with 40 CFR § 63.670 specifications for minimum combustion zone net heating value and maximum tip velocity. The flares are equipped with flow monitors and gas chromatograph or calorimeter.

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable, as supplemented by the ADMT, for all review types and pollutants. The results are summarized below.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 1-hr, 24-hr, and annual SO_2, 24-hr and annual $PM_{2.5}$ (NAAQS and Increment), and 1-hr and annual NO_2 exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 3-hr SO_2, 24-hr and annual PM_{10}, and 1-hr and 8-hr CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels is based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda[1,2], the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 NAAQS.

The $PM_{2.5}$ and ozone De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed

[1] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf
[2] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf

source will not cause or contribute to a violation of an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ PSD increments based on the analyses documented in EPA guidance and policy memoranda[3].

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in the table below, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (μg/m³)

Pollutant	Averaging Time	GLCmax (μg/m³)	De Minimis (μg/m³)
SO_2	1-hr	20	7.8
SO_2	3-hr	20	25
SO_2	24-hr	16	5
SO_2	Annual	2	1
PM_{10}	24-hr	4.8	5
PM_{10}	Annual	0.9	1
$PM_{2.5}$ (NAAQS)	24-hr	4	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.8	0.2
$PM_{2.5}$ (Increment)	24-hr	4.7	1.2
$PM_{2.5}$ (Increment)	Annual	0.9	0.2
NO_2	1-hr	30.2	7.5
NO_2	Annual	2	1
CO	1-hr	362	2000
CO	8-hr	319	500

The 1-hr SO_2, 24-hr and annual $PM_{2.5}$ (NAAQS), and 1-hr NO_2 GLCmax are based on the highest five-year averages of the maximum predicted concentrations determined for each receptor. The GLCmax for all other pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

[3] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html

Intermittent guidance was relied on for the 1-hr SO_2 and 1-hr NO_2 PSD De Minimis analyses.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.36 µg/m^3 and 0.01 µg/m^3, respectively. Since the combined direct and secondary 24-hr and annual $PM_{2.5}$ impacts are above the De minimis levels, a full impacts analysis is required.

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O_3	8-hr	0.42	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_x and VOC). For the project NO_x and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. As noted above, the basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Harris County source for NO_x and 1000 tpy Harris County source for VOCs, the applicant estimated an 8-hr O_3 concentration of 0.42 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that the 24-hr SO_2 exceeds the respective monitoring significance level and requires the gathering of ambient monitoring information.

The De Minimis analysis modeling results indicate that 24-hr PM_{10}, annual NO_2, and 8-hr CO are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
SO_2	24-hr	16	13
PM_{10}	24-hr	4.8	10
NO_2	Annual	2	14

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
CO	8-hr	319	575

The GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The applicant evaluated ambient SO_2 and $PM_{2.5}$ monitoring data to satisfy the requirements for the pre-application air quality analysis.

Background concentrations for SO_2 were obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd., Corpus Christi, Nueces County. The applicant used a three-year average (2018-2020) of the 99th percentile of the annual distribution of daily maximum 1-hr concentrations for the 1-hr value (14.5 µg/m^3). The second highest 24-hr concentration from 2020 was used for the 24-hr value (3.1 µg/m^3). The applicant used the 1-hr value and 24-hr value to represent the 3-hr and annual concentrations, respectively. This is conservative. The use of this monitor is reasonable based on the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site and proximity of the monitor to the project site. The 1-hr background value was also used in the PSD NAAQS analysis.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 483550034 located at 5707 Up River Rd., Corpus Christi, Nueces County. The applicant used a three-year average (2018-2020) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (19 µg/m^3). The applicant used a three-year average (2018-2020) of the annual mean concentrations for the annual value (7.7 µg/m^3). The use of this monitor is reasonable based on the applicant's analysis of the surrounding land use and a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site and proximity of the monitor to the project site. The background values were also used in the PSD NAAQS analysis.

Since the project has a net emissions increase of 100 tons per year (tpy) or more of volatile organic compounds or nitrogen oxides, the applicant evaluated ambient O_3 monitoring data to satisfy requirements in 40 CFR 52.21 (i)(5)(i)(f).

A background concentration for O_3 was obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd., Corpus Christi, Nueces County. A three-year average (2018-2020) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (61 ppb). The use of this monitor for a background concentration of ozone is reasonable based on the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site and proximity of the monitor to the project site.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr SO_2, 24-hr and annual $PM_{2.5}$, and 1-hr and annual NO_2 exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	1-hr	151	14.5	166	196
$PM_{2.5}$	24-hr	15	19	34	35
$PM_{2.5}$	Annual	3.6	7.7	11.3	12
NO_2	1-hr	121	34	155	188
NO_2	Annual	23	5	28	100

The 1-hr SO_2 GLCmax is the maximum five-year average of the 99th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted 24-hr concentrations determined for each receptor. The annual $PM_{2.5}$ GLCmax is the maximum five-year average of the predicted annual concentrations determined for each receptor. The 1-hr NO_2 GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The annual NO_2 GLCmax is the maximum predicted concentrations over five years of meteorological data.

The primary NAAQS for 24-hr and annual SO_2 have been revoked for Nueces County and are not reported above.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480391016 located at 109B Brazoria Hwy 332 West, Lake Jackson, Brazoria County. The three-year average (2017, 2018, and 2020) of the 98th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value. The annual concentration from 2020 was used for the annual value. 2019 monitoring data did not meet the completeness criteria. The ADMT reviewed the 2020 design value for Brazoria County, which is based on the highest monitor in the county and determined that this discrepancy would not change the overall conclusions. The use of this monitor is reasonable based on the applicant's analysis of the surrounding land use and a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

As stated above, to evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the 500 tpy Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.36 $\mu g/m^3$ and 0.01 $\mu g/m^3$, respectively. When these estimates are added to the GLCmax listed in Table 4 above, the results are less than the NAAQS.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr and annual SO_2, 24-hr and annual $PM_{2.5}$, and annual NO_2 exceed the respective de minimis concentrations and require a PSD increment analysis.

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (μg/m^3)	Increment (μg/m^3)
SO_2	24-hr	68	91
SO_2	Annual	11	20
$PM_{2.5}$	24-hr	8.9	9
$PM_{2.5}$	Annual	2.9	4
NO_2	Annual	23	25

The GLCmax for the 24-hr SO_2 and 24-hr $PM_{2.5}$ is the maximum high, second high (H2H) predicted concentration across five years of meteorological data. For annual SO_2, NO_2 and annual $PM_{2.5}$, the GLCmax represents the maximum predicted concentrations over five years of meteorological data.

The GLCmax for 24-hr and annual $PM_{2.5}$ reported in the table above represent the total predicted concentrations associated with modeling the direct $PM_{2.5}$ emissions and the contributions associated with secondary $PM_{2.5}$ formation (discussed above in the NAAQS Analysis section).

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 TAC Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Big Bend National Park, is located approximately 550 kilometers (km) from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 3 μg/m^3 occurred approximately 200 meters from the property line towards the north. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 10 km from the proposed sources, in the direction of the Big Bend National Park Class I area is 0.3 μg/m^3. The Big Bend National Park Class I area is an additional 540 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Big Bend National Park Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 5 km from the proposed sources in the direction the Big Bend National Park Class I area. The Big Bend National Park Class I area is an additional 545 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Big Bend National Park Class I area.

F. Minor Source NSR and Air Toxics Review

Table 7. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	183	1021
H_2SO_4	1-hr	9	50
H_2SO_4	24-hr	3	15

Table 8. Generic Modeling Results

Source ID	1-hr GLCmax (µg/m^3 per lb/hr)	Annual GLCmax (µg/m^3 per tpy)
30_B_05	1.74	-
HOCPPCT	7.19	-
121HOC	0.18	-
MEROX	1.74	--
126	0.23	0.004
127	0.23	0.004
158	4.51	0.07
FUGCAP	27.84	-
CASHOCPP	28.93	-

Table 9. Minor NSR Project (Increases Only) Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax (µg/m^3)	10% ESL (µg/m^3)
ammonia 7664-41-7	1-hr	5	18

Pollutant & CAS#	Averaging Time	GLCmax (µg/m³)	10% ESL (µg/m³)
distillates (petroleum), light catalytic cracked 64741-59-9	1-hr	195	350

G. Greenhouse Gases

EPA has stated that unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs, including no PSD increment. The global climate-change inducing effects of GHG emissions, according to the “Endangerment and Cause or Contribute Finding”, are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [EPA’s PSD and Title V Permitting Guidance for GHGs at 48]. Thus, EPA has concluded in other GHG PSD permitting actions it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit.

The TCEQ has determined that an air quality analysis would provide no meaningful data and has not required the applicant to perform one. As stated in the preamble to TCEQ’s adoption of the GHG PSD program, the impacts review for individual air contaminants will continue to be addressed, as applicable, in the state's traditional minor and major NSR permits program per 30 TAC Chapter 116.

VIII. Conclusion

As described above, the applicant has demonstrated that the project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The Executive Director’s preliminary determination is that the permits should be issued.