



ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-2829

BRUCE RAUNER, GOVERNOR

LISA BONNETT, DIRECTOR

217/785-1705

CONSTRUCTION PERMIT/PSD APPROVAL - REVISED
NESHAP SOURCE - NSPS SOURCE

PERMITTEE

Phillips 66 Company
Attn: Brian J. Wulf
900 South Central Avenue
Roxana, Illinois 62084

Application No.: 06050052

I.D. No.: 119090AAA

Date Originally Issued: August 5, 2008

Date Revision Received: August 29, 2013

Date Revision Issued: January 23, 2015

Subject: Coker and Refinery Expansion (CORE) Project

Location: 900 South Central Avenue, Roxana

This Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source(s) and/or air pollution control equipment consisting of the CORE project, that is, various changes to the refinery to increase both the total crude processing and the percentage of heavier crude at the refinery, as described in the above-referenced application. This Permit is subject to standard conditions attached hereto and the following special condition(s):

In conjunction with this permit, approval is given with respect to the federal regulations for Prevention of Significant Deterioration of Air Quality (PSD) for the above referenced project, as described in the application, in that the Illinois Environmental Protection Agency (Illinois EPA) finds that the application fulfills all applicable requirements of 40 CFR 52.21. This approval is issued pursuant to the federal Clean Air Act, as amended, 42 U.S.C. 7401 et seq., the Federal regulations promulgated thereunder at 40 CFR 52.21 for Prevention of Significant Deterioration of Air Quality (PSD), and a Delegation of Authority agreement between the United States Environmental Protection Agency and the Illinois EPA for the administration of the PSD Program. This approval becomes effective in accordance with the provisions of 40 CFR 124.15 and may be appealed in accordance with the provisions of 40 CFR 124.19. This approval is also based upon and subject to the findings and conditions which follow:

If you have any questions on this permit, please contact Jason Schnepf at 217/524-3724.

Raymond E. Pilapil
Acting Manager, Permit Section
Division of Air Pollution Control

Date Signed: _____

REP:JMS:jws

cc: Region 3
Lotus Notes
CES

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1.0 LIST OF ABBREVIATIONS AND ACRONYMS COMMONLY USED

AP-42	<i>Compilation of Air Pollutant Emission Factors, Volume 1, Stationary Point and Other Sources (and Supplements A through F), USEPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711</i>
BACT	Best Available Control Technology
CAAPP	Clean Air Act Permit Program
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
Consent Decree	The Consent Decree captioned "United States of America, State of Illinois, State of Louisiana, State of New Jersey, Commonwealth of Pennsylvania and Northwest Clean Air Agency, Plaintiffs, v. Phillips 66 Company, WRB Refining LLC, Monroe Energy LLC, Defendant," entered in the United States District Court for the Southern District of Texas, Civil Action No. H-05-0258, on December 5, 2005 and amended on May 1, 2007, August 11, 2008, April 13, 2012 and September 21, 2012.
CORE	Coker and Refinery Expansion Project
dscm	Dry standard cubic meters
dscf	Dry standard cubic feet
F	Fahrenheit
FCCU	Fluidized Catalytic Cracking Unit
gr	Grains
H ₂ S	Hydrogen sulfide
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
hr	Hour
IAC	Illinois Administrative Code
I.D. No.	Identification Number of Source, assigned by Illinois EPA
ILCS	Illinois Compiled Statutes
Illinois EPA	Illinois Environmental Protection Agency
Kg	Kilogram
kPa	Kilopascal
LAER	Lowest Achievable Emission Rate
Lb	Pound
LHV	Lower Heating Value
mg	Milligram
Mg	Megagram
MJ/scm	Megajoules per Standard Cubic Meter
Mo	Month
m ³	Cubic meters
mmBtu	Million British Thermal Units
MMGal	Million gallons
MSSCAM	Major Stationary Sources Construction and Modification (35 IAC Part 203), also known as Nonattainment New Source Review (NA NSR)
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO _x	Nitrogen Oxides

NSPS	New Source Performance Standards
O ₂	Oxygen
PM	Particulate Matter
PM ₁₀	Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 microns as measured by applicable test or monitoring methods
PM _{2.5}	Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 microns as measured by applicable test or monitoring methods
ppm	Parts per million
PSD	Prevention of Significant Deterioration (40 CFR 52.21)
psia	Pound per square inch absolute
scf	Standard Cubic Feet
scfm	Standard Cubic Feet Per Minute
SCR	Selective Catalytic Reduction
SO ₂	Sulfur Dioxide
SSMP	Startup, Shutdown, Malfunction Plan
THC	Total Hydrocarbons
TRS	Total Reduced Sulfur
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds (synonymous with VOM)
VOM	Volatile Organic Material
WGS	Wet Gas Scrubber
Yr	Year

2.0 FINDINGS

2.1 Findings for the Revised Permit

- a. Phillips 66 Company (Phillips), formerly ConocoPhillips, applied for various revisions to address:
 - i. Changes to this project due to changes in the composition of the heavy crude oil that the refinery would process with this project. To process the crude oil that is now available, Phillips will now also construct two fractionation columns served by an existing flare, an associated cooling tower, two new product storage tanks, associated piping and components, and a new boiler. It will also modify the Straight Run Deisobutanizer Unit. However, Phillips will no longer bring the Fluid Catalytic Cracking Unit 3, an associated cooling tower, or the Distilling West Gas Plant back into operation. It will also no longer construct two new crude oil storage tanks.
 - ii. Additional control measures for process emissions from the new Delayed Coking Unit, which occur during certain steps in the coking process and from handling of quench water used in the coking process.
 - iii. Process emissions from the new Hydrogen Plant (HP-2), which will occur from vents at this plant under certain operating scenarios.
 - iv. Changes to the utilization of the catalytic reforming units at the refinery, with continued use of CR-1 and CR-3, and the permanent shutdown of CR-2.
 - v. A revised methodology for determining emissions of sulfur dioxide (SO₂) from units that burn refinery fuel gas (RFG), which is based on the total sulfur content of RFG rather than only its hydrogen sulfide (H₂S) content.
 - vi. Corrections to the analysis of the change in emissions of volatile organic material (VOM) at the wastewater treatment plant with this project.
 - vii. Changes to the netting analysis for this project to remove incidental decreases in emissions of particulate, carbon monoxide (CO), SO₂ and VOM that accompanied actions to reduce emissions of nitrogen oxides (NO_x) that were required by a consent decree and to address emissions of H₂S and total reduced sulfur compounds from leaks in the components in piping for process streams and RFG.
 - viii. Changes to permit requirements for the three new cooling towers to reduce water consumption, with a revised limit for the level of total dissolved solids in the cooling

water and accompanying increases in permitted particulate emissions.

- ix. Possible exceedances by process heaters and boilers of the CO standard in 35 IAC 216.121 during startup, malfunction or breakdown, as may be addressed in a permit in accordance with 35 IAC Part 201 Subpart I.
 - x. Various other updates, clarifications and corrections to the terms of the permit.
- b. Phillips has also applied for revisions to a related construction permit (Permit Number 06110049) that address changes at the Hartford Terminal (ID No. 119050AAN), formerly Wood River Products Terminal, that would occur as part of the CORE Project. Phillips will now construct a total of three new storage tanks rather than five, as originally planned for the terminal. Also, no physical changes are planned for the truck loading rack.
- c. With respect to the applicability of MSSCAM, 35 IAC Part 203, to the CORE Project:
- i. This project was originally not subject to MSSCAM for NO_x, PM_{2.5} or SO₂. The requested revisions to the permit will still result in changes in emissions that are less than significant, so it is still not subject to MSSCAM for these pollutants. (See Attachments 1a, 1b and 2.)
 - ii. The requested revisions to this permit will also act to lower the increase in VOM emissions from this project. However, as new units and emission points that would now be part of this project will emit VOM, they are subject to the requirements of MSSCAM for VOM. This is because this project was originally subject to MSSCAM for VOM.
- d. With respect to the applicability of PSD, 40 CFR 52.21, to the CORE Project:
- i. This project was originally not subject to PSD for emissions of SO₂, NO_x, PM or PM₁₀. The requested revisions to this permit will still result in changes in emissions that are less than significant so it is still not subject to PSD for these pollutants. (See Attachments 1a, 1b and 2.)
 - ii. The requested revisions to this permit will also act to lower the increase in CO emissions from this project. However, the new boiler that would now be part of this project will emit CO and is subject to the requirements of PSD for CO. This is because this project was originally subject to PSD for CO.
 - iii. As new units and emission points that would now be part of this project will emit greenhouse gasses (GHGs), they are

subject to requirements of PSD for GHG. This is because GHG is now a regulated pollutant, the requested revisions are subject to PSD for CO (i.e., a pollutant other than GHG), and the potential GHG emissions from the new units and emission points that will now be part of this project would qualify as significant under the PSD rules.

- e. Following review of the requests for revised permits submitted by Phillips, the Illinois EPA determined that the requirements for issuance of revised permits were met, including applicable requirements of MSSCAM and PSD.
- f. In this revised permit, the Illinois EPA has also addressed (i) new state emission standards for NO_x that are applicable to boilers and process heaters at the refinery, 35 IAC Part 217 Subparts D, E and F, (ii) new federal emission standards that are applicable to process heaters, boilers, sulfur recovery plants, fluid catalytic cracking units, coke drums and flares, 40 CFR 60 Subpart Ja, and (iii) new federal standards that are applicable to equipment leaks, 40 CFR 60 Subpart GGGa. The Illinois EPA has also addressed changes made to federal emissions standards that are applicable to process heaters and boilers, 40 CFR 63 Subpart DDDDD.
- g. A copy of Phillips' request for a revised permit, the Illinois EPA's review of this request, and a draft of a revised permit were made available at a location in the vicinity of the refinery and the public was given notice and opportunity to review this material, to submit comments on the proposed revisions, and to request and participate in a public hearing on this matter.

2.2 Findings for the Original Permit

- a.
 - i. ConocoPhillips has requested a permit for various changes to the refinery to increase both the total crude processing and the percentage of heavier crude at the refinery. The name selected by ConocoPhillips for this project is the Coker and Refinery Expansion (CORE) project. A further description of the various changes being made is provided in each of the unit-specific conditions of this permit (Section 4.0).
 - ii. In order to handle the increased product throughput, ConocoPhillips is also proposing certain changes at the Wood River Products Terminal (also owned by ConocoPhillips). A construction permit application (Application Number 06110049) has been submitted for these changes. The Illinois EPA is considering ConocoPhillips' CORE project and the changes to the Wood River Products Terminal to comprise a single larger project for the purpose of PSD/NA NSR.
- b. The Wood River Refinery is located in an area designated nonattainment for ozone and $PM_{2.5}$. For purposes of regulating $PM_{2.5}$, PM_{10} will serve as a surrogate pollutant for $PM_{2.5}$, consistent with current USEPA guidance.
- c.
 - i. This project and the net emissions increase for the source exceeds 40 tons per year of volatile organic material (VOM). The project is therefore subject to 35 IAC 203: Major Stationary Sources Construction and Modification (MSSCAM). (See Attachment 5 of the original permit)
 - ii. This project has potential emissions increases which are more than 100 tons per year of carbon monoxide (CO). The project is therefore subject to PSD review as a major modification for CO emissions. (See Attachment 3 of the original permit)
- d.
 - i. After reviewing all materials submitted by ConocoPhillips, the Illinois EPA has determined that the project will comply with all applicable Board emissions standards and meet the Lowest Achievable Emission Rate (LAER) as required by MSSCAM and Best Available Control Technology (BACT) as required by the PSD rules.
 - ii. A. As some units associated with this project which contribute to a significant increase in emissions do not undergo a physical change or change in the method of operation, these units are not subject to BACT or LAER. These units are further identified in Condition 3.3 (storage tanks with increase in utilization) and Condition 3.4 (debottlenecked heaters and cooling water towers) of this Permit.

- B. In addition to the emission units associated with this project not undergoing a physical change or change in the method of operation, there is no relaxation of any existing federally enforceable emission limits as a result of this project for said units.
- e. The Illinois EPA has broadly considered alternatives to this project, as required by 35 IAC 203.306. Much of the equipment requiring LAER is existing equipment on site which has been idle. Alternative sites would not possess the necessary piping infrastructure, and alternative sizes of equipment would not necessarily meet the consumer demands for gasoline supply. Accordingly, the benefits of the proposed project significantly outweigh its environmental and social costs.
- f. Pursuant to 35 IAC 203.305, the Permittee has demonstrated that all major stationary sources which it owns or operates in Illinois are in compliance or on a schedule for compliance with all applicable state and federal air pollution control requirements, as further identified in Condition 3.2.5 of this permit.
- g. A copy of the application and the Illinois EPA's review of the application and a draft of this permit was forwarded to a location in the vicinity of the plant, and the public was given notice and opportunity to examine this material, to submit comments, and to request and participate in a public hearing on this matter.

3.0 GENERAL SOURCE CONDITIONS

3.1 Project Description

The CORE Project entails various changes to the refinery to increase both the total processing capacity of the refinery and the percentage of heavier crude oil that is processed by the refinery. The following are the key elements of the CORE project:

- New delayed coker unit and associated coker units to convert vacuum residue to clean products and conversion feeds which will enable the processing of higher volumes of heavy crude;
- Metallurgical upgrades and other equipment revisions of Distilling Unit 1 (DU-1) and the addition of a new Vacuum Flasher (VF5) to handle the high acid, high sulfur heavy crudes;
- Restart of the idled Distilling Unit 2 Lube Crude (DU-2 LC) column to provide additional crude unit processing capacity;
- Metallurgical upgrades and other equipment revisions of Fluid Catalytic Cracking Unit 1 (FCCU 1) and Fluid Catalytic Cracking Unit 2 (FCCU 2) to handle the higher acid charge and change in the unit yields, and installation of new wet gas scrubbers (WGS) and selective catalytic reduction (SCR) systems on the flue gas from these units;
- New hydrogen plant;
- Restart of Lube Vacuum Fractionation Column as a Hydrocracker Post-Fractionator (HCF);
- Restart of Catalytic Feed Hydrotreater as an Ultra Low Sulfur Diesel Hydrotreater (ULD-2);
- Additional sulfur processing capacity;
- Additional amine treating and sour water stripping;
- Physical modifications to the wastewater treatment plant;
- Two additional fractionating columns (V-3245 and V-3247)*;
- New gas-fired boiler*;
- Two new product storage tanks*.

* New equipment now being addressed by this revised permit. This revised permit no longer provides for restart of the Distilling West (formerly Premcor) Catalytic Cracking Unit (FCCU 3) and associated equipment.

The key elements listed above and other changes to the refinery as part of this project are further addressed in unit-specific conditions (see Section 4.1 through 4.13). In addition, this permit also accounts for the emissions increases related to the CORE Project that will occur at the Hartford Terminal (ID: 119050AAN), as addressed by Construction Permit 06110049 for a Terminal Expansion Project.

3.2 General Applicable Provisions and Regulations

- 3.2.1 Specific emission units at this source are subject to particular regulations as set forth in Section 4 (Unit-Specific Conditions for Specific Emission Units) of this permit.

3.2.2 In addition, emission units at this source are subject to the following regulations of general applicability:

- a. No person shall cause or allow the emission of fugitive particulate matter from any process, including any material handling or storage activity, that is visible by an observer looking generally overhead at a point beyond the property line of the source unless the wind speed is greater than 40.2 kilometers per hour (25 miles per hour), pursuant to 35 IAC 212.301 and 212.314.
- b. Pursuant to 35 IAC 212.123(a), no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit other than those emission units subject to the requirements of 35 IAC 212.122, except as allowed by 35 IAC 212.123(b) and 212.124.
- c. No owner or operator of a petroleum refinery shall cause or allow a refinery process unit turnaround except in compliance with an operating procedure as approved by the Agency. [35 IAC 219.444(a)]

3.2.3 Emissions Offsets

- a. The Permittee, either alone or coordinated with Phillips' Hartford Terminal, shall maintain 440.1 tons of VOM emission offsets generated by other sources in the St. Louis, Missouri/Metro-East, Illinois nonattainment area such that the total is 1.15 times the VOM emissions increase allowed for this project (i.e., 378* tons of offsets for the permitted increase from the refinery, 328.7 tons/year, and 62.1 tons of offsets for the permitted increase from the terminal, 54.0 tons/year).
- * Note: The total VOM emission increases for the project considering the requested revisions is 329.3 tons/year. Therefore, the originally purchased 440.1 tons of VOM emission offsets remain sufficient for the project with revisions.
- b.
 - i. This VOM emission reduction credit is provided by permanent emission reductions that occurred at the following source, as identified below. These emission reductions have been relied upon by the Illinois EPA to issue this permit and cannot be used as emission reduction credits for other purposes. The reductions at the source identified below have been made enforceable by the withdrawal of the air pollution control permits for the units generating the permanent emission reductions.

JW Aluminum, St. Louis, Missouri
Reduction in VOM Emissions 440.1 tons/year VOM
 - ii. If the Permittee proposes to rely upon emission offsets from another source, the Permittee shall apply for and

obtain a revision to this permit prior to relying on such emission offsets, which application shall be accompanied by detailed documentation for the nature and amount of those alternative emission offsets.

- c. The acquisition of emission offsets shall be completed either 90 days after issuance of this Construction Permit or prior to commencement of construction of the CORE Project, whichever occurs later, unless the Permittee requests an extension and it is approved by the Illinois EPA.

Condition 3.2.3 represents the actions identified in conjunction with this project to ensure that the project is accompanied by emission offsets and does not interfere with reasonable further progress for VOM.

3.2.4 Incorporation of Consent Decree Requirements

This permit addresses certain requirements that apply to the refinery due to the Consent Decree, United States of America, State of Illinois, State of Louisiana, State of New Jersey, Commonwealth of Pennsylvania, Northwest Clean Air Agency v. Phillips 66 Company, WRB Refining LLC, Monroe Energy, LLC (Civil Action No. H-05-258 in the Southern District of Texas on January 27, 2005 and amended on May 1, 2007, August 11, 2008, April 13, 2012 and September 21, 2012.

- a. The Permittee shall eliminate, control, and/or include and monitor as part of the Sulfur Recovery Plant emissions addressed under 40 CFR 60.104(a)(2), all sulfur pit emissions. "Control" for purposes of this condition includes routing sulfur pit emissions into a contactor box of a Beavon Stretford Tail Gas Unit evaporator. [From Paragraph 123 of the Consent Decree]
- b. This permit is issued based on all heaters and boilers at the refinery being affected facilities and fuel gas combustion devices, as those terms are used in the NSPS for Petroleum Refineries, 40 CFR 60 Subpart J. These units are subject to and shall comply with the requirements of the NSPS for Refineries, 40 CFR 60 Subpart J and applicable requirements of the General Provisions of the NESHAP, 40 CFR 60 Subpart A for fuel gas combustion devices. [From Paragraphs 110 and 113 of the Consent Decree]
- c. The Permittee shall not burn fuel oil, that is, any liquid fossil fuel with a sulfur content greater than 0.05% by weight, in any combustion device at the refinery. [From Paragraph 117.a of the Consent Decree]

3.2.5 Schedules for Compliance

All major stationary sources which the Permittee owns or operates (or which are owned or operated by any entity controlling or controlled by, or under common control, with the owner or operator) in Illinois are in

compliance, or on a schedule for compliance, with all applicable state and federal air pollution control requirements. [35 IAC 203.305]

3.3 Nonapplicability Provisions for the Project

3.3.1 PSD/NAA NSR

- a. The Permittee has addressed the applicability and compliance of 40 CFR 52.21, PSD and 35 IAC Part 203, Major Stationary Sources Construction and Modification (MSSCAM). The limits established by this permit are intended to ensure that the project addressed in this construction permit does not constitute a major modification of the refinery pursuant to these rules for NO_x, PM, PM₁₀, PM_{2.5}, and SO₂ emissions (See also Attachments 1a, 1b and 2).
- i. This permit is issued based upon an increase in VOM emissions from storage of additional materials, including crude oil and product as a consequence of the CORE Project of at most 96.8 tons/year.

3.4 General Operational and Emission Limits

3.4.1 Debottlenecked Heaters

- a. The maximum design firing rate of the following existing heaters, which will be "debottlenecked" (i.e., not be physically changed but experience increased firing as a result of the CORE project) shall not exceed the following:

Heater	Firing Rate* (mmBtu/hr)
DU-2 Lube Crude Heater, F-200	151
ULD2 H-1 Process Heater	32
HCF Heater	89.1
HCU-2 Charge Heater	81
HTR-CR1-H1	173
HTR-CR1-H2	218
HTR-CR1-H3	113
HTR-CR1-H4	40
HTR-CR1-H5	37.8
HTR-CR1-H7	60
CR-3 Charge Heater, H-4	420
CR-3 1 st Reheat Heater, H-5	(combined limit)
CR-3 2 nd Reheat Heater, H-6	

* 12-month rolling average, HHV

- b. Emissions from the following heaters shall not exceed the following limits. Compliance with annual limits shall be determined from a running total of 12 months of data.

Heater	NO _x	PM ₁₀	VOM
	Ton/Yr	Ton/Yr	Ton/Yr
DU-2 F-200	181.6	4.9	3.6
ULD2 H-1	6.8	1.0	0.8
HCF Heater	38.3	2.9	2.1
HDU-2 Chg Htr	34.8	2.6	1.9
HTR-CR1-H1	18.2	5.5	4.0
HTR-CR1-H2	22.9	6.9	5.0
HTR-CR1-H3	11.9	3.6	2.6
HTR-CR1-H4	4.2	1.3	0.9
HTR-CR1-H5	4.0	1.2	0.9
HTR-CR1-H7	6.3	1.9	1.4
CR-3 H-4	439.3 (combined limit)	13.7 (combined limit)	9.9 (combined limit)
CR-3 H-5			
CR-3 H-6			

3.4.2 Debottlenecked Cooling Water Tower, Tower CWT-15

- a.
 - i. The total capacity of cooling water tower CWT-15, which will be debottlenecked with an increase in water circulation rate as a result of the CORE project, shall not exceed 8,000 gallons per minute, 12-month rolling average basis.
 - ii. The total dissolved solids content of water circulating in CWT-15 shall not exceed 3,000 ppm on a monthly average basis and 2,520 ppm, 12-month rolling average basis.
 - iii. The design drift loss from the drift eliminators on CWT-15 shall not exceed 0.006 percent, 12-month rolling average basis.
- b. Emissions from cooling water tower CWT-15 shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data:

Unit	PM ₁₀ Emissions		VOM Emissions	
	Tons/Mo	Tons/Yr	Tons/Mo	Tons/Yr
CWT-15	0.19	1.5	0.09	0.7

3.4.3 Debottlenecked Wastewater Treatment Plant Operations

- a. Emissions from the following existing flares, which control certain primary wastewater treatment plant operations shall not exceed the following limits.

Emission Unit	Limits (Tons/Year)	
	NO _x	VOM
WWTP VOC Flare #1	5.4	5.0
WWTP VOC Flare #2	5.4	5.0

Note: Debottlenecked wastewater treatment plant operations are the units that have not been physically changed but experience an

increase in their effective rate due to the removal of capacity limitations on an associated unit.

- b. VOM emission from the wastewater treatment plant, excluding those units that are controlled as addressed above, in total, shall not exceed 19.4 tons/month and 194.0 tons/year.
- c. Compliance with the annual limits shall be determined from a running total of 12 months of data.

3.4.4 New Hydrogen Plant

The total emissions from the new Hydrogen Plant (HP2), including the reformer furnace (HP2 H-1), flare (HP2F), cooling tower (CWT 24), emissions from leaking components and blowdown and high pressure stripper vents shall not exceed the following limits. Compliance with these limits shall be determined from a running total of 12 months of data.

Emissions (Tons/Year)				
CO	NO _x	SO ₂	VOM	PM/PM ₁₀
121.5	245.2	359.8	24.7	46.6

3.5 General Recordkeeping Requirements

3.5.1 Retention and Availability of Records

- a. All records and logs required by this permit shall be retained for at least five years from the date of entry (unless a longer retention period is specified by the particular recordkeeping provision herein), shall be kept at a location at the source that is readily accessible to the Illinois EPA or USEPA, and shall be made available for inspection and copying by the Illinois EPA or USEPA upon request.
- b. The Permittee shall retrieve and print, on paper during normal source office hours, any records retained in an electronic format (e.g., computer) in response to an Illinois EPA or USEPA request for records during the course of a source inspection.

3.5.2 Records Associated With PSD Pollutants From Existing Units

- a. Before beginning actual construction of the project, the Permittee shall document and maintain a record of the following information: [40 CFR 52.21(r)(6)(i)]
 - i. A description of the project;
 - ii. Identification of the emissions unit(s) whose emissions of a regulated PSD pollutant could be affected by the project; and
 - iii. A description of the applicability test used to determine that the project is not a major modification for any

regulated PSD pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under 40 CFR 52.21(b)(41)(ii)(c) and an explanation for why such amount was excluded, and any netting calculations, if applicable.

- b. The Permittee shall keep records for the emissions of any regulated PSD pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in 40 CFR 52.21(r)(6)(i)(b) (See also Condition 3.5.2(a)(ii)) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit that regulated PSD pollutant at such emissions unit. [40 CFR 52.21(r)(6)(iii)]

3.5.3 Records Associated With Nonattainment Area Pollutants From Existing Units With Increase in Utilization

a. Storage Tanks

For the storage tanks for which the increase in utilization approach for determining the change in emissions is being used:

- i. The increase in throughput at the refinery's maximum capacity from the CORE project (gallons/month).
- ii. Emissions of VOM attributable to the increase in throughput (tons/month and tons/year).

3.5.4 Records Associated With Nonattainment Area Pollutants From Debottlenecked Units

a. Heaters

- i. A file listing the maximum rated firing rate of each heater (mmBtu/hr, HHV), with supporting documentation.
- ii. A file showing the potential NO_x, VOM, and PM₁₀ emissions from each heater (tons/year), with supporting calculations and documentation.

b. Cooling Water Tower CWT-15

- i. Cooling water capacity of the tower, expressed in terms of design circulation rate (gallons/minute).
- ii. Emissions of VOM and PM₁₀ from the tower (tons/month and tons/year).

c. Wastewater Treatment Plant Operations

- i. A file showing the potential NO_x and VOM emissions from each flare with supporting calculations and documentation (tons/year).
- ii. Records of the following items for the wastewater treatment plant operations, excluding those units that are controlled by flares:
 - A. Throughput (millions gallons/day).
 - B. VOM emissions (tons/month and tons/year) with supporting calculations and documentation.

3.6 General Reporting Requirements

3.6.1 Records Associated With PSD Pollutants From Existing Units

- a. The Permittee shall submit a report to the Illinois EPA and USEPA if the annual emissions, in tons per year, from the project identified in 40 CFR 52.21(r)(6)(i) (See also Condition 3.5.2(a)), exceed the baseline actual emissions (as documented and maintained pursuant to 40 CFR 52.21(r)(6)(i)(c), by a significant amount (as defined in 40 CFR 52.21(b)(23)) for that regulated PSD pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to 40 CFR 52.21(r)(6)(i)(c). Such report shall be submitted to the Illinois EPA and USEPA within 60 days after the end of such year. The report shall contain the following. [40 CFR 52.21(r)(6)(v)]
 - i. The name, address and telephone number of the major stationary source;
 - ii. The annual emissions as calculated pursuant to 40 CFR 52.21(r)(6)(iii); and
 - iii. Any other information that the Permittee wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

3.6.2 Reporting and Notifications Associated with Performance Tests

- a. The Illinois EPA shall be notified prior to these tests to enable the Illinois EPA to observe these tests. Notification of the expected date of testing shall be submitted a minimum of 30 days prior to the expected date. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days prior to the actual date of the test. The Illinois EPA may at its discretion accept notifications with shorter advance notice provided that the Illinois EPA will not accept such notifications if it interferes with the Illinois EPA's ability to observe testing.

- b. At least 60 days prior to the actual date of testing, a written test plan shall be submitted to the Illinois EPA for review. This plan shall describe the specific procedures for testing, including as a minimum:
 - i. The person(s) who will be performing sampling and analysis and their experience with similar tests.
 - ii. The specific conditions under which testing will be performed, including a discussion of why these conditions will be representative of maximum emissions during normal operation and the means by which the operating parameters for the emission unit and any control equipment will be determined.
 - iii. The specific determinations of emissions and operation, which are intended to be made, including sampling and monitoring locations.
 - iv. The test method(s) that will be used, with the specific analysis method, if the method can be used with different analysis methods.
 - v. Any minor changes in standard methodology proposed to accommodate the specific circumstances of testing, with justification.
- c. Copies of the Final Reports(s) for these tests shall be submitted to the Illinois EPA within 30 days after the test results are compiled and finalized. The Final Report shall include as a minimum:
 - i. A summary of results.
 - ii. General information.
 - iii. Description of test method(s), including description of sample points, sampling train, analysis equipment, and test schedule.
 - iv. Detailed description of test conditions, including:
 - A. Process information, e.g., FCCU feed rate and sulfur content, air blower rate, catalyst recycle rate and coke burn-off rate.
 - B. Control equipment information, e.g., equipment condition and operating parameters during testing, including pressure drop across the wet gas scrubber and the liquid gas rates of the scrubber (the ratio of the scrubbant flow in gallons to the flue gas flow in standard cubic feet, hourly average).

- v. Data and calculations, including copies of all raw data sheets, opacity observation records and records of laboratory analyses, sample calculations, and data on equipment calibration.

3.7 Authorization to Construct and Operate

3.7.1 Construction

- a. This permit shall become invalid if construction is not commenced within 18 months after this permit becomes effective, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable period of time, pursuant to 40 CFR 52.21(r)(2) and 35 IAC 203.113. The Illinois EPA may extend the 18-month period upon a satisfactory showing that an extension is justified. This condition supersedes Standard Condition 1.
- b. For purposes of the above provisions, the definitions of "construction" and "commence" at 40 CFR 52.21 (b)(8)-(9) and 35 IAC 203.113 and 203.116 shall apply, which require that a source must enter into a binding agreement for on-site construction or begin actual on-site construction. (See also the definition of "begin actual construction" and "actual construction" at 40 CFR 52.21(b)(11) and 35 IAC 203.103, respectively.)

3.7.2 Operation

The new/modified emission units addressed by this construction permit may be operated under this permit until renewal of the CAAPP permit provided the source submits a timely and complete CAAPP renewal application.

4.0 UNIT SPECIFIC CONDITIONS FOR SPECIFIC EMISSION UNITS

4.1 Process Heaters

4.1.1 Description

Process heaters will provide heat to various refinery operations. The heaters will burn gaseous fuel, i.e., refinery fuel gas, natural gas, or process off-gas streams. The new heaters will be equipped with ultra low NO_x burners.

Several existing boilers and heaters will be debottlenecked, i.e., the units have not been physically modified but experience an increase in their effective capacity due to the removal of capacity limitations on an associated unit, as a result of this project. These emission increases are accounted for in Section 3 of this permit. One heater, Alky HM-2, will be physically derated by installing new burners that have a maximum firing rate of 99 mmBtu/hr. These new burners are ultra-low NO_x design.

4.1.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
VF5 H350H4	New Vacuum Flasher Process Heater (400 mmBtu/hr)*	Ultra Low NO _x Burners
DCU2 H351H1	New Delayed Coker Unit No. 2 Process Heater (330 mmBtu/hr)*	Ultra Low NO _x Burners
DCU2 H351H2	New Delayed Coker Unit No. 2 Process Heater (330 mmBtu/hr)*	Ultra Low NO _x Burners
DCNH H-1	New Coker Naphtha Hydrotreater No. 2 Process Heater (20 mmBtu/hr)*	Ultra Low NO _x Burners
ULD2 H-2	New Ultra Low Sulfur Diesel No. 2 Process Heater (55 mmBtu/hr)*	Ultra Low NO _x Burners
Alky HM-2	Modified Alkylation Unit Process Heater (99 mmBtu/hr)*; this heater is being derated; ultra low NO _x burners will be installed	Ultra Low NO _x Burners
BEU H3	New Benzene Extraction Unit Process Heater (250 mmBtu/hr)*	Ultra Low NO _x Burners
HP2 H-1	New Hydrogen Plant No. 2 Process Heater (1,275 mmBtu/hr)*	Ultra Low NO _x Burners

* Firing rates listed are 12-month rolling average, in terms of HHV

4.1.3 Applicable Provisions and Regulations

- An "affected heater" for the purpose of these unit-specific conditions, is a heater described in Conditions 4.1.1 and 4.1.2.
- Affected heater Alky HM-2 is subject to the NSPS for Petroleum Refineries, 40 CFR 60 Subpart J and applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A. The

Permittee shall comply with all applicable requirements of 40 CFR 60 Subparts A and J.

- i. The Permittee shall not burn in the affected heater any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf) [40 CFR 60.104(a)(1)].

Note: Pursuant to 40 CFR 60.105(a)(3)(ii), the monitoring level for SO_2 in the exhaust from a heater that is equivalent to the 230 mg/dscm H_2S fuel limit is 20 ppm SO_2 (dry basis, zero percent excess air).

- c. Except for Alky HM-2, the affected heaters are subject to the NSPS for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60 Subpart Ja and applicable provisions of the General Provisions of the NSPS, 40 CFR 60 Subpart A.
 - i. These heaters are subject to 40 CFR 60.102a(g)(1)(ii), which provides that the owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.
 - ii. Except for the DCNH H-1 Heater, these heaters are subject to 40 CFR 60.102a(g)(2)(i)(B), which provides that the owner or operator shall not discharge to the atmosphere any emissions of NO_x in excess of 0.040 lb/MmBtu, HHV basis, determined daily on a 30-day rolling average basis.
- d. The affected heaters are subject to the NESHAP For Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63 Subpart DDDDD and applicable requirements of the General Provisions of the NESHAP, 40 CFR 63 Subpart A. The Permittee shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD.
- e.
 - i. The affected heaters are subject to 35 IAC 216.121, which provides that no person shall cause or allow the emission of carbon monoxide (CO) into the atmosphere from the affected heaters to exceed 200 ppm, corrected to 50 percent excess air [35 IAC 216.121].
 - ii. Notwithstanding the above, subject to the following terms and conditions, the Permittee is authorized to operate the affected heaters in violation of 35 IAC 216.121 during startup. This authorization is provided pursuant to 35 IAC 201.149, 201.161 and 201.262, as the Permittee has applied for such authorization in its application, generally describing the efforts that will be used "...to minimize startup emissions, duration of individual starts, and frequency of startups."

- A. This authorization does not relieve the Permittee from the continuing obligation to demonstrate that all reasonable efforts are made to minimize startup emissions, duration of individual startups and frequency of startups.
 - B. The Permittee shall conduct startup of the affected heaters in accordance with written procedures which shall be maintained at the refinery, that are specifically developed to minimize emissions from startups.
 - C. The Permittee shall fulfill applicable recordkeeping and reporting requirements of Condition 4.1.9(e) and 4.1.10(e).
 - D. As provided by 35 IAC 201.265, this authorization for excess emissions during startup does not shield a Permittee from enforcement for any violation of applicable emission standard(s) that occurs during startup and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.
- f. The affected heaters, except for the DCNH H-1 and ULD2 H-2 heaters, are subject to 35 IAC 217 Subparts D (NO_x General Requirements) and F (Process Heaters).
- i. These heaters are subject to 35 IAC 217.150(e), which provides that the owner or operator shall operate subject heaters in a manner consistent with good air pollution control practice to minimize NO_x emissions.
 - ii. Except for Alky HM-2, these heaters are subject to 35 IAC 217.184, which provides that no person shall cause or allow emissions of NO_x into the atmosphere from the heaters to exceed 0.08lb/mmBtu, on an ozone season and annual average basis.
 - iii. Alky HM-2 is subject to 35 IAC 217.184, which requires annual combustion tuning be performed on the heater as provided in Condition 4.1.5(f).
 - iv. The above requirements take effect beginning January 1, 2015. [35 IAC 217.152(a)]

4.1.4 Nonapplicability Provisions

This permit is issued based on the affected heaters ULD2 H-2 and DCNH H-1 not being subject to the requirements of 35 IAC 217 Subparts D and F. This is because these heaters are subject to federally enforceable limits that restrict NO_x emissions to less than 15 tons per year and

less than five tons per ozone season, in accordance with 35 IAC 217.150(a)(1)(B) and 217.182.

4.1.5 Control Requirements and Work Practices

a. i. BACT/LAER Technology

The affected heaters shall be maintained and operated with good combustion practices to reduce emissions of CO and VOM.

ii. BACT Emission Limit

Emissions of CO from the affected heaters shall not exceed 0.02 lb/mmBtu, HHV, 30-day rolling average.

iii. LAER Emission Limit

Emissions of VOM from the affected heaters shall not exceed 0.003 lb/mmBtu, HHV, 30-day rolling average.

Condition 4.1.5(a)(i) and (ii) represents the application of the Best Available Control Technology. Condition 4.1.5(a)(i) and (iii) represents the application of the Lowest Achievable Emission Rate.

b. The affected heaters shall be equipped, operated, and maintained with ultra low NO_x burners. These burners shall be operated and maintained in conformance with good air pollution control practices.

c. Gaseous fuels, i.e., refinery fuel gas, natural gas, process off-gas streams, or a combination of such fuels shall be the only fuels fired in the affected heaters.

d. Except for Alky HM-2, for the affected heaters, the Permittee shall comply with the requirements of the NSPS, 40 CFR 60.103a, related to SO₂ exceedances, including:

i. Conducting a root cause analysis and a corrective action analysis for each exceedance of an applicable short-term emissions limit in 40 CFR 60.102a(g)(1) if the SO₂ discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter. These analyses must be completed as soon as possible, but no later than 45 days after a discharge meeting this criterion, as further provided by 40 CFR 60.103a(d)(1) and (5). [40 CFR 60.103a(c)(2) and (d)]

ii. Implementing the corrective action(s) identified in the above corrective action analysis in accordance with the

applicable requirements in 40 CFR 60.103a(e). [40 CFR 60.103a(e)]

- e.
 - i. At all times, the Permittee shall operate and maintain the affected heaters, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the USEPA or the Illinois EPA that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.7500(a)(3)]
 - ii.
 - A. The Permittee shall conduct a tune-up of the affected heaters annually as specified in 40 CFR 63.7540. [40 CFR 63.7500 and Table 3]
 - B. The Permittee shall have a one-time energy assessment performed by a qualified energy assessor. [40 CFR 63.7500 and Table 3]
- f. Alky HM-2 is subject to 35 IAC 217.186, Methods and Procedures for Combustion Tuning, which provides that the owner or operator shall have combustion tuning performed on the heater at least annually. The combustion tuning shall be performed by an employee of the owner or operator or a contractor who has successfully completed a training course on the combustion tuning of heaters firing the fuel or fuels that are fired in the heater. For this purpose, the initial combustion tuning of the heater shall be performed by December 31, 2015 (i.e., within one year of the compliance date of January 1, 2015).

4.1.6 Operational and Emission Limits

- a. The maximum design firing rate of the affected heaters shall not exceed the following:

Heater	Firing Rate* (mmBtu/hour)
VF5 H350H4	400
DCU2 H351H1	330
DCU2 H351H2	330
DCNH H-1	20
ULD2 H-2	55
Alky HM-2	99
BEU H3	250
HP2 H-1	1,275

* 12-month rolling average, HHV

- b. Annual emissions from the affected heaters shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data.

Equipment	NO _x (Tons/Yr)	CO (Tons/Yr)	VOM (Tons/Yr)	SO ₂ (Tons/Yr)	PM/PM ₁₀ (Tons/Yr)
VF5 H350H4	70.1	35.0	5.3	112.7	13.1
DCU2 H351H1	57.8	28.9	4.3	93.0	10.8
DCU2 H351H2	57.8	28.9	4.3	93.0	10.8
DCNH H-1	3.5	1.8	0.3	5.6	0.7
ULD2 H-2	9.6	4.8	0.7	15.5	1.8
Alky HM-2	17.3	8.7	1.3	27.9	3.2
BEU H3	43.8	21.9	3.3	70.4	8.2
HP2 H-1	240.1	111.7	16.8	359.2	41.6

- c. Beginning January 1, 2015, NO_x emissions from affected heater ULD2 H-2 shall not exceed 4.9 tons per ozone season (May 1 through September 30 of each year).
- d. NO_x emissions from affected heater Alky HM-2 shall not exceed 0.04 lb/mmBtu on a 12-month rolling average.

4.1.7 Testing Requirements

a. Nitrogen Oxides Testing

- i. Pursuant to 40 CFR 60.7, within 60 days after achieving the maximum production rate at which they will be operated, but not later than 180 days after initial startup, the NO_x emissions of affected heaters VF5 H350H4, DCU2 H351H1, DCU2 H351H2, Alky HM-2, BEU H3 and HP2 H-1 shall be measured during conditions which are representative of maximum emissions during normal operation.
- ii. The following methods and procedures shall be used for testing of emissions, unless another method is approved by the Illinois EPA: Refer to 40 CFR 60, Appendix A for USEPA test methods.

Location of Sample Points	USEPA Method 1
Gas Flow and Velocity	USEPA Method 2
Flue Gas Weight	USEPA Method 3
Moisture	USEPA Method 4
Nitrogen Oxides	USEPA Method 7e or USEPA Method 19

- iii. If the Permittee elects to include Alky HM-2 in an emissions averaging plan pursuant to 35 IAC 217.158, performance testing of NO_x emissions for Alky HM-2 shall be conducted in accordance with 35 IAC 217.157(a)(4), which requires an initial performance test and subsequent performance tests conducted at least once every five years.

b. Hydrogen Sulfide Testing for Alky HM-2

Unless the H₂S content of the fuel gas to the heater is monitored by an existing CEM, in accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the heater will be operated, but not later than 180 days after initial startup of this heater and at such other times as may be required by the Illinois EPA, the Permittee shall conduct performance test(s) in accordance with 40 CFR 60.106(e) and furnish the Illinois EPA a written report of the results of such performance test(s).

c. NSPS Ja Testing Requirements (Excludes Alky HM-2).

For affected heaters except Alky HM-2, the Permittee shall have performance tests conducted for the heaters to demonstrate initial compliance with the applicable emissions limits in 40 CFR 60.102a according to the requirements of 40 CFR 60.8 and 40 CFR 60.104a, as follows. The notification requirements of 40 CFR 60.8(d) apply to the initial performance test, but do not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments. [40 CFR 60.104a(a)]

i. Hydrogen Sulfide Testing

Compliance with the applicable H₂S emissions limit in 40 CFR 60.102a(g)(1) shall be determined according to the test methods and procedures specified in 40 CFR 60.104a(j). Performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance. [40 CFR 60.104a(a) and (j)]

ii. NO_x Testing

Except for DCNH H-1, the owner or operator shall determine compliance with the NO_x emissions limit in 40 CFR 60.102a(g) according to the test methods and procedures in 40 CFR 60.104a(i)(1)-(8).

4.1.8 Monitoring Requirements

a. i. For Alky HM-2, the Permittee shall comply with the applicable monitoring requirements specified in 40 CFR 60.105 by one of the following methods:

A. Installing, calibrating, maintaining and operating an instrument for continuously monitoring and recording the concentration (dry basis) of H₂S in fuel gases before being burned in the heater, or

B. Installing, calibrating, maintaining and operating an instrument for continuously monitoring and recording the concentration of SO₂ emissions into the atmosphere.

C. Notwithstanding the above, pursuant to 40 CFR 60.13(i), after receipt and consideration of written application, the USEPA may approve alternatives to the above monitoring procedures.

ii. For Alky HM-2, the Permittee shall maintain records of the concentration (dry basis) of H₂S in fuel gases before being burned in Alky HM-2 (or SO₂ emissions to the atmosphere, if monitoring is performed according to Condition 4.1.8(a)(ii)) to demonstrate compliance with Condition 4.1.3(b)(i).

Note: Pursuant to 40 CFR 60.105(a)(3)(ii), the SO₂ monitoring level equivalent to the H₂S standard under 40 CFR 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

b. NSPS Ja Monitoring Requirements For Affected Heaters, excluding Alky HM-2.

i. H₂S Monitoring

The Permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gas before being burned in the heaters, as specified in 40 CFR 60.107a(a)(2)(i) through (iv), as applicable. [40 CFR 60.107a(a)(2)]

ii. NO_x Monitoring, excluding DCNH H-1 and Alky HM-2.

A. The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_x emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in 40 CFR 60.107a(d)(1) through (4). [40 CFR 60.107a(d)]

B. Notwithstanding the above, for ULD2 H-2, the Permittee may instead comply with the testing and monitoring requirements in 40 CFR 60.107a(d)(8), which provides that the Permittee shall conduct biennial performance tests according to the requirements in 40 CFR 60.104a(i), establish a maximum excess O₂ operating limit or operating curve according to the requirements in 40 CFR 60.104a(i)(6) and comply with the O₂ monitoring requirements in

paragraphs 40 CFR 60.107a(c)(3) through (5) to demonstrate compliance. [40 CFR 60.107a(d)(8)]

- c. The affected heaters, excluding Alky HM-2, DCON H-1 and ULD2 H-2, are subject to 35 IAC 217.157(a)(3), which provides that the owner or operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system on the heaters for the measurement of NO_x emissions discharged into the atmosphere in accordance with 40 CFR 60 Subpart A and Appendix B, Performance Specifications 2 and 3, and Appendix F, Quality Assurance Procedures, as incorporated by reference in 35 IAC 217.104.

4.1.9 Recordkeeping Requirements

- a. The Permittee shall maintain records of the following items for the affected heaters:
 - i. The firing rate of each affected heater (mmBtu/hr, HHV on a 12 month rolling average), as determined for each month.
 - ii. The total sulfur content of the fuel gas, considering all sulfur compounds in the fuel gas, based on a combination of continuous monitoring for H₂S and periodic sampling and analysis for other sulfur compounds, with supporting documentation.
 - iii. The quantity of each fuel burned (mmBtu/month and mmBtu, total), with supporting documentation including heat content of each fuel gas (Btu/scf).
 - iv. NO_x, CO, VOM, SO₂, PM and PM₁₀ emissions from each affected heater (tons/month and tons/year) with supporting documentation and calculations.
 - v. NO_x emissions (lb/mmBtu, 12-month rolling average) from affected heater Alky HM-2.
- b.
 - i. For the affected heaters except for Alky HM-2, the Permittee shall comply with the applicable recordkeeping requirements in 40 CFR 60.7 and other applicable requirements as specified 40 CFR 60.108a. [40 CFR 60.108a(a)]
 - ii. For Alky HM-2, the Permittee shall comply with the applicable recordkeeping requirements in 40 CFR 60.7 and other requirements as specified 40 CFR 60.107. [40 CFR 60.107(a)]
- c. The Permittee shall comply with the applicable recordkeeping requirements in 40 CFR 63.7555 for the new affected heaters.
- d.
 - i. For each affected heater, except DCON H-1 and ULD2 H-2, the Permittee shall comply with the applicable recordkeeping requirements of 35 IAC 217.156.

- ii. The Permittee shall maintain the records specified in 35 IAC 217.186(a) through (e) for the heater related to this combustion tuning. These records shall be made available to the Illinois EPA upon request. [35 IAC 217.186]
- e. Records for Startup. The Permittee shall maintain the following records for the affected heaters:
 - i. Date and duration of each startup, i.e., start time and time normal operation is achieved.
 - ii. For each startup in which refractory must be cured after maintenance and each other startup if normal operation was not achieved within 6 hours:
 - A. A detailed description of the startup, including whether startup was conducted in accordance with the written procedures required by Condition 4.1.3(e)(ii)(B) and why the startup could have been completed more quickly.
 - B. An explanation why established startup procedures could not be performed, if not performed.
 - C. Whether exceedance of 35 IAC 216.121 may have occurred during startup. If an exceedance may have occurred, an explanation of the severity and duration during the startup and at the conclusion of startup.
 - iii. A maintenance and repair log for the affected heaters, listing each activity performed with date.

4.1.10 Reporting Requirements

- a. The Permittee shall notify the Illinois EPA of deviations of an affected heater with the permit requirements of this section (Section 4.1). Reports shall include information specified in Conditions 4.1.10(a)(i) and (ii). As the operation of affected heaters is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such regulations.
 - i. Emissions from the affected heaters in excess of the limits specified in Condition 4.1.6(b) and (c) within 30 days of such occurrence.
 - ii. Operation of the affected heaters in excess of the limits specified in Condition 4.1.6(a) within 30 days of such occurrence.
- b.
 - i. For the affected heaters, the Permittee shall comply with the applicable notification and reporting requirements in 40 CFR 63.7545 and 63.7550, respectively.

- ii. For affected heater Alky HM-2, the Permittee shall also comply with the initial notification requirements in 40 CFR 63.9(b).
- c.
 - i. For Alky HM-2, the Permittee shall comply with the applicable reporting requirements in 40 CFR 60.107(e) and (f) and 60.105(e)(3).
 - ii. For the affected heaters except Alky HM-2, the Permittee shall comply with the notification and reporting requirements in the NSPS, including 40 CFR 60.7 and 40 CFR 60.108a(a).
- d. For each affected heater, except DCNH H-1 and ULD2 H-2, the Permittee shall comply with the applicable reporting requirements of 35 IAC 217.156 and the applicable initial compliance certification requirements of 35 IAC 217.155.
- e. Reporting of Startups

The Permittee shall submit semi-annual startup reports to the Illinois EPA. These reports may be submitted along with other semi-annual reports required for the source, e.g., CAAPP semi-annual reports, and shall include the following information for startups of the affected heaters during the reporting period:

- i. A list of the startups of each affected heater, including the date, duration and description of each startup, accompanied by a copy of the records pursuant to Condition 4.1.9(e) for each startup for which such records were required.
- ii. If there have been no startups of an affected heater during the reporting period, this shall be stated in the report.

4.2 Delayed Coking Unit 2

4.2.1 Description

A new Delayed Coker Unit (DCU-2) will be installed with the CORE Project. This unit thermally “cracks” heavier components in the crude oil feed to the refinery, splitting longer chain molecules into shorter chain molecules that can be further processed into gasoline and diesel fuel.

This unit will have four drums that operate in pairs, with one drum in each pair in coking service while the other drum is being cooled and emptied. Once a coke drum is full, feed is switched to the other drum of the pair. The full drum is depressurized and the coke in the drum is cooled, first with steam and then with water, before being removed from the drum. During this phase, the exhaust from the coker unit is directed to a closed blowdown system, with a flare gas recovery system (FGRS) sized to collect and recover coke drum vapor for reuse as refinery fuel gas (RFG).

Once the drum is cooled and depressured to less than 2 psig, valves on the top and bottom of the drum are opened in preparation for cutting the coke from the drum and to let water in the drum to drain into the coke pit. The coke is then cut out of the drum with high pressure water lances. This water is collected and reused as quench and cutting water.

There are three aspects of the coking process that result in emissions directly to the atmosphere, as now addressed in this Section 4.2*. Small amounts of VOM, methane, H₂S, and PM are released from the drum vents after they are opened to atmosphere. Cutting the coke releases small amounts of VOM and H₂S. Trace quantities of hydrocarbon that dissolve in the quench and cutting water can also be emitted during subsequent handling of this water.

* In the original permit, Section 4.2 of the permit addressed the Distilling West Cracked Gas Plant. This plant will no longer be brought back into service as part of the CORE Project and is no longer addressed by the revised permit. Section 4.2 now addresses certain direct emissions from the new Delayed Coker Unit, which were not addressed in the original permit.

4.2.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description
Coke Drum Venting	Venting to atmosphere after the coke drum pressure drops to 2 psig
Coke Cutting	Cutting coke from the opened coke drum with water lances
Water Handling	Water system used to supply and recycle quench and cutting water

4.2.3 Applicable Provisions and Emission Standards

- a.
 - i. The DCU-2 coke drum vents are subject to the NSPS for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60 Subpart Ja and applicable provisions of the General Provisions of the NSPS, 40 CFR 60 Subpart A.
 - ii. The DCU-2 coke drum vents are subject to 40 CFR 60.103a(i), which provides that the Permittee shall depressure each coke drum to 5 lb per square inch gauge (psig) or less prior to discharging the coke drum steam exhaust to the atmosphere. Until the coke drum pressure reaches 5 psig, the coke drum steam exhaust must be managed in an enclosed blowdown system and the uncondensed vapor must either be recovered (e.g., sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.

Note: The operational limit in Condition 4.2.5(a) is more stringent than this NSPS limit.

- b. The DCU-2 coke drum vents are subject to 35 IAC 219.441(c)(1), which provides that no person shall cause or allow the discharge of organic material into the atmosphere in excess of 8 lb/hour.

4.2.4 Nonapplicability Provisions

- a. The DCU-2 coke drum vents are not subject to 40 CFR 63 Subpart CC because these vents depressure at or below a coke drum outlet pressure of 15 pounds per square inch gauge, which excludes them from the definition of miscellaneous process vent, pursuant to 40 CFR 63.641.
- b. This permit is issued based on the DCU-2 coke drum vents not being subject to the requirements of 35 IAC 219.143: Vapor Blowdown. This is because the vents are subject to 35 IAC 219.441: Petroleum Refinery Waste Gas Disposal.

4.2.5 Control Requirements and Work Practices

- a. Each coke drum shall be depressured to at least 2 psig or less prior to discharging the coke drum steam vent exhaust to atmosphere. Until the coke drum pressure reaches 2 psig, the coke drum steam exhaust shall be managed in an enclosed blowdown system and the uncondensed vapor shall either be recovered (e.g., sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.
- b. Quench water fill and soak time shall be at least 5.75 hours.
- c. All components and pieces of equipment within the Quench Water System, except the Quench Water Tank shall be hard-piped with no emission points to the atmosphere.

- d. i. Quench water make-up shall only be from one or more of the following sources:
 - A. Water that is fresh, i.e., water brought into the refinery that has not been in contact with process water or process wastewater.
 - B. Non-contact cooling water blowdown.
 - C. Water that has been stripped in a sour water stripper.
- ii. Notwithstanding Condition 4.2.5(d)(i), water from the second half of the quench cycle may be used during malfunction of one or more of the following:
 - A. Distillation Unit 2 sour water concentrator (V-3974)
 - B. Cracked gas plant sour water concentrator (V-3318)
 - C. Distilling West sour water stripper (V-1713)
 - D. Sulfur plant sour water stripper (V-18600)
 - E. Sour Water Tanks M65, 80-6, 1714 and F72.
- e. Oily sludge, oily wastewater, biosolids, or other wastes shall not be fed to any coke drum during the quench cycle.

Note: The above operational requirements for the New Delayed Coker (DCU-2) were determined by the USEPA to be BACT/LAER equivalent technology for emissions from coke drum venting operations, coke cutting operations and water handling operations. (From Paragraph 259 of the Consent Decree)

4.2.6 Emission Limits

Emissions shall not exceed the following limits. Compliance with these limits shall be determined from a running total of 12 months of data.

Operation	GHG (as CO ₂ e)	VOM	H ₂ S	PM
	Tons/Year	Tons/Year	Tons/Year	Tons/Year
Coke Drum Venting	2,500	4.4	3.5	1.1
Coke Cutting	---	2.5	2.0	---
Water Handling	---	1.5	---	---

4.2.7 Recordkeeping Requirements

- a. For each coke drum in the Delayed Coking Unit 2 (DCU-2), the Permittee shall record the drum pressure at the time the drum is first vented to atmosphere during each cycle.

- b. The Permittee shall maintain records of the GHG (as CO₂e), VOM, H₂S, and PM emissions from the coke drums in the Delayed Coking Unit 2 (DCU-2), combined (lbs/month and tons/year).

4.2.8 Reporting Requirements

The Permittee shall notify the Illinois EPA of deviations from the requirements of this section (Section 4.2), as follows. These notifications shall be submitted within 30 days of such occurrence. Reports shall describe the deviation, the probable cause of such deviation, the corrective actions taken, and any preventive measures taken. As the operation of Delayed Coking Unit (DCU-2) is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such regulations.

4.3 Components

4.3.1 Description

As part of the piping and pumping equipment associated with the CORE Project, leaks may occur from components such as valves, connectors, and seals.

4.3.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Components	Components (Connectors, Valves, Pump Seals, Sampling Connections, Drains, Compressor Seals, PRVs)	Leak Detection and Repair (LDAR) Program

4.3.3 Applicable Provisions and Regulations

- a. An "affected component" for the purpose of these unit-specific conditions, is a new component installed as part of the CORE project as described in Conditions 4.3.1 and 4.3.2, and any subsequent replacement of such new component.
- b. The affected components are subject to the NSPS for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60 Subpart GGGa. In particular, components shall comply with the following:
 - i. Pumps in light liquid service are subject to 40 CFR 60.592a(a), which provides that each owner or operator shall comply with the requirements of 40 CFR 60.482-2a as soon as practicable, but no later than 180 days after initial startup.
 - ii. Compressors are subject to 40 CFR 60.592a(a), which provides that each owner or operator shall comply with the requirements of 40 CFR 60.482-3a as soon as practicable, but no later than 180 days after initial startup.
 - iii. Pressure Relief Devices in gas/vapor service are subject to 40 CFR 60.592a(a), which provides that each owner or operator shall comply with the requirements of 40 CFR 60.482-4a as soon as practicable, but no later than 180 days after initial startup.
 - iv. Sampling Connection Systems are subject to 40 CFR 60.592a(a), which provides that each owner or operator shall comply with the requirements of 40 CFR 60.482-5a as soon as practicable, but no later than 180 days after initial startup.
 - v. Valves in gas/vapor service or in light liquid service are subject to 40 CFR 60.592a(a), which provides that each

owner or operator shall comply with the requirements of 40 CFR 60.482-7a as soon as practicable, but no later than 180 days after initial startup.

- vi. Pumps, valves and connectors in heavy liquid service are subject to 40 CFR 60.592a(a), which provides that each owner or operator shall comply with the requirements of 40 CFR 60.482-8a as soon as practicable, but no later than 180 days after initial startup.
- vii. Pressure Relief Devices in light liquid or heavy liquid service are subject to 40 CFR 60.592a(a), which provides that each owner or operator shall comply with the requirements of 40 CFR 60.482-8a as soon as practicable, but no later than 180 days after initial startup.
- viii. Connectors in gas/vapor or light liquid service are subject to 40 CFR 60.592a(a), which provides that each owner or operator shall comply with the requirements of 40 CFR 60.482-8a as soon as practicable, but no later than 180 days after initial startup. (See also 40 CFR 60.593a(g).)

Note: As now provided by this revised permit, the Permittee has elected to comply with the NSPS for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60 Subpart GGGa, for all components at the refinery.

- c. This permit is issued based on the affected components associated with the project being subject to 35 IAC Part 219 Subpart R: Petroleum Refining and Related Industries; Asphalt Materials.

Note: When the requirements for equipment leaks under 40 CFR 60 Subpart GGGa are more stringent than the LDAR requirements in 35 IAC 219.445-452, compliance with 40 CFR 60 Subpart GGGa for the applicable component shall be deemed compliance with 35 IAC 219.445-452.

4.3.4 Nonapplicability of Regulations of Concern

This permit is issued based on the affected components not being subject to the NESHAP for Petroleum Refineries, 40 CFR 63 Subpart CC. This is because equipment leaks that are also subject to the provisions of 40 CFR 60 Subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60 Subpart GGGa, pursuant to 40 CFR 63.640(p)(2).

4.3.5 Control Requirements and Work Practices

- a. LAER Technology for Emissions of VOM. This condition represents the application of the Lowest Achievable Emission Rate.
 - i. Affected components shall comply with the applicable general standards in 40 CFR 63.162 (40 CFR 63, Subpart H)

for components in gas/vapor service, light liquid service, and heavy liquid service, and the following specific standards:

- A. Affected pumps (light liquid service) shall comply with the standards for pumps in light liquid service in 40 CFR 63.163.
 - B. Affected compressors (gas service) shall comply with the standards for compressors in 40 CFR 63.164.
 - C. Affected pressure relief devices (gas/vapor service) shall comply with the standards for pressure relief devices in gas/vapor service in 40 CFR 63.165.
 - D. Affected sampling connection systems shall comply with the standards for sampling connection systems in 40 CFR 63.166.
 - E. Affected open-ended valves or lines shall comply with the standards for open-ended valves or lines in 40 CFR 63.167.
 - F. Affected valves (gas/vapor service and light liquid service) shall comply with the standards for valves in gas/vapor service and in light liquid service in 40 CFR 63.168.
 - G. Affected pumps, valves, and connectors (heavy liquid service) shall comply with the standards for pumps, valves, and connectors in heavy liquid service in 40 CFR 63.169.
 - H. Affected connectors (gas/vapor and in light liquid service) shall comply with the standards for connectors in gas/vapor and in light liquid service in 40 CFR 63.174.
- ii. For affected components, the Permittee shall monitor the component to detect leaks by the method specified in 40 CFR 63.180(b), except that a more stringent definition of a leak shall apply, i.e., an instrument reading of 500 parts per million or greater from valves in gas and light liquid service and an instrument reading of 2,000 ppm or greater from pumps in light liquid service shall be considered a leak.
 - iii. The Permittee shall install the following low emission piping components to units for which construction commences after the issue date of the revised permit:
 - A. Dual mechanical seals for all pumps in gas/vapor or light liquid service as defined by 40 CFR 63.161.

- B. Low emission valves for all valves in gas/vapor or light liquid service as defined by 40 CFR 63.161.
- b. BACT for Emissions of GHG (Methane). This condition represents the application of the Best Available Control Technology.

The Permittee shall comply with the LAER requirements in Condition 4.3.5(a) for control of GHG emissions from affected components that were added or modified as part of this revised permit.

4.3.6 Emission Limits

- a. Emissions of VOM from the affected components shall not exceed 43.0 tons per year. Compliance with this limit shall be determined using published USEPA methodology for determining VOM emissions from leaking components.
- b. This permit is issued based on negligible emissions of GHGs (expressed as CO₂e) from the affected components that were added or modified as part of this revised permit. For this purpose, emissions shall not exceed a nominal emission rate of 50 tons/year, total.
- c. This permit is issued based on negligible emissions of H₂S and TRS from the affected components. For this purpose, emissions of H₂S and TRS shall not exceed 0.3 and 0.5 tons/year, respectively.

4.3.7 Testing Requirements

- a. Leak Detection Methods and Procedures for Affected Components. The Permittee shall comply with the applicable Test Methods and Procedures in 40 CFR 60.485a, pursuant to 40 CFR 60.592a(d).
- b. The Permittee shall repair and retest the leaking components as soon as possible within 22 days after the leak is found, but no later than June 1 for the purpose of 35 IAC 219.447(a)(1), unless the leaking components cannot be repaired until the unit is shutdown for turnaround.

4.3.8 Monitoring Requirements

- a. The Permittee shall develop a monitoring program plan consistent with the provisions of 35 IAC 219.446.
- b. The Permittee shall conduct a monitoring program consistent with the provisions of 35 IAC 219.447.
- c. The Permittee shall identify each affected component consistent with the monitoring program plan submitted pursuant to 35 IAC 219.446.

4.3.9 Recordkeeping Requirements

- a. Recordkeeping Requirements for Affected Components. The Permittee shall comply with the applicable recordkeeping requirements in 40 CFR 60.486a.
- b. The Permittee shall record all leaking components which have a concentration exceeding 10,000 ppm consistent with the provisions of 35 IAC 219.448.
- c. The Permittee shall maintain records of the following items for affected components:
 - i. Number of components by unit or location and type.
 - ii. A. A file containing the maximum VOM emissions of the affected components, including supporting calculations (tons/year). This calculation shall be updated following completion of construction of the CORE project or subsequent changes to the piping to reflect the actual component count.

B. A file containing the maximum GHG (as CO₂e) emissions of affected components that were added or modified as part of this revised permit, including supporting calculations (tons/year). This calculation shall be updated following completion of construction of the CORE project or subsequent changes to the piping to reflect the actual component count.

4.3.10 Reporting Requirements

- a. The Permittee shall notify the Illinois EPA of deviations of an affected component with the permit requirements of this section (Section 4.3). Reports shall describe the probable cause of such deviations, and any corrective actions or preventable measures taken. As the operation of affected components is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such regulations.
- b. Reporting Requirements for Affected Components. The Permittee shall comply with the applicable reporting requirements in 40 CFR 60.487a.
- c. The Permittee shall report to the Illinois EPA consistent with the provisions of 35 IAC 219.449.

4.4 Storage Tanks

4.4.1 Description

New tanks and modifications to an existing tank will be required as a result of the increased throughput and heavier crude slate, as follows:

- An existing storage tank (TK-A126), which has not been in operation for several years, will be reconstructed and restarted to handle the additional ultra low sulfur diesel production from the ULD-2 unit. The tank will be a fixed roof tank design and store ultra low sulfur diesel, which has a low vapor pressure.
- Tank 80-6 will be upgraded by installing a dome on the existing external floating roof. The purpose of the dome is to control potential odors from the tank. This dome effectively converts the external floating roof into an internal floating roof. This tank is used for storage of sour water and sour water concentrate prior to processing at the new sour water stripper at the Sulfur Plant.
- A new methanol tank will be installed at the Wastewater Treatment Plant, to store supplemental feed for the bioorganisms in the activated sludge ponds. This tank will be a fixed roof design.
- Two new product storage tanks (TK-A-033-1 and TK-A-037-1) will be installed to store products from the new fractionating columns. Each tank will have an internal floating roof.

Several existing tanks will experience an increase in utilization as a result of this project. These emission increases are accounted for in Section 3.3.1 of this permit.

Note: This revised permit no longer provides for construction of Tanks A-98 and A-99, which would have stored crude oil, instead providing for construction of Tanks A-033-1 and A-037-1.

4.4.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
TK-A126	New ultra low sulfur diesel storage tank; 5.55 million gallon capacity; fixed roof.	None
Tank 80-6	Sour water storage tank; 3.36 million gallon capacity; Installation of dome on external floating roof (internal floating roof).	Internal Floating Roof
TK-A-033-1	New product storage tank; 83,000 barrel nominal working capacity; internal floating roof.	Internal Floating Roof
TK-A-037-1	New product storage tank; 83,000 barrel nominal working capacity; internal floating roof.	Internal Floating Roof
WWTP Methanol Tank	New methanol storage tank; 10,000 gallon capacity; fixed roof.	None

4.4.3 Applicable Provisions and Regulations

- a. An "affected tank" for the purpose of these unit-specific conditions, is a storage tank described in Conditions 4.4.1 and 4.4.2.
- b. i. The affected tanks TK-A126, TK-A-033-1, TK-A-037-1, and 80-6 are subject to the NESHAP for Petroleum Refineries, 40 CFR 63, Subpart CC and applicable requirements of the General Provisions of the NESHAP, 40 CFR 63 Subpart A.

Note: Affected tank TK-A126 is considered a Group 2 storage vessel under this rule and has no control requirements. Affected tanks TK-A-033-1, TK-A-037-1 and 80-6 are considered Group 1 storage vessels under this rule and therefore require Group 1 controls.

- ii. The methanol tank is subject to the NESHAP for Organic Liquids Distribution, 40 CFR 63 Subpart EEEE and applicable requirements of General Provisions of the NESHAP, 40 CFR 60 Subpart A.

Note: The vapor pressure of methanol is such that no controls are required by this rule.

- c. Affected tanks TK-A-033-1, TK-A-037-1 and 80-6 are subject to the NSPS for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, 40 CFR 60 Subpart Kb and applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A.
- d. The affected tanks are subject to 35 IAC Part 219, Subpart B: Organic Emissions From Storage and Loading Operations.

4.4.4 Nonapplicability of Regulations of Concern

- a. i. This permit is issued based on affected tank A-126 not being subject to the NSPS for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, 40 CFR 60 Subpart Kb, because the affected tank A-126 is a storage vessel with a capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure less than 3.5 kPa. [40 CFR 60.110b(b)]
- ii. This permit is issued based on the affected methanol tank not being subject to the NSPS for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, 40 CFR 60 Subpart Kb, because the affected methanol tank is a storage

vessel with a capacity of less than 75 m³ (19,812.9 gallons). [40 CFR 60.110b(a)]

- b.
 - i. This permit is issued based on affected tanks A-126, TK-A-033-1, TK-A-037-1 and 80-6 not being subject to 35 IAC 219.120 pursuant to 219.119(e) because the affected tanks are only used to store petroleum liquids.
 - ii. This permit is issued based on the affected methanol tank not being subject to 35 IAC 219.120 because the affected methanol tank has a capacity of less than 40,000 gallons.
- c.
 - i. This permit is issued based on affected tank A-126 not being subject to 35 IAC 219.121: Storage Containers of VPL, because the affected tank A-126 will not store a volatile petroleum liquid, i.e., the vapor pressure will be below 1.5 psia.
 - ii. This permit is issued based on the affected methanol tank not being subject to 35 IAC 219.121: Storage Containers of VPL, because the affected methanol tank does not store a volatile petroleum liquid as defined in 35 IAC 211.4610.
- d.
 - i. This permit is issued based on affected tank A-126 not being subject to 35 IAC 219.123: Petroleum Liquid Storage Tanks, because the affected tank A-126 will not store a volatile petroleum liquid, i.e., the vapor pressure will be below 1.5 psia.
 - ii. This permit is issued based on the affected methanol tank not being subject to 35 IAC 219.123: Petroleum Liquid Storage Tanks, because the affected methanol tank has a capacity of less than 40,000 gallons. [35 IAC 219.123(a)(2)]
 - iii. This permit is issued based on affected tanks TK-A-033-1, TK-A-037-1 and 80-6 not being subject to 35 IAC 219.123: Petroleum Liquid Storage Tanks, because affected tanks TK-A-033-1, TK-A-037-1 and 80-6 are subject to 40 CFR 60 Subpart Kb. [35 IAC 219.123(a)(5)]

4.4.5 Control Requirements and Work Practices

- a. LAER Technology. This condition represents the application of the Lowest Achievable Emission Rate.
 - i. A. 1. Affected tank 80-6 shall be controlled by a domed external floating roof, with a primary liquid-mounted seal consistent with the control requirements of 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC and with a secondary rim-mounted seal, except as provided below.

2. Installation of a primary mechanical shoe seal on affected tank 80-6 in place of a primary liquid-mounted seal as required above is allowed, provided all other requirements of Condition 4.4.5(a)(i)(A)(1) are met.
- B. Affected tanks TK-A-033-1 and TK-A-037-1 shall be controlled by an internal floating roof, each with a primary mechanical shoe seal consistent with the control requirements of 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC and with a secondary rim-mounted seal.
 - ii. The true vapor pressure of the material stored in affected tank A-126 shall not exceed 0.09 psia at the maximum monthly average storage temperature.
 - iii. The true vapor pressure of the material stored in the affected methanol tank shall not exceed 3.5 psia at the maximum monthly average storage temperature.
 - b. NSPS Control Requirements: Affected tanks TK-A-033-1, TK-A-037-1 and 80-6 shall be equipped with a fixed roof in combination with an internal floating roof meeting the following specifications:
 - i. The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible. [40 CFR 60.112b(a)(1)(i)]
 - ii. The internal floating roof shall be equipped with a closure device between the wall of the storage vessel and the edge of the internal floating roof in accordance with 40 CFR 60.112b(a)(1)(ii).
 - iii. Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface. [40 CFR 60.112b(a)(1)(iii)]
 - iv. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and

automatic gauge float well shall be bolted except when they are in use. [40 CFR 60.112b(a)(1)(iv)]

- v. Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. [40 CFR 60.112b(a)(1)(v)]
- vi. Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. [40 CFR 60.112b(a)(1)(vi)]
- vii. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening. [40 CFR 60.112b(a)(1)(vii)]
- viii. Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. [40 CFR 60.112b(a)(1)(viii)]
- ix. Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover. [40 CFR 60.112b(a)(1)(ix)]

c. State Control Requirements

- i. Affected tanks TK-A-033-1, TK-A-037-1 and 80-6 shall be designed and equipped with a floating roof which rests on the surface of the VPL and is equipped with a closure seal or seals between the roof edge and the tank wall. Such floating roof shall not be permitted if the VPL has a vapor pressure of 86.19 kPa (12.5 psia) or greater at 294.3 K (70°F). No person shall cause or allow the emission of air contaminants into the atmosphere from any gauging or sampling devices attached to such tanks, except during sampling or maintenance operations. [35 IAC 219.121(b)(1)]
- ii. The affected tanks shall be equipped with a permanent submerged loading pipe, submerged fill, or an equivalent device approved by the Illinois EPA according to the provisions of 35 Ill. Adm. Code 201. [35 IAC 219.122(b)]

4.4.6 Operational and Emission Limits

- a. i. Emissions and operation of the following affected tanks shall not exceed the following limits:

Tank	Throughput		VOM Emissions	
	MMGal/Mo	MMGal/Yr	Ton/Mo	Ton/Yr
A-126	115.0	689.9	1.15	6.9
Methanol	0.02	0.13	0.02	0.1
TK-A-033-1	48.3	289.7	1.6	4.7
TK-A-037-1	48.3	289.7	1.6	4.7

- ii. VOM emissions from affected tank 80-6 shall not exceed 0.07 tons/month and 0.4 tons/year.
- b. Compliance with the annual limits shall be determined from a running total of 12 months of data.

4.4.7 Testing and Inspection Requirements

- a. The Permittee shall comply with applicable testing and procedures requirements of 40 CFR 60.113b(a) for affected tanks TK-A-033-1, TK-A-037-1 and 80-6. [40 CFR 60.113b(a)]
 - i. If the owner or operator determines that it is unsafe to inspect the vessel to determine compliance with 40 CFR 60.113b(a) because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either 40 CFR 63.120(b)(7)(i) or 40 CFR 63.120(b)(7)(ii). [40 CFR 63.640(n)(8)(ii)]
 - ii. If a failure is detected during the inspections required by 40 CFR 60.113b(a)(2), and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the USEPA. [40 CFR 63.640(n)(8)(iii)]
- b. The Permittee shall comply with applicable monitoring of operations requirements of 40 CFR 60.116b for affected tanks TK-A-033-1, TK-A-037-1 and 80-6. [40 CFR 60.116b]

4.4.8 Monitoring Requirements

Monitoring requirements are not set for the affected tanks.

4.4.9 Recordkeeping Requirements

- a. The Permittee shall maintain records of the following items:
 - i. The type, characteristic and quantity of each material stored in each affected tank, including the maximum true vapor pressure.
 - ii. Throughput (million gallons/month and million gallons/year) for each affected tank.

- iii. VOM emissions (tons/month and tons/year) from each affected tank.
- b. The Permittee shall comply with applicable recordkeeping requirements of 40 CFR 60.115b for affected tanks TK-A-033-1, TK-A-037-1 and 80-6.
- c. The Permittee shall comply with applicable recordkeeping requirements of 40 CFR 63.655 for affected tanks TK-A126, TK-A-033-1, TK-A-037-1 and 80-6.
- d. For the methanol tank, the Permittee shall keep documentation, including a record of the annual average true vapor pressure of the total Table 1 (of 40 CFR 63 Subpart EEEE) organic HAP in the stored organic liquid, that verifies the storage tank is not required to be controlled under Subpart EEEE. The documentation must be kept up-to-date and must be in a form suitable and readily available for expeditious inspection and review according to 40 CFR 63.10(b)(1), including records stored in electronic form in a separate location. [40 CFR 63.2343(b)(3)]

4.4.10 Reporting Requirements

- a. The Permittee shall notify the Illinois EPA of deviations of an affected tank with the permit requirements of this section (Section 4.4). Reports shall include information specified in Conditions 4.4.10(a)(i) and (ii). As the operation of affected tanks is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such regulations.
 - i. Emissions from the affected tanks in excess of the limits specified in Condition 4.4.6 within 30 days of such occurrence.
 - ii. Operation of the affected tanks in excess of the limits specified in Condition 4.4.6 within 30 days of such occurrence.
- b. The Permittee shall comply with applicable reporting requirements specified in 40 CFR 60.115b for affected tanks TK-A-033-1, TK-A-037-1 and 80-6.
 - i. Owners and operators of storage vessels complying with 40 CFR 60 Subpart Kb may submit the inspection reports required by 40 CFR 60.115b(b)(4) as part of the periodic reports required by 40 CFR 63 Subpart CC, rather than within the 30-day period specified in 40 CFR 60.115b(b)(4). [40 CFR 63.640(n)(8)(v)]
 - ii. The reports of rim seal inspections specified in 40 CFR 60.115b(b)(2) are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in 40 CFR 60.113b(b)(4). Documentation of the inspections

shall be recorded as specified in 40 CFR 60.115b(b)(3).
[40 CFR 63.640(n)(8)(vi)]

- c. If an extension is utilized in accordance with 40 CFR 63.640(n)(8)(iii), the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in 40 CFR 60.113b(b)(4)(iii), and describe the nature and date of the repair made or provide the date the storage vessel was emptied. [40 CFR 63.640(n)(8)(iv)]
- d. The Permittee shall comply with applicable reporting requirements of 40 CFR 63.655 for affected tanks TK-A126, TK-A-033-1, TK-A-037-1 and 80-6.
- e. The Permittee shall comply with applicable reporting requirements in 40 CFR 63.2343.

4.5 Fluidized Catalytic Cracking Units (FCCU)

4.5.1 Description

The FCCU converts gas-oil, an intermediate weight stream produced in the crude unit at the refinery, into a lighter stream that can be used in production of diesel fuel, gasoline, and other products. The gas-oil is mixed in the FCCU reactor with a finely powdered catalyst, which promotes a cracking reaction to reduce the size of the molecules. During the cracking reaction, carbon is deposited on the catalyst. The catalyst is separated from the cracked products by internal cyclones in the reactor and sent to the regenerator section of the FCCU, where carbon deposited during the reaction is removed by combustion. The carbon free regenerated catalyst is returned to the reactor so that the FCCU operates as a continuous process. The emissions from the FCCU come from the regenerator section.

FCCU 1 and FCCU 2 are considered partial combustion units. A partial combustion unit will have lower regeneration bed temperatures and less oxygen available for combustion. FCCU 1 and FCCU 2 are equipped with separate fuel-fired CO heaters to heat the regenerator vent gas above its ignition temperature. Excess oxygen is supplied to complete conversion of carbon monoxide to carbon dioxide.

Modifications to FCCU 1 include metallurgical upgrades to the feed preheat exchange equipment and the feed piping, internal modification to the fractionator trays, installation of new light-cycle oil cooling, modifications to the high-pressure separator, and CO heater enhancements. Modifications to FCCU 2 include metallurgical upgrades to the feed preheat exchange equipment and the feed piping, internal modification to the fractionator trays, installation of new light-cycle oil cooling, modifications to the high-pressure separator, and CO heater enhancements. Both FCCU 1 and FCCU 2 will be equipped with a wet gas scrubber (WGS) and selective catalytic reduction (SCR). The WGS will control SO₂ and will supplement the existing cyclones used to control particulate matter. SCR will be installed on the existing CO heaters associated with these units to control emissions of NO_x.

4.5.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
FCCU 1	Modified Fluidized Catalytic Cracking Unit (partial combustion unit)	SCR, WGS, CO Heater, Cyclones, Flare
FCCU 2	Modified Fluidized Catalytic Cracking Unit (partial combustion unit)	SCR, WGS, CO Heater, Cyclones, Flare

4.5.3 Applicable Provisions and Regulations

- a. The "affected unit" for the purpose of these unit-specific conditions, is a fluidized catalytic cracking unit described in Conditions 4.5.1 and 4.5.2.
- b. NSPS Ja Provisions

The affected units are subject to the NSPS for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60 Subpart Ja and applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A. In particular, the affected units are subject to 40 CFR 60.102a, Emission Limitations, which provide that an owner or operator shall not discharge or cause the discharge into the atmosphere from any affected unit:

- i. PM in excess of 1 lb/1,000 lb coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected unit. [40 CFR 60.103a(b)(1)(i)]
- ii. NO_x in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis. [40 CFR 60.103a(b)(2)]
- iii. SO₂ in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis. [40 CFR 60.103a(b)(3)]
- iv. CO in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis. [40 CFR 60.103a(b)(4)]

c. NESHAP Provisions

The affected units are subject to NESHAP for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, 40 CFR Part 63, Subpart UUU. The Permittee shall comply with all applicable requirements of 40 CFR Part 63, Subpart UUU.

i. Metal HAP Emissions

The Permittee shall comply with the applicable requirements for metal HAP emissions from catalytic cracking units in 40 CFR 63.1564. In particular, the Permittee shall comply with the emission limitations for NSPS units, pursuant to 40 CFR 63.1564(a)(1).

ii. Organic HAP Emissions

The Permittee shall comply with the applicable requirements for organic HAP emissions from catalytic cracking units in 40 CFR 63.1565. In particular, the Permittee shall comply with the emission limitations for NSPS units, pursuant to 40 CFR 63.1565(a)(1).

d. State Provisions

i. PM Standards

- A. The affected units are subject to 35 IAC 212.381, which provides that the PM emissions from the catalyst regenerators of an FCCU shall not exceed in any one hour period the rate determined using the equations contained in 35 IAC 212.381.
- B. The affected units are subject to 35 IAC 212.123(a), which provides that the emission of smoke or other particulate matter shall not have an opacity greater than 30 percent, except as allowed by 35 IAC 212.123(b) and 212.124.

ii. SO₂ Standards

- A. Except as further provided by 35 IAC 214, no person shall cause or allow the emission of sulfur dioxide into the atmosphere from any affected unit to exceed 2000 ppm. [35 IAC 214.301]
- B. Pursuant to 35 IAC 214.382(c)(3), no person shall cause or allow the total emission of sulfur dioxide into the atmosphere from the following source groupings to exceed the following amounts:

All catalytic cracking units – 3,430 lbs/hour (1,560 kg/hour) [35 IAC 214.382(c)(3)(I)].

Pursuant to 35 IAC 214.382(d), compliance with the above limit shall be demonstrated on a three-hour block average basis.

iii. CO Standards

The affected units are subject to 35 IAC 216.361(b), which provides that the emission of a carbon monoxide waste stream into the atmosphere from any existing petroleum process, as defined in 35 IAC 201.102, using catalyst regenerators of fluidized catalytic converters equipped with in-situ combustion of carbon monoxide, shall not emit CO waste gas streams into the atmosphere in concentration of more than 750 ppm by volume corrected to 50 percent excess air.

iv. VOM Standards

No person shall cause or allow the discharge of organic materials in excess of 100 ppm equivalent methane (molecular weight 16.0) into the atmosphere from any catalyst regenerator of a petroleum cracking system. [35 IAC 219.441(a)(1)]

4.5.4 Nonapplicability of Regulations of Concern

- a. 35 IAC 212.321 and 212.322 shall not apply to catalyst regenerators of fluidized catalytic converters. [35 IAC 212.381]
- b. The affected units are exempt from 40 CFR 63 Subpart CC (Refinery NESHAP) pursuant to 40 CFR 63.640(d)(4).

4.5.5 Control Requirements and Work Practices

- a. i. BACT Technology

The affected units shall be controlled by venting emissions to a CO heater or other combustion device.
- ii. BACT Emission Limit

Emissions of CO from the affected units shall not exceed:

 - A. 100 ppmdv corrected to 0 percent oxygen on a 365 day rolling average; and
 - B. 500 ppmdv corrected to 0 percent oxygen on an hourly average basis.

Condition 4.5.5(a) represents the application of the Best Available Control Technology.

- b. i. LAER Technology

The affected units shall be maintained and operated with good air pollution control practice to reduce emissions of VOM.
- ii. LAER Emission Limit

Emissions of VOM from the affected units shall not exceed 0.05 lb/1000 lb of coke burned.

Condition 4.5.5(b) represents the application of the Lowest Achievable Emission Rate.

- c. i. This permit authorizes the Permittee to install and operate a wet gas scrubber on the affected units.
- ii. This permit authorizes the Permittee to install and operate SCR on affected units.
- d. The Permittee shall comply with the applicable general requirements for affected units identified in 40 CFR 63.1570.
- e. The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in 40 CFR

63.1574(f) and operate at all times according to the procedures in the plan. [40 CFR 63.1564(a)(3) and 40 CFR 63.1565(a)(3)]

f. NSPS Ja Control Device Parameter Operating Limits.

- i. For the wet scrubber, the 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test. [40 CFR 60.102a(c)(2)(i)]
- ii. For the wet scrubber, the 3-hour rolling average liquid-to-gas ratio shall not fall below the level established during the most recent performance test. [40 CFR 60.102a(c)(2)(ii)]

4.5.6 Operational and Emission Limits

- a.
 - i. The daily average coke burn rate of FCCU 1 shall not exceed 540 tons (12-month rolling average).
 - ii. The daily average coke burn rate of FCCU 2 shall not exceed 540 tons (12-month rolling average).
- b.
 - i.
 - A. SO₂ concentrations from the affected units shall not exceed 25 ppmvd on a 365-day rolling average basis and 50 ppmvd on a 7-day rolling average basis, each at 0% O₂. (From Paragraphs 57 and 60 of the Consent Decree.)
 - B. Emissions of PM shall not exceed 0.5 pound PM per 1000 pounds of coke burned on a 3-hour average basis. (From Paragraphs 77 and 81 of the Consent Decree.)
 - C. NO_x concentrations from the affected units shall not exceed 20 ppmvd on a 365-day rolling average basis and 40 ppmvd on a 7-day rolling average basis, each at 0% O₂. (From Paragraphs 27 and 38 of the Consent Decree.)
 - ii. Annual emissions from the affected units shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data:

Unit	Limits (Tons/Year)				
	CO	NO _x	SO ₂	PM/PM ₁₀	VOM
FCCU 1	293.9	96.6	168.1	98.6	9.9
FCCU 2	293.9	96.6	168.1	98.6	9.9

4.5.7 Testing Requirements

a. NSPS Ja Testing Requirements.

For affected units, the Permittee shall have performance tests conducted to demonstrate initial compliance with the applicable

emissions limits in 40 CFR 60.102a according to the requirements of 40 CFR 60.8 and 40 CFR 60.104a, as follows. The notification requirements of 40 CFR 60.8(d) apply to the initial performance test, but do not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments. [40 CFR 60.104a(a)]

- i. For the affected units, the Permittee shall conduct a PM performance test at least once every 12 months and furnish the USEPA and Illinois EPA a written report of the results of each test. [40 CFR 60.104a(b)]
- ii. For the affected units, the Permittee shall use the test methods in 40 CFR 60, Appendices A-1 through A-8 or other methods as specified in this 40 CFR 60.104a, except as provided in 40 CFR 60.8(b). [40 CFR 60.104a(c)]
- iii. For the affected units, the Permittee shall determine compliance with the PM, NO_x, SO₂, and CO emissions limits in 40 CFR 60.102a(b) using the methods and procedures in 40 CFR 60.104a(d)(1) through (8). [40 CFR 60.104a(d)]
- iv. For the affected units, subject to control device operating parameter limits in 40 CFR 60.102a(c), the Permittee shall establish the limits based on the performance test results according to the following procedures: [40 CFR 60.104a(e)]
 - A. Reduce the parameter monitoring data to hourly averages for each test run.
 - B. Determine the hourly average operating limit for each required parameter as the average of the three test runs.
- b. Upon request by the Illinois EPA, the wet gas scrubbers controlling the affected units shall be retested in accordance with applicable test(s) methods as set in Condition 4.5.7.

4.5.8 Monitoring Requirements

- a. The Permittee shall use SO₂, NO_x, CO, and O₂ CEMS to monitor the performance of the affected units. (From Paragraphs 54, 73 and 86 of the Consent Decree)
- b. NSPS Ja Monitoring Requirements
 - i. PM Monitoring.
 - A. The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable

requirements in 40 CFR 60.105a(b)(1)(i) through (iv).
[40 CFR 60.105a(b)(1)]

- B. 1. The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO₂, O₂ (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels.
[40 CFR 60.105a(b)(2)]
- 2. This monitor shall meet the requirements of 40 CFR 60.105a(b)(2)(i)-(iii).

ii. NO_x Monitoring

- A. The affected units are subject to 40 CFR 60.105a(f), which provides that the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere. The monitor shall include an O₂ monitor for correcting the data for excess air.
- B. This monitor shall meet the requirements of 40 CFR 60.105a(f)(1)-(5).

iii. SO₂ Monitoring

- A. The affected units are subject to 40 CFR 60.105a(g), which provides that the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an O₂ monitor for correcting the data for excess air.
- B. This monitor shall meet the requirements of 40 CFR 60.105a(g)(1)-(5).

iv. CO Monitoring

- A. The affected units are subject to 40 CFR 60.105a(h), which provides that the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU subject to the CO emissions limit in 40 CFR 60.102a(b)(4).
- B. This monitor shall meet the requirements of 40 CFR 60.105a(h)(1)-(2).

- v. Excess emissions. For the purpose of reports required by 40 CFR 60.7(c), periods of excess emissions for an affected unit are defined as specified in 40 CFR 60.105a(i)(1) through (6). Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

c. NESHAP Monitoring Requirements

- i. A. Pursuant to 40 CFR 63.1564(a)(2) each affected unit shall be equipped with a continuous opacity monitoring system.
 - B. The Permittee shall install, operate, and maintain these continuous monitoring systems to measure and record the opacity of emissions from each catalyst regenerator vent. [40 CFR 63.1564(b)(1)]
 - C. As an alternative to the requirement to install an opacity monitor, an alternative monitoring plan may be requested from the USEPA to demonstrate compliance with the opacity limits by establishing operating limits for an affected unit as set forth in 40 CFR 63.1564(a)(2).
- ii. A. Pursuant to 40 CFR 63.1565(a)(2) each affected unit shall be equipped with a CO continuous emission monitoring system.
 - B. The Permittee shall install, operate, and maintain these continuous emission monitoring systems to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent. [40 CFR 63.1565(b)(1)]

4.5.9 Recordkeeping Requirements

- a. For the affected units, the Permittee shall comply with the applicable recordkeeping requirements in 40 CFR 60.7 and other applicable requirements as specified in 40 CFR 60.108a.
- b. For the affected units, the Permittee shall comply with the applicable recordkeeping requirements identified in 40 CFR 63.1576.
- c. The Permittee shall maintain records of the following items for affected units:
 - i. Daily coke burn rate for each affected unit (tons).

- ii. Monthly and annual emissions of CO, NO_x, SO₂, PM/PM₁₀ and VOM (tons/month and tons/year) with supporting documentation and calculations.

4.5.10 Reporting Requirements

a. Reporting of Deviations

The Permittee shall notify the Illinois EPA of deviations of an affected unit with the permit requirements of this section (Section 4.5), as follows. Reports shall include information specified in Conditions 4.5.10(a)(i) and (ii). As the operation of affected units is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such regulations.

- i. Emissions from the affected units in excess of the limits specified in Condition 4.5.6(b) within 30 days of such occurrence.
- ii. Operation of the affected units in excess of the limits specified in Condition 4.5.6(a) within 30 days of such occurrence.
- b. For the affected units, the Permittee shall comply with the applicable notification and reporting requirements in 40 CFR 60.7 and other applicable requirements as specified in 40 CFR 60.108a.
- c. For the affected units, the Permittee shall comply with the applicable notification requirements identified in 40 CFR 63.1574.
- d. For the affected units, the Permittee shall comply with the applicable reporting requirements identified in 40 CFR 63.1575.

4.5.11 Compliance Procedures

- a.
 - i. Initial compliance with the NESHAP's metal HAP emission limits shall be demonstrated according to Table 5 of 40 CFR 63 Subpart UUU, pursuant to 40 CFR 63.1564(b)(5).
 - ii. Continuous compliance with the NESHAP's metal HAP emission limits shall be demonstrated according to the methods specified in Tables 6 and 7 of 40 CFR 63 Subpart UUU. [40 CFR 63.1564(c)(1)]
- b.
 - i. Initial compliance with the NESHAP's organic HAP emission limits shall be demonstrated according to Table 12 of 40 CFR 63 Subpart UUU, pursuant to 40 CFR 63.1565(b)(4).
 - ii. Continuous compliance with the NESHAP's organic HAP emission limits shall be demonstrated according to the methods specified in Tables 13 and 14 of 40 CFR 63 Subpart UUU. [40 CFR 63.1565(c)(1)]

4.6 Cooling Water Towers

4.6.1 Description

The cooling water towers are part of the non-contact cooling water systems that circulate water to refinery process units to remove heat from process streams via heat exchangers. The cooling towers "cool" the heated water by means of evaporation allowing the cooling water to be recirculated several times before it is sent to wastewater treatment.

The cooling water towers are sources of particulate matter because of minerals contained in the water, which are emitted if a water droplet completely evaporates in the cooling water tower.

One existing cooling water tower will be debottlenecked as a result of this project. The associated emission increases for this existing cooling water tower are accounted for in Section 3 of this permit.

4.6.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
CWT-23	New North Property Cooling Water Tower	Drift Eliminator
CWT-24	New HP-2 Cooling Water Tower	Drift Eliminator
CWT-25	New cooling water tower for the Sulfur Recovery Units.	Drift Eliminator
CWT-26	New cooling water tower for the new fractionating columns	Drift Eliminator

4.6.3 Applicable Provisions and Regulations

- a. An "affected unit" for the purpose of these unit-specific conditions is a cooling water tower described in Conditions 4.6.1 and 4.6.2.
- b. Pursuant to 40 CFR 63.402, the Permittee shall not use chromium-based water treatment chemicals in any affected unit.
- c. The Permittee shall comply with the monitoring, recordkeeping, and reporting requirements of 35 IAC 219.986(d) as included in Conditions 4.6.8, 4.6.9, and 4.6.10, for each affected unit.
- d. Any affected units that supply cooling water to a process subject to the Hazardous Organic NESHAP, 40 CFR 63 Subpart F (e.g., BEU) shall comply with the heat exchanger system requirements of 40 CFR 63.104.
- e. Except for CWT-24, the affected units are part of heat exchange systems, as defined by 40 CFR 63.641, subject to the NESHAP for Petroleum Refineries, 40 CFR 63 Subpart CC and applicable requirements of the General Provisions of the NESHAP, 40 CFR 63 Subpart A.

4.6.4 Nonapplicability of Regulations of Concern

- a. The LDAR program of Section 4.3 does not apply to the affected units as the towers and piping contain mostly water and are not in VOM service. Appropriate monitoring is addressed in Condition 4.6.8.
- b. This permit is issued based on affected unit CWT-24 not being subject to 40 CFR 63 Subpart CC. This is because the cooling water tower does not service any petroleum refinery process unit heat exchangers in organic HAP service and, therefore, is not considered part of a heat exchange system as defined by 40 CFR 63.641.

4.6.5 LAER Technology

- a. The design drift loss from the drift eliminators on affected units CWT-23, CWT-24, and CWT-25 shall not exceed 0.006 percent, 12-month rolling average.
- b. The design drift loss from the drift eliminators on affected unit CWT-26 shall not exceed 0.005 percent, 12-month rolling average.
- c. The Permittee shall implement a monitoring program for heat exchange systems that meets the provisions of 40 CFR 63.654 for CWT-26.

Condition 4.6.5 represents the application of the Lowest Achievable Emission Rate as required by 35 IAC Part 203.

4.6.6 Operational and Emission Limits

- a. i. The total capacity of the affected units, expressed in terms of design circulation rate, shall not exceed the following limits, hourly average:

Unit	Rate
	Gallons/Minute
CWT-23	50,000
CWT-24	15,000
CWT-25	5,000
CWT-26	12,000

- ii. The total dissolved solids content of water circulating in the affected units shall not exceed 3,000 ppm on a monthly average basis, and 2,520 ppm on an annual average basis.
- b. i. Emissions from the affected units shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data:

Unit	PM Limits		PM ₁₀ Limits		VOM Limits	
	T/Mo	T/Yr	T/Mo	T/Yr	T/Mo	T/Yr
CWT-23	2.1	16.6	1.2	9.2	0.55	4.4
CWT-24	0.7	5.0	0.4	2.8	0.17	1.3
CWT-25	0.3	1.7	0.2	0.9	0.05	0.4
CWT-26	0.5	3.3	0.3	1.8	0.14	1.1

- ii. This permit is issued based on negligible emissions of PM_{2.5} from each affected unit. For this purposes, emissions of PM_{2.5} from each affected unit shall not exceed 0.4 tons/year.

4.6.7 Sampling and Analysis

- a. The Permittee shall sample and analyze the water being circulated in the affected units on at least a monthly basis for the total dissolved solids content. Measurements of the total dissolved solids content in the wastewater discharge associated with the affected unit, as required by a National Pollution Discharge Elimination System permit, may be used to satisfy this requirement if the effluent has not been diluted or otherwise treated in a manner that would significantly reduce its total dissolved solids content.
- b. Upon written request by the Illinois EPA, the Permittee shall promptly have the water circulating in the affected unit sampled and analyzed for the presence of hexavalent chromium in accordance with the procedures of 40 CFR 63.404(a) and (b).
- c. For CWT-23, CWT-25 and CWT-26, the Permittee shall sample and analyze the water in each cooling water return line prior to air exposure. This shall be completed at least monthly for total strippable VOC in accordance with 40 CFR 63.654(c)(3).

4.6.8-1 State Inspection and Monitoring Requirements

The Permittee shall comply with the following control measures for the affected units: [35 IAC 219.986(d)]

- a. The owner or operator of a non-contact process water cooling tower shall perform the following actions to control emissions of VOM from such a tower:
 - i. Inspect and monitor such tower to identify leaks of VOM into the water, as further specified in 35 IAC 219.986(d)(3);
 - ii. When a leak is identified, initiate and carry out steps to identify the specific leaking component or components as soon as practicable, as further specified in 35 IAC 219.986(d)(4);
 - iii. When a leaking component is identified which:

- A. Can be removed from service without disrupting production, remove the component from service;
 - B. Cannot be removed from service without disrupting production, undertake repair of the component at the next reasonable opportunity to do so including any period when the component is out of service for scheduled maintenance, as further specified in 35 IAC 219.986(d)(4);
- iv. Maintain records of inspection and monitoring activities, identification of leaks and leaking components, elimination and repair of leaks, and operation of equipment as related to these activities, as further specified in 35 IAC 219.986(d)(5).
- b. A VOM leak shall be considered to exist in a non-contact process water cooling water system if the VOM emissions or VOM content exceed background levels as determined by monitoring conducted in accordance with 35 IAC 219.986(d)(3)(A).
- c. The owner or operator of a non-contact process water cooling tower shall carry out an inspection and monitoring program to identify VOM leaks in the cooling water system.
 - i. The owner or operator of a non-contact process water cooling tower shall submit to the Illinois EPA a proposed monitoring program, accompanied by technical justification for the program, including justification for the sampling location(s), parameter(s) selected for measurement, monitoring and inspection frequency, and the criteria used relative to the monitored parameters to determine whether a leak exists as specified in 35 IAC 219.986(d)(2).

Note: The above submittal is not required for the affected units if the Permittee elects to implement the monitoring program currently applied at the refinery's existing cooling towers.
 - ii. This inspection and monitoring program for non-contact process water cooling towers shall include, but shall not be limited to:
 - A. Monitoring of each such tower with a water flow rate of 25,000 gallons per minute or more at a petroleum refinery at least weekly and monitoring of other towers at least monthly;
 - B. Inspection of each such tower at least weekly if monitoring is not performed at least weekly.
 - iii. This inspection and monitoring program shall be carried out in accordance with written procedures which the Agency shall specify as a condition in a federally enforceable

operating permit. These procedures shall include the VOM background levels for the cooling tower as established by the owner or operator through monitoring; describe the locations at which samples will be taken; identify the parameter(s) to be measured, the frequency of measurements, and the procedures for monitoring each such tower, that is, taking of samples and other subsequent handling and analyzing of samples; provide the criteria used to determine that a leak exists as specified in 35 IAC 219.986(d)(2); and describe the records which will be maintained.

- iv. A non-contact process water cooling tower is exempt from the requirements of 35 IAC 219.986(d)(3)(B) and (d)(3)(C), if all equipment, where leaks of VOM into cooling water may occur, is operated at a minimum pressure in the cooling water of at least 35 kPa greater than the maximum pressure in the process fluid.
- d. The repair of a leak in a non-contact process water cooling tower shall be considered to be completed in an acceptable manner as follows:
 - i. Efforts to identify and locate the leaking components are initiated as soon as practicable, but in no event later than three days after detection of the leak in the cooling water tower;
 - ii. Leaking components shall be repaired or removed from service as soon as possible but no later than 30 days after the leak in the cooling water tower is detected, unless the leaking components cannot be repaired until the next scheduled shutdown for maintenance.

4.6.8-2 40 CFR 63 Subpart CC Inspection and Monitoring Requirements

- a. Except for CWT-24, the affected units are subject to 40 CFR 63.654(c), which provides that the owner or operator shall perform monitoring to identify leaks of total strippable volatile organic compounds (VOC) from each affected unit subject to the requirements of 40 CFR 63 Subpart CC according to the procedures in 40 CFR 63.654(c)(1) through (6).
- b. Except for CWT-24, the affected units are subject to 40 CFR 63.654(d), which provides that if a leak is detected, the owner or operator shall repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in 40 CFR 63.654(e) and (f). Repair includes re-monitoring at the monitoring location where the leak was identified according to the method specified in 40 CFR 63.654(c)(3) to verify that the measured concentration is below the applicable action level. Actions that can be taken to achieve

repair include but are not limited to the actions identified in 40 CFR 63.654(d)(1)-(5).

- c. Except for CWT-24, the affected units are subject to 40 CFR 63.654(e), which provides that if the owner or operator detects a leak when monitoring a cooling tower return line under 40 CFR 63.654(c)(1)(i), the owner or operator may conduct additional monitoring of each heat exchanger or group of heat exchangers associated with the heat exchange system for which the leak was detected as provided under 40 CFR 63.654(c)(1)(ii). If no leaks are detected when monitoring according to the requirements of 40 CFR 63.654(c)(1)(ii), the heat exchange system is considered to meet the repair requirements through re-monitoring of the heat exchange system as provided in 40 CFR 63.654(d).
- d. Except for CWT-24, the affected units are subject to 40 CFR 63.654(f), which provides that the owner or operator may delay the repair of a leaking heat exchanger when one of the conditions in 40 CFR 63.654(f)(1) or (f)(2) is met and the leak is less than the delay of repair action level specified in 40 CFR 63.654(f)(3). The owner or operator shall determine if a delay of repair is necessary as soon as practicable, but no later than 45 days after first identifying the leak.
- e. Except for CWT-24, the affected units are subject to 40 CFR 63.654(g), which provides that to delay the repair under 40 CFR 63.654(f), the owner or operator shall record the information in 40 CFR 63.654(g)(1) through (4).

4.6.9 Recordkeeping Requirements

- a. The Permittee shall keep records as set forth below for the affected units: [35 IAC 219.986(d)(5)]
 - i. Records of inspection and monitoring activity;
 - ii. Records of each leak identified in such tower, with date, time and nature of observation or measured level of parameter;
 - iii. Records of activity to identify leaking components, with date initiated, summary of components inspected with dates, and method of inspection and observations; and
 - iv. Records of activity to remove a leaking component from service or repair a leaking component, with date initiated and completed, description of actions taken and the basis for determining the leak in such tower has been eliminated. If the leaking component is not identified, repaired or eliminated within 30 days of initial identification of a leak in such tower, this report shall include specific reasons why the leak could not be eliminated sooner including all other intervening periods when the process unit was out of service, actions taken to minimize VOM

losses prior to elimination of the leak and any actions taken to prevent the recurrence of a leak of this type.

- b. The Permittee shall keep records of the total capacity of the affected units (gallons/minute, hourly average).
- c. The Permittee shall keep records of emissions of VOM, PM, and PM₁₀, with supporting calculations (tons/month and tons/year).
- d. For the affected units except for CWT-24, the Permittee shall comply with the applicable recordkeeping requirements of the NESHAP, 40 CFR 63.655.

4.6.10 Reporting Requirements

- a. The Permittee shall notify the Illinois EPA of deviations of an affected unit with the permit requirements of this section (Section 4.6). Reports shall include information specified below. As the operation of affected units is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such regulations.
 - i. Emissions from the affected units in excess of the limits specified in Condition 4.6.6(b) within 30 days of such occurrence.
 - ii. Operation of the affected units in excess of the limits specified in Condition 4.6.6(a) within 30 days of such occurrence.
- b. The owner or operator of a non-contact process water cooling tower shall submit an annual report to the Illinois EPA which provides: [35 IAC 219.986(d)(6)]
 - i. The number of leaks identified in each cooling tower;
 - ii. A general description of activity to repair or eliminate leaks which were identified;
 - iii. Identification of each leak which was not repaired in 30 days from the date of identification of a leak in such a tower, with description of the leaks, explanation why the leak was not repaired in 30 days;
 - iv. Identification of any periods when required inspection and monitoring activities were not carried out.
- c. For the affected units except CWT-24, the Permittee shall comply with the applicable reporting requirements of the NESHAP, 40 CFR 63.655.

4.7 Flares

4.7.1 Description

Two new flares will be installed with the CORE project, one at the new Delayed Coker Unit and one at the new Hydrogen Plant. (The operation and emissions of existing flares at the refinery, which are not modified under New Source Review regulations, are addressed in Condition 3.4.3). The existing Distilling Flare would be modified by installing additional piping to control emergency relief for two new columns, V-3245 and V-3247. Venting would occur during depressurization to ensure safe operation of process units.

The new and modified flares are safety devices to dispose of combustible gases that are vented from the associated processing units due to equipment malfunctions, process upsets or other conditions that prevent the vented gases from being recovered for use of fuel at the refinery. Most releases of combustible gases will be such that they can be recovered and used as fuel at the refinery, rather than being flared. Only the releases that cannot be recovered would be sent to a flare, to be combusted in a burner system that has been designed for safe and effective combustion of the large release of flammable gas that can occur during an equipment malfunction or process upset. Combustion of those releases in the flare would convert the organic compounds, hydrogen and sulfur compounds in the releases into water, carbon dioxide and SO₂.

The Permittee must take measures to recover most of the process gases generated by the associated processing units and reduce the amount of vented gas that is flared. To prevent the routine flaring of vent gas from the new Delayed Coker Unit, two gas recovery compressors would be installed to collect gas generated by the coking process and send it to the fuel gas treatment system for removal of sulfur compounds in preparation for being used as fuel at the refinery. The second compressor would be a spare, as the capacity of each gas recovery compressor must be sufficient for at least 100 percent of the routine gas flow from this unit. Emergency flaring at the Delayed Coker Unit would be reduced through preparation and implementation of a Flaring Minimization Plan to ensure that this unit is operated and maintained in a manner that minimizes emergency conditions that could lead to flaring. Event-specific Root Cause Analysis would also be conducted for significant flaring events that do occur, to identify the underlying cause(s) for such flaring and enable actions to be taken to reduce the likelihood of or prevent similar flaring events in the future.

The design of the Hydrogen Plant would directly minimize flaring of gas vented from this plant. This plant normally operates using the byproduct gas generated by the Pressure Swing (PS) Absorbers, which purify the hydrogen made by the plant, as the fuel for the reformer furnace in the plant. Because of the design of hydrogen plants, the gas from the PS Absorber can normally be directly used as the fuel for the reformer furnace without first having to undergo de-sulfurization and without need for gas recovery compressors. However, during

startup, when the heat content of the gas from the PS Absorbers is variable and outside the normal range, this gas is flared because it cannot be safely used as fuel in the furnace. This flaring would be minimized as the Hydrogen Plant is designed to operate for several years between scheduled outages for maintenance. Flaring associated with the new Hydrogen Plant must also be reduced through preparation of a Flaring Minimization Plan and performance of Root Cause Analyses for significant flaring events that do occur.

During normal operation of the new Delayed Coker Unit and the Hydrogen Plant, the only emissions from the associated flares would be from combustion of the natural gas and refinery fuel gas used as pilot gas and purge gas in the flares. To address this aspect of operation of the flares, unit-specific limitations are set on the total amount of pilot and purge gas used by each flare.

As these flares would at times combust gases vented from the associated units under conditions when a release of gas cannot be recovered, the flares must comply with applicable federal standards for proper design and operation of a flare for efficient destruction of organic compounds and minimize formation of carbon monoxide.

4.7.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description
DCUF	New Delayed Coker Unit Flare, Steam-Assisted Flare
HP2F	New Hydrogen Plant Flare, Steam-Assisted Flare
Distilling Flare	Modified Distilling Flare, Steam-Assisted Flare

4.7.3 Applicability Provisions and Emission Standards

- a.
 - i. An "affected flare" for the purpose of these unit-specific conditions is a flare described in Conditions 4.7.1 and 4.7.2.
 - ii. An "affected plant" for the purpose of these unit-specific conditions is a plant served by an affected flare, i.e., the new Delayed Coker Unit, the new Hydrogen Plant or new columns connected to the Distilling Flare (V-3245 and V-3247), as described in Conditions 4.7.1 and 4.7.2.
- b. The affected flares are subject to New Source Performance Standards (NSPS) for Petroleum Refineries, 40 CFR 60 Subpart Ja and applicable requirements of the General Provisions, 40 CFR 60 Subpart A.
 - i. Flare Management Plan
 - A. The affected flares are subject to 40 CFR 60.103a(a), which provides that the owner or operator shall develop and implement a written Flare Management Plan upon startup of an affected flare. The flare management plan must include the information described in 40 CFR 60.103a(a)(1) through (7).

- B. The Permittee shall submit the Flare Management Plan to the USEPA and Illinois EPA as described in 40 CFR 60.103a(b)(1) through (3), pursuant to 40 CFR 60.103a(b).

ii. Root Cause Analysis and Corrective Action Analysis

- A. The affected flares are subject to 40 CFR 60.103a(c), which provides that the owner or operator shall conduct a Root Cause Analysis and a Corrective Action Analysis for each of the conditions specified below:
 - 1. Any time the SO₂ emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or
 - 2. Any discharge to the flare in excess of 14,160 standard cubic meters (m³) (500,000 standard cubic feet (scf)) above the baseline, determined in 40 CFR 60.103a(a)(4), in any 24-hour period.
- B. The Root Cause Analysis and Corrective Action Analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in above (40 CFR 60.103a(c)). Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in 40 CFR 60.103a(d)(1) through (5).
- C. The affected flares are subject to 40 CFR 60.103a(e), which provides that the owner or operator shall implement the corrective action(s) identified in the Corrective Action Analysis in accordance with the applicable requirements in 40 CFR 60.103a(e)(1) through (3).

iii. H₂S Concentration Limit

The affected flares are subject to 40 CFR 60.103a(h), which provides that the owner or operator shall not burn in any affected flare any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit.

iv. Compliance Dates

For the modified Distilling Flare, the Permittee shall comply with (i) the requirements of 40 CFR 60.103a(c) through (e) by November 11, 2015 or at startup of the

modified Distilling Flare, whichever is later; (ii) the requirements of 40 CFR 60.103a(h) and the requirements of 40 CFR 60.107a(a)(2) by no later than November 11, 2015; and (iii) the requirements of 40 CFR 60 Subpart J as specified in the Consent Decree until November 10, 2015. [40 CFR 60.103a(f)]

- c. The affected flares are subject to General Control Device Requirements of the NSPS, 40 CFR 60.18, which for flares provides that:
- i. Flares shall be designed for and operated with no visible emissions as determined by the methods specified in 40 CFR 60.18(f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [40 CFR 60.18(c)(1)]
 - ii. Flares shall be operated with a flame present at all times, as determined by the methods specified in 40 CFR 60.18(f). [40 CFR 60.18(c)(2)]
 - iii. A source has the choice of adhering to either the heat content specifications in 40 CFR 60.18(c)(3)(ii) and the maximum tip velocity specifications in 40 CFR 60.18(c)(4), or adhering to the requirements in 40 CFR 60.18(c)(3)(i). [40 CFR 60.18(c)(3)]
 - iv.
 - A. Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in 40 CFR 60.18(f)(4), less than 18.3 m/sec (60 ft/sec), except as provided in 40 CFR 60.18(c)(4)(ii) and (iii). [40 CFR 60.18(c)(4)(i)]
 - B. Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in 40 CFR 60.18(f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf). [40 CFR 60.18(c)(4)(ii)]
 - C. Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in 40 CFR 60.18(f)(4), less than the velocity, V_{max} , as determined by the method specified in 40 CFR 60.18(f)(5), and less than 122 m/sec (400 ft/sec) are allowed. [40 CFR 60.18(c)(4)(iii)]
 - v. Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max} , as determined by the method specified in 40 CFR 60.18(f)(6). [40 CFR 60.18(c)(5)]

- vi. Flares used to comply with this 40 CFR 60.18 shall be steam-assisted, air-assisted, or nonassisted. [40 CFR 60.18(c)(6)]
- vii. Sources shall monitor flares to ensure that they are operated and maintained in conformance with their designs, with specific monitoring conducted in accordance with the relevant provisions of applicable subparts of the NSPS. [40 CFR 60.18(d)]
- viii. Flares shall be operated at all times when emissions may be vented to them. [40 CFR 60.18(e)]
- d.
 - i. The affected flares are subject to 35 IAC 214.301, which provides that no person shall cause or allow the emission of sulfur dioxide into the atmosphere from any process emission unit to exceed 2,000 ppm.
 - ii. Notwithstanding the above, subject to the following terms and conditions, the Permittee is authorized pursuant to 35 IAC 201.149 and 201.262 to continue operation of an affected flare for the new Delayed Coker Unit in violation of the standard in 35 IAC 214.301 during malfunction or breakdown of equipment venting to this flare:
 - A. This authorization only allows such continued operation as necessary to prevent hazard to persons or severe damage to equipment or to provide essential services and does not extend to continued operation solely for the economic benefit of the Permittee.
 - B. Upon occurrence of excess emissions due to malfunction or breakdown, the Permittee shall as soon as practicable reduce equipment load, repair equipment, remove equipment from service or undertake other action so that excess emissions cease.
 - C. The Permittee shall fulfill applicable recordkeeping and reporting requirements of Conditions 4.7.9(f) and 4.7.10(c), pursuant to 35 IAC 201.149.
 - D. Following notification to the Illinois EPA of a malfunction or breakdown with excess emissions, the Permittee shall comply with all reasonable directives of the Illinois EPA with respect to such incident, pursuant to 35 IAC 201.263.
 - E. This authorization does not relieve the Permittee from the continuing obligation to minimize excess emissions during malfunction or breakdown. As provided by 35 IAC 201.265, an authorization in a permit for continued operation with excess emissions during malfunction or breakdown does not shield the

Permittee from enforcement for any such violation and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

- e. The affected vents are subject to 35 IAC 219.441(c)(1), which provides that no person shall cause or allow the discharge of organic material into the atmosphere in excess of 8 lb/hour from any waste gas stream from any new petroleum manufacturing process, other than a catalyst regenerator or fluid coker, unless emissions are controlled by at least 85 percent.

4.7.4 Nonapplicability of Regulations of Concern

For the Delayed Coking Unit and Hydrogen Plant flares, the Permittee is not required to comply with applicable substantive requirements of the NSPS, 40 CFR 60 Subpart Ja, as adopted by USEPA on June 24, 2008 (73 FR 35838 et seq.), as was originally required by Condition 4.7.5-1(a)(x). Rather, the Permittee is required to comply with the current version of 40 CFR Subpart Ja (See Condition 4.7.3(b)). This is because, the Illinois EPA has determined that the substantive requirements of the NSPS subsequently adopted by USEPA on September 12, 2012 are equivalent to or provide for more stringent control of emissions than the requirements adopted on June 24, 2008, and that implementation of the earlier requirement, as well as the adopted requirement, would be inconsistent or impractical

4.7.5-1 Control Requirements and Work Practices

- a. BACT/LAER Technology
 - i. The affected flares shall be operated and maintained to comply with all applicable requirements for flares in the NSPS, 40 CFR 60.18.
 - ii. The only gases combusted in the affected flares serving an affected plant shall be the following. This provision does not restrict the flow of air or steam or other noncombustible gases to the affected flares.
 - A. Process upset gases (as defined in 40 CFR 60.101a), including relief valve leakage due to malfunction; and
 - B. Gaseous fuels meeting the requirements of 40 CFR 60.102a(g)(1)(ii), which shall only be used as pilot or purge gas; combusted in response to a fuel gas imbalance as addressed by 40 CFR 60.102a(i); for the Hydrogen Plant, combusted during periods when the fuel gas composition would be incompatible with its safe use in the furnace or device in which it is normally used; combusted for the purpose of maintaining a minimum heating value in the gas vented

to the unit; or combusted for the purpose of verifying the operational capability of the unit.

iii. The affected Delayed Coker Unit shall be designed, operated and maintained with a flare gas recovery system with redundant compressor capacity, i.e., a system with two or more flare gas recovery compressors whose capacity is each sufficient to handle the normal range of gas generated from operation of this Unit (including startup and shutdown), even when one compressor is not in service, as may occur with routine preventative maintenance of compressors.

iv. [Reserved]

Note: Former Condition 4.7.5-1(a)(iv) is now addressed by Condition 4.2.5(a).

v. Flaring associated with the affected plants, including flaring due to all causes, shall be minimized by operating and maintaining the affected units and affected plants, including the associated flare gas recovery systems, in accordance with a Flaring Minimization Plan (Plan) in accordance with Condition 4.7.5-2, which Plan may be consolidated with other plans required for the affected plants, such as the turnaround plan required by 35 IAC 219.444(b).

vi. The Permittee shall conduct an event-specific investigation or "Root-Cause Analysis" into each Hydrocarbon Flaring Incident at an affected plant to determine the causes of the incident, to take reasonable steps to correct the conditions that caused or contributed to such incident, and to further minimize emissions from flaring, which investigation shall be conducted in accordance with Condition 4.7.5-3. For this purpose, a Hydrocarbon Flaring Incident is defined as a flaring event (i.e., the flaring of vent gas from an affected plant) that involves 100,000 scf or more of gas or results in VOM emissions of 50.0 or more pounds in a period of 24 hours or less. For this purpose, VOM emissions from the new affected flares shall be determined in accordance with Attachment 4, Procedures for Calculating CO and VOM Emissions from New Flares.

vii. The total flow of pilot and purge gas to the new affected flares shall not exceed the following limits:

A. Delayed Coker Unit Flare - 80,000 scf per day, 30-day rolling average.

B. Hydrogen Plant Flare - 98,000 scf per day, 30-day rolling average.

- viii. The Permittee shall equip, operate and maintain each affected flare with an automatic igniter device for the pilot flame, which device shall be maintained in good working order.
- ix. The Permittee shall conduct acoustical or temperature leak surveys for all pressure relief devices connected directly to an affected flare serving an affected plant (rather than vented through a seal drum) and repair leaking pressure relief devices no later than the next turnaround in which such relief device may be repaired. Such surveys shall be conducted annually, with a survey conducted no more than 90 days before any scheduled turnaround of the affected plant or units in which such relief device may be repaired.

Condition 4.7.5-1(a) represents the application of the Best Available Control Technology (BACT) and the application of the Lowest Achievable Emission Rate (LAER).

- b. The emissions of CO from each new affected flare shall not exceed the annual limits for CO in Condition 4.7.6(a) and (b). For the purpose of determining compliance with these limits, emissions of CO shall be determined in accordance with Attachment 4, Procedures for Calculating CO and VOM Emissions from New Flares, with annual emissions_determined from a running total of 12 months of data.

Condition 4.7.5-1(b) sets "secondary" BACT limits for CO emissions to accompany the work practices established as BACT in Condition 4.7.5-1(a).

- c. The Permittee shall not vent any gas stream containing reduced sulfur compound concentrations to an affected flare that would cause the SO₂ emissions into the atmosphere from the unit to exceed 2,000 ppm, except as allowed by Condition 4.7.3(d)(ii). This requirement ensures that the affected flares meet the emission standard of 35 IAC 214.301.

4.7.5-2 Flaring Minimization Plan

- a. The Flaring Minimization Plan (Plan) prepared by the Permittee for each affected plant pursuant to Condition 4.7.5-1(a)(v) shall include the following:
 - i. Technical information for the affected plant, including a general description of the affected plant, including the flare gas recovery system(s), with the capacity of each system and individual gas recovery compressor; process flow diagram(s) depicting all process units and flare gas recovery system(s) (including each compressor) in the plant; detailed process flow diagram(s) for the affected flare, including vent gas lines, knockout pots, surge drums, seal drums, and other significant components of the affected flare; and a description of the monitoring systems

and process controls for the affected flare, including a diagram showing each location at which a measurement is made or a sample would be taken.

- ii. A description of the Permittee's written operating procedures for the normal operation of the affected plant, including recovery of gases vented from the Delayed Coker Unit for use as fuel during startup and shutdown.
- iii. A detailed description of the established responsibilities of different personnel at the refinery for the operation and maintenance of the affected plant.
- iv. A detailed description of the Permittee's procedures for flaring due to occurrence of process upsets or equipment failures or other reasons, including provisions in these procedures that act to minimize flaring.
- v. A detailed description of the Permittee's procedures to minimize flaring in conjunction with major maintenance and turnarounds of the affected plant, including the planning conducted as part of such work to minimize flaring.
- vi. For the Delayed Coker Unit, a detailed description of the Permittee's procedures for the fuel gas systems to facilitate acceptance of vent gas from this plant and to maintain or restore recovery of vent gas during flaring events.
- vii. A detailed description of the Permittee's procedures for preventative maintenance of the affected plant, including provisions in these procedures that should act to minimize flaring.
- viii. A detailed description of the Permittee's procedures for periodic evaluation of flaring activity generally and specific evaluation of flaring incidents, including both identification of the causes of flaring, assessment of measures to eliminate or reduce such flaring, and implementation of feasible measures to reduce flaring.
- ix. A comparison with the practices for flare minimization and the levels of flaring achieved for similar units and plant-wide at other petroleum refineries operated by the Permittee or by other companies that are required to prepare flaring minimization plans, including a comparison of compressors, flare gas recovery systems, other equipment, work practices, and root cause feedback mechanisms used to make ongoing progress in minimizing flaring.
- x. An evaluation of preventative measures to reduce the occurrence and magnitude of flaring for the affected plant, including a schedule for the expeditious implementation of

all feasible prevention measures to address the following, including consideration of past flaring activity as information for actual operation of the plant becomes available:

- A. Flaring that could reasonably be expected to occur or has occurred during startup, shutdown and planned maintenance activities. The evaluation shall include a review of flaring that has occurred during these activities in the past five years, with the objective of performing these activities without any flaring of vent gas.
 - B. Flaring that could reasonably be expected to occur or has occurred due to issues of gas quantity and quality. The evaluation shall include an audit of the vent gas recovery capacity of the flare system, the storage capacity available for excess vent gases, and the scrubbing capacity available for vent gases including any operational constraints for treatment of vent gases for use as a fuel; and shall consider the feasibility of reducing flaring through the enhanced recovery, treatment and use of the gas or other means.
 - C. Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall consider the adequacy of existing maintenance schedules and protocols for such equipment. For this purpose, a failure is recurrent if it occurs more than twice during any five year period as a result of the same cause.
- xi. After the affected plant has begun operation, a description of additional equipment, processes, procedures or other measures that are installed or implemented to reduce flaring from the plant, which addresses the following:
- A. Measures taken within the last five years to reduce flaring, which shall specify the year of installation or implementation of each measure.
 - B. Measures that are planned, which shall specify the year in which operation or implementation of each planned measure is scheduled.
- b. i. The Permittee shall submit a copy of the Plan to the Illinois EPA for review and comments at least 90 days prior to initial startup of an affected plant.
- ii. The Permittee shall review the Plan on at least an annual basis and revise the plan so that it is kept current and reflects any changes in the configuration or operation of

the affected plant or significant changes in the nature of the vent gas that is flared.

- iii. The Permittee shall make changes to the Plan for a plant if required by the Illinois EPA or USEPA to address an apparent deficiency identified in the Plan or as otherwise needed to address apparent or possible deficiencies in the Plan identified by the Permittee.
- iv. These Plans are records required by this permit, which the Permittee must retain and make available to the Illinois EPA and USEPA in accordance with the general requirements for retention and availability of records. In addition, when the Permittee revises the Plan, the Permittee must also retain and make available the previous (i.e., superseded) version of the Plan for a period of at least 5 years after such revision.
- v. In addition to being certified for truth, accuracy and completeness by the responsible official for the source, if the responsible official for the source does not possess sufficient authority to undertake all actions needed for compliance with the Plan, copies of Plans submitted to the Illinois EPA shall also be certified by a representative of the Permittee that has such authority.

4.7.5-3 Requirements for Root Cause Analyses

- a. A Root Cause Analysis for a Hydrocarbon Flaring Incident shall consist of a systematic investigation of the incident by identifying and assessing corrective measures that are available to prevent or reduce the likelihood of recurrence of a similar incident (including design, operation and maintenance changes), and developing a program of interim and long-term corrective actions, if any, as are consistent with good engineering practice, to minimize the likelihood of a recurrence of the Root Cause and all contributing causes to the incident, with a schedule for implementation of such measures if not already completed.
- b. The Permittee shall submit a report to the Illinois EPA for each Root Cause Analysis, which report shall include the following information:
 - i. Date, start time and duration of the incident, a description of the incident. To the extent that the incident involved multiple releases within a 24-hour period or within subsequent, contiguous non-overlapping periods, the report shall set forth the starting date, start time and duration of each release.
 - ii. The amount of vent gas flared during the incident and the estimated actual emissions of CO, total hydrocarbons (THC),

VOM* and SO₂ from the incident, with supporting data and calculations.

* For this purpose, the VOM emissions of an incident shall be determined from the difference between the THC emissions and the methane emissions of the incident, using data collected pursuant to Condition 4.7.8-2 for the composition of the flared vent gas.

- iii. The steps taken by the Permittee to reduce the duration or magnitude and emissions of the incident.
 - iv. A detailed analysis that sets forth the root cause and all contributing causes to the incident, to the extent determinable.
 - v. An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of a Hydrocarbon Flaring Incident resulting from the same root cause or contributing causes in the future, which analysis discusses and evaluates the alternatives, if any, that are available, including possible design, operation and maintenance changes, the probable effectiveness of various alternatives, and the cost of the various alternative.
 - vi. If the analysis concludes that corrective actions are required, a description of those actions and, if not already completed, a schedule for their implementation, with planned commencement and completion dates of various actions.
 - vii. If the analysis concludes that corrective action is not needed, an explanation of the basis for that conclusion.
 - viii. If an outside consultant was not retained to assist in the analysis, a discussion why such assistance was not needed, or alternatively, if an outside consultant was retained, a discussion of the particular assistance or expertise that was provided by such consultant.
- c. A report for each such incident and investigation shall be submitted to the Illinois EPA within 45 days of the date of the incident. If the investigation is still underway on this date, the report shall include information for the investigation to that point and a statement of the anticipated date by which a complete follow-up report will be submitted, with explanation why it is not yet practical to submit a complete report for the incident. Thereafter, the Permittee shall submit follow-up report(s) for the incident at least every 45 days until a complete final report is submitted for the incident.
- d. The Root Cause Analysis and accompanying report for a Hydrocarbon Flaring Incident may be combined with the Root Cause Analysis and report for an affected flare for the flaring incident under the NSPS. In such case, other applicable requirements for the

analysis shall also be met. The report shall be clearly marked as a combined report and shall be submitted in accordance with the most stringent provisions for the timing of the report.

4.7.6 Emission Limits

- a. i. The annual emissions from the affected flare for the new Delayed Coker Unit shall not exceed the following limits:

Mode of Operation	Emissions (Tons/Year)				
	CO	NO _x	SO ₂	VOM	PM ₁₀
Pilot & Purge	6.3	1.2	0.1	1.1	–
Other*	7.8	1.4	184.9**	1.3	–
Total	14.1	2.6	185.0	2.4	–

- ii. The emissions of SO₂ from the affected Delayed Coke Unit flare specifically attributable to startup, shutdown and scheduled maintenance, regardless of whether such emissions are due to malfunctions or other causes, shall also not exceed 50.0 tons/year.

- b. The annual emissions from the affected flare for the new Hydrogen Plant shall not exceed the following limits:

Mode of Operation	Emissions (Tons/Year)				
	CO	NO _x	SO ₂	VOM	PM ₁₀
Pilot & Purge	7.7	1.4	0.2	1.3	–
Other*	2.1	3.7	0.4	3.4	–
Total	9.8	5.1	0.6	4.7	–

- c. Compliance with the above annual limits shall be determined from a running total of 12 months of data.

* "Other" includes all emissions from an affected flare other than emissions attributable to combustion of pilot and purge gas by the flare.

** Includes emissions provided by Condition 4.7.6(a)(ii).

- d. This permit is issued based on an increase in emissions from the existing Distilling Flare due to emergency relief flaring from new distillation columns V-3245 and V-3247 and associated equipment as follows:

Emissions (Tons/Year)				
CO	NO _x	SO ₂	VOM	CO ₂ e
1.0	0.2	2.6	2.8	400

4.7.7 Testing Requirements

- a. Upon request by the Illinois EPA, the Permittee shall have testing of an affected flare conducted by a qualified, independent testing service under such operating conditions as may be specified by the Illinois EPA and/or USEPA. The methods

and procedures specified by the NSPS shall be used for testing, including:

- i. USEPA Reference Method 22 shall be used to determine the compliance of flares with the visible emission provisions of Condition 4.7.3(c)(i) (40 CFR 60.18). The observation period is 2 hours and shall be used according to Method 22. [40 CFR 60.18(f)(1)]
 - ii. The net heating value of the gas being combusted in a flare shall be calculated using the equation in 40 CFR 60.18(f)(3).
 - iii. The actual exit velocity of a flare shall be determined by dividing the volumetric flow rate (in units of standard temperature and pressure), as determined by USEPA Reference Methods 2, 2A, 2C, or 2D as appropriate, by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18(f)(4)]
 - iv. If applicable, the maximum permitted velocity, V_{\max} , of a flare shall be determined by the equation in 40 CFR 60.18(f)(5) or (f)(6).
- b.
- i. Upon request by the Illinois EPA, the Permittee shall conduct sampling of process streams in an affected plant to obtain representative samples of the gases that would be sent to the flare for the plant if vent gases were to be flared.
 - ii. The Permittee shall have these samples analyzed for total hydrocarbons (i.e., each of the principal organic compounds in the sample, including methane and ethane) and hydrogen content by volume, total sulfur content (as H_2S) by weight, and lower heating value using appropriate ASTM Test methods or standard analysis methods.
- c. The Permittee shall maintain records of the reports for these tests, which shall include the following, for at least five years from the date that a more recent test is performed:
- i. The date, place and time of sampling or measurements.
 - ii. The date(s) analyses were performed.
 - iii. The company or entity that performed the analyses.
 - iv. The analytical techniques or methods used.
 - v. The results of such analyses.
 - vi. The operating conditions of the unit at the time of sampling or measurement.

- d. The affected flares are subject to 40 CFR 60.104a(j), which provides that the owner or operator shall determine compliance with the concentration requirement in 40 CFR 60.103a(h) according to the test methods and procedures in 40 CFR 60.104a(j)(1)-(4). However, pursuant to 40 CFR 60.104a(j)(4)(iv), if monitoring is conducted at a single point in a common source of fuel gas as allowed under 40 CFR 60.107a(a)(2)(iv), only one performance test is required.

4.7.8-1 Monitoring Requirements

- a. NSPS Ja Monitoring:

- i. H₂S Monitoring.

The affected flares are subject to 40 CFR 60.107a(a)(2), which provides that the owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any flare. However, pursuant to 40 CFR 60.107a(a)(2)(iv), fuel gas combustion devices or flares having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned in the respective fuel gas combustion devices or flares. For the Distilling Flare, the Permittee shall comply with this H₂S monitoring requirement no later than November 11, 2015 pursuant to 40 CFR 60.103a(f).

- ii. Sulfur Monitoring for Assessing Root Cause Analysis Threshold.

The affected flares are subject to 40 CFR 60.107a(e), which provides that the owner or operator shall determine the total reduced sulfur concentration for each gas line directed to an affected flare in accordance with either 40 CFR 60.107a(e)(1), (e)(2) or (e)(3). Different options may be elected for different gas lines. The owner or operator shall comply with the requirements related to either 40 CFR 60.107a(e)(1), (e)(2) or (e)(3) no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

- iii. Flow Monitoring for Flares.

The affected flares are subject to 40 CFR 60.107a(f), which provides that the owner or operator shall install, operate, calibrate and maintain, in accordance with the specifications in 40 CFR 60.107a(f)(1), a Continuous Parameter Monitoring System (CPMS) to measure and record the flow rate of gas discharged to the flare. The owner or operator shall comply with the requirements of this paragraph by no later than November 11, 2015.

iv. Excess Emissions.

The affected flares are subject to 40 CFR 60.107a(i), which provides that, for the purpose of reports required by 40 CFR 60.7(c), periods of excess emissions for the affected flares are defined as specified in 40 CFR 60.107a(i) (1) through (5).

b. In addition to complying with applicable requirements of the NSPS, the continuous monitoring system on each affected new flare for the flow rate of the vent stream that is flared (as addressed by Condition 4.7.8-1(a)(iii)) shall meet the following requirements:

i. The system, which may consist of one or more flow meters, shall meet the following minimum specifications in the header in which the system is installed:

Minimum detectible flow: 0.1 foot/second.

Measured range of flow rates corresponding to velocities from 0.5 to 275 feet/second, with ± 5 percent accuracy.

ii. The system shall take measurements of flow rate at least every minute, record the average values of the flow rate every 15 minutes, hour, and day, and record values of cumulative or "totalized" flow at least every 15 minutes (so as to enable sampling flaring events and hydrocarbon flaring incidents to be readily identified).

iii. When the system is out of service, the Permittee shall monitor relevant operating parameters of the affected plant so that the flow rate of any vent gas to the affected flare may be reliably estimated.

iv. The Permittee shall conduct a verification of the system's accuracy on at least an annual basis. For this purpose, relevant USEPA Reference Methods for measurement of gas flow may be used as alternative to flow verification techniques recommended by the manufacturer of the device.

c. The Permittee shall continuously monitor each affected flare for the presence of a flare pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame in accordance with 40 CFR 60.18(f)(2).

d. The Permittee shall continuously monitor each affected flare with an on/off flow indicating device to identify the occurrence of flow of gases other than normal flow of purge gas to the affected flare from an affected plant.

e. The Permittee shall install, operate and maintain continuous monitoring systems on each affected new flare for the usage of

pilot gas and purge gas by the unit, in scfm. Readings shall be taken at least once every 5 minutes and the average hourly values of the flows shall be recorded each hour and day.

- f. The Permittee shall continuously monitor the liquid level and pressure of the seal drum that serves each affected flare, which monitoring devices shall be operated according to the manufacturer's specifications and requirements.
- g. The Permittee shall keep records for these required monitoring systems of data collected by these systems, which shall be automatically collected by a data logging system, and the following information:
 - i. A file containing a copy of the specifications for each monitoring device and the recommended operating and maintenance procedures for the device as provided by its manufacturer.
 - ii. Operating records for each system that, at a minimum, identify the date and duration of any time when a required monitoring instrument or device for an affected flare was not in operation, with explanation; the performance of manual quality control and quality assurance procedures for the system, and maintenance and repair activities performed for the system.
 - iii. Records identifying deviations from applicable requirements by an affected flare or plant, with explanation, including:
 - A. Records of deviations from Condition 4.7.3(b)(iii) with either: 1) The concentration by volume (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere (SO₂ monitoring); or 2) The concentration (dry basis) of H₂S in fuel gases before being burned in the affected flare (H₂S monitoring).
 - B. Records of the date and duration of any time when there was no pilot flame present at an affected flare.
- h. The Permittee shall develop and maintain written Monitoring Procedures for each affected flare addressing the required monitoring systems and the operational monitoring systems for each unit and affected plant, which shall include the following information. A copy of these procedures shall be submitted to the Illinois EPA for review prior to the initial startup of the affected plant.
 - i. A process flow diagram of the affected flare and the affected plant as related to flaring, identifying major components, such as the header, stack, burner(s), purge gas system, pilot gas system, ignition system, assist system,

and liquid seal for the flare and the vent gas lines and flare gas recovery system for the affected plant.

- ii. Drawing(s), with dimensions, showing the sampling location(s) at which sampling or monitoring is conducted, accompanied by an explanation of the methods used to select these sampling locations for sampling of flare vent gas; flow of flare vent gas, pilot gas and purge gas; on/off flow indicators, HHV analyzer, total sulfur analyzer, operating parameters of the liquid seal, operating parameters of any associated flare gas recovery systems, and operating parameters of the affected plant that could provide credible information on the occurrence or nature of flaring.
- iii. The type, make, and model of each monitoring device used for required monitoring, with a description of manufacturer's specifications for the device, including but not limited to range, precision, accuracy, calibration, and recommended procedures for quality control, quality assurance and maintenance.
- iv. A description of the method and/or data used to establish the actuating and deactuating setting for each on/off flow indicator and the method to be used for verification of these settings.
- v. A description of procedures used to determine the composition and lower heating value of flared vent gas, as required by Condition 4.7.8-2.
- vi. A description of the data collection and recording device(s) used to store data collected by required monitoring systems.

4.7.8-2 Sampling And Analysis of Flared Vent Gas

- a. The Permittee shall monitor the composition of vent gas to each affected new flare for hydrocarbons and sulfur content by one of the following options. The resulting data for composition of vent gas shall be used to determine the lower heating value of the vent gas, with records kept of the lower heating value of the vent gas for each period when vent gas is flared (flaring event or incident), with supporting documentation and calculations.
- b. Option 1: Sampling and Analysis

The Permittee shall sample and analyze vent gas samples from a location at which samples are representative of the vent gas that is being flared by the affected new flare, as follows:

- i. Samples shall be taken if the flow rate of the vent gas flared in any consecutive 15 minutes interval is 330 scf per minute (scfm) or more, with a sample taken within the

next 15 minutes. Thereafter, the sampling frequency shall be at least one sample every three hours until the flow rate of the vent gas is continuously less than 330 scfm in any 15 minute interval.

ii. Collected samples of vent gas shall be analyzed in a timely manner using the following methods or other equivalent method approved by the Illinois EPA:

A. Hydrocarbon contents (i.e., each of the principal organic compounds in the sample, including methane and ethane) - ASTM Method D1945-96, ASTM Method UOP 539-97, or USEPA Method 18.

B. H₂S content - ASTM Method D1945-96 or ASTM Method UOP 539-97.

iii. Notwithstanding the above, sampling is not required for any flare event that:

A. Is a result of a catastrophic event including a major fire or an explosion at the facility such that collecting a sample is infeasible or constitutes a safety hazard, or

B. Constitutes a safety hazard to the sampling personnel at the established sampling location(s) during the entire flare event, provided that a sample is collected at an alternative location if a sample that is representative of the flared vent gas can be safely collected at an alternative location.

iv. Records shall be kept for this activity that, at minimum, include records of the date and time each sample is collected and records for the results of the subsequent analysis of each sample, with documentation for the analytical methodology.

c. Option 2: Continuous Analyzer Not Using Gas Chromatography

As an alternative to Option 1, the Permittee may install, operate and maintain a continuous monitoring system for total hydrocarbons (THC), methane and either H₂S or TRS for the affected new flare, as follows:

i. The THC analyzer shall have a full-scale range of 100 percent.

ii. Each analyzer shall be maintained to be accurate to within 20 percent when compared to any field accuracy tests or to within 5 percent of full scale.

iii. The composition of the vent gas shall be determined by the following methods or later version of these methods, unless

the application of one the methods to the vent gas stream is determined to be technically infeasible, in which case, an alternative method approved by the Illinois EPA that is no less stringent than the infeasible method shall be used:

A. THC and methane content: USEPA Method 25A or 25B.

B. TRS content: ASTM Method D4468-85.

C. H₂S content: ASTM Method D4084-94.

iv. Recordkeeping and reporting shall be conducted for this monitoring activity as required for continuous emissions monitoring systems, including recordkeeping in accordance with Condition 4.7.8-1(g).

v. A supplement to the Monitoring Procedures pursuant to Condition 4.7.8-1(h), which addresses this monitoring activity, shall be submitted to the Illinois EPA at least 60 days before relying on this Option to comply with Condition 4.7.8-2(a). If the reliance on this Option is terminated, the Illinois EPA shall be notified within 15 days.

d. Option 3: Continuous Analyzer Using Gas Chromatography

As an alternative to Option 1, the Permittee may install, operate and maintain a continuous monitoring system using gas chromatography for THC, methane and H₂S for the affected new flare as follows:

i. The gas chromatography system shall be maintained to be accurate to within 5 percent of full scale.

ii. The minimum sampling frequency shall be one sample every 30 minutes.

iii. Composition of the vent gas shall be determined by ASTM Method D1945-96 or ASTM Method UOP 539-97 (or a later version of these methods) or other equivalent method approved by the Illinois EPA.

iv. Recordkeeping and reporting shall be conducted for this monitoring activity in accordance with Condition 4.7.8-1(g).

4.7.8-3 Visual Imaging and Observation Requirements

- a. i. The Permittee shall install, operate and maintain visual imaging equipment on each affected new flare to monitor for the occurrence of flaring and the presence of visible emissions. This equipment shall record a real-time, digital, color image of the burner area of the affected new flare, including the flame when vent gases are being

flared. The recorded image shall be of sufficient size, contrast, and resolution so that the presence of a flame, the occurrence of flaring, and any visible emissions from flaring are readily apparent in the overall image. Images shall be recorded at a rate of no less than one image per minute and shall include an embedded date and time stamp.

- ii. For each affected new flare, the Permittee shall archive the digital images for each 24-hour period in a standard electronic format and retain the archived images at the source for at least 90 days.
 - iii. The Permittee shall provide the Illinois EPA and USEPA with access to the archived images at the source and, upon request by the Illinois EPA or USEPA, provide a copy of the archived images for particular day(s) or periods to the Illinois EPA, either in electronic format or as printed images as requested by the Illinois EPA or USEPA, as applicable.
- b. During periods when the continuous visual imaging equipment is not operational, the Permittee shall conduct observation for visible emissions from an affected new flare when vented gases are flared for more than 15 minutes, as follows:
- i. Observations shall not be required during periods when valid observations of visible emissions using USEPA Method 22 are not possible, during periods when all personnel capable of conducting such observations are engaged in other essential tasks related to the flaring event, and during periods when such observations would pose a significant safety hazard to an observer due to the unusual circumstances of the event.
 - ii. Observations shall be conducted using Method 22.
 - iii. Observations shall begin within 30 minutes after the start of the flaring event and continue at least every 30 minutes thereafter.
 - iv. The duration of each period of observation shall be at least 6 minutes, after which time observation may be ended even if visible emissions are observed.
 - v. The Permittee shall keep a log or other records for this activity that includes information as specified by Method 22 for each period of observations and information explaining why observations, if any, were not performed for the flaring event.

4.7.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items:

- a. For each affected flare, the Permittee shall comply with the applicable recordkeeping requirements of the NSPS, 40 CFR 60.7 and 60.108a, including maintaining the following records:
 - i. A copy of the Flare Management Plan. [40 CFR 60.108a(c)(1)]
 - ii. Records of discharges greater than 500 lb SO₂ in any 24-hour period from any affected flare and discharges to an affected flare in excess of 500,000 scf above baseline in any 24-hour period as required by 40 CFR 60.103a(c). The information in 40 CFR 60.108a(c)(6)(i)-(xi) shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds. [40 CFR 60.108a(c)(6)]
 - iii. If the owner or operator elects to comply with 40 CFR 60.107a(e)(2), records of the H₂S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H₂S ratios, the calculated 10-day average total sulfur-to-H₂S ratios and the 95-percent confidence intervals for each 10-day average total sulfur-to-H₂S ratio. [40 CFR 60.108a(c)(7)]
- b. The Permittee shall maintain a file containing the following information:
 - i. An engineering analysis for the Flare Gas Recovery System for the Delayed Coker Unit addressing compliance with Condition 4.7.5-1(a)(iii), including a description of the recovery system, the capacity of each compressor, and information on the generation of process gas during the different modes of operation of the Delayed Coker Unit.
 - ii. Information for the automatic igniter device on each affected flare, including the make and model of device, a description of device, and a summary of the operating procedures for the device.
- c. The Permittee shall maintain a file that contains the following information related to the methodology that the Permittee will follow for calculating emissions from each affected flare, including:
 - i. A description of the procedures for calculating emissions attributable to combustion of pilot gas, purge gas, process upset gas, and process gas.
 - ii. A description of the procedures for calculating VOM emissions for purposes of determining whether a Hydrocarbon Flaring Incident has occurred.
 - iii. A description of the procedures expected to be used for determining flows and composition of different streams to the flare as related to operational monitoring, if required

continuous monitoring system(s) are not in service during a flaring event.

- iv. A description of the procedures for determining the hydrogen content, of different streams to the affected flare for the Hydrogen Plant unit as related to operational monitoring, if sampling and analysis is not conducted for a stream, with the typical values of hydrogen content that will be used for different streams, with supporting documentation.
- d. The Permittee shall maintain records of the following items for each exceedance of a standard, requirement or limit in Condition 4.7.3, 4.7.5-1, 4.7.5-2, 4.7.5-3, or 4.7.6, which shall include:
 - i. Identification of the applicable requirement(s) that may have been exceeded.
 - ii. Duration of the possible exceedance.
 - iii. An estimate of the amount of emissions in excess of the applicable requirement(s).
 - iv. A description of the cause of the possible exceedance.
 - v. When compliance was reestablished.
- e. The Permittee shall maintain records for operation and emissions of each affected flare, including:
 - i. Operation and emissions associated with the pilot flame and purge gas streams.
 - ii. Detailed information for each flaring event, i.e., period when vent gas from the associated affected plant was flared, including, date, time, duration, description of the event, total volume of gas flared*, whether any vent gas was recovered for fuel with estimated amount*, total hydrocarbon (THC), VOM and sulfur content of the flared vent gas*, estimated actual emissions of CO, THC, VOM and SO₂*, detailed explanation of reason for flaring, any measures taken to prevent similar events, and other relevant information related to the flaring event.
 - * Accompanied by supporting calculations.
 - iii. Records of VOM, NO_x, SO₂, and CO emissions from each affected flare (tons/month and tons/year), with supporting calculations.
 - iv. Records of the SO₂ emissions (tons/month and tons/year) of the affected Delayed Coking Unit Flare specifically attributable to startup, shutdown and scheduled maintenance, accompanied by list of each period of startup,

each period of shutdown, and each period of scheduled maintenance for the unit, in chronological order with date, duration, type and the SO₂ emissions for the period.

- f. The Permittee shall maintain records, pursuant to 35 IAC 201.263, of continued operation of equipment venting to the affected Delayed Coker Unit Flare during malfunctions or breakdown, which as a minimum, shall include:
 - i. Date and duration of malfunction or breakdown.
 - ii. A detailed explanation of the malfunction or breakdown.
 - iii. An explanation why the equipment venting to this flare continued to operate.
 - iv. The measures used to reduce the quantity of emissions and the duration of the event.
 - v. The steps taken to prevent similar malfunctions or breakdowns or reduce their frequency and severity.
 - vi. The amount of release above typical emissions during malfunction/breakdown.

4.7.10 Reporting Requirements

- a. The affected flares are subject to 40 CFR 60.108a(d), which provides that each owner or operator shall submit an excess emissions report for all periods of excess emissions according to the requirements of 40 CFR 60.7(c) except that the report shall contain the information specified in 40 CFR 60.108a(d)(1) through (7).
- b. The Permittee shall notify the Illinois EPA of deviations of an affected flare with the permit requirements of this section (Section 4.7), as follows. These reports shall include a description of the deviation, the probable cause of the deviation, any corrective actions and preventative measures taken, and any other information that is specified for the particular type of deviation.
 - i. Exceedance of an emission limit in Conditions 4.7.3(d), 4.7.5-1(b), or 4.7.6, shall be reported within 30 days and these reports shall also include:
 - A. Identification of the limit that may have been exceeded.
 - B. Duration of the possible exceedance.
 - C. An estimate of the amount of emissions in excess of the applicable limit, with supporting calculations.

- D. A detailed description of the cause of the possible exceedance.
 - E. When compliance was reestablished.
 - ii. Deviations from the requirements of the NSPS shall be reported in accordance with applicable reporting requirements of the NSPS.
 - iii. Other deviations shall be reported with the periodic compliance report required for the affected flares by Condition 4.7.10(d).
- c. Reporting of Malfunctions and Breakdowns

The Permittee shall provide the following notification and reports to the Illinois EPA, Air Compliance Unit and Regional Field Office, pursuant to 35 IAC 201.263, concerning continued operation of equipment venting to the affected Delayed Coker Unit Flare during malfunction or breakdown with SO₂ emissions that violated 35 IAC 214.301:

 - i.
 - A. The Permittee shall notify the Illinois EPA's regional office by telephone as soon as possible during normal working hours, but no later than 24 hours, upon the occurrence of noncompliance due to malfunction or breakdown.
 - B. Upon achievement of compliance, the Permittee shall give a written follow-up notice within 15 days to the Illinois EPA, Air Compliance Unit and Regional Field Office, providing a detailed explanation of the event, an explanation why continued operation of equipment venting to this flare was necessary, the length of time during which operation continued under such conditions, the measures taken by the Permittee to minimize and correct deficiencies with chronology, and when the repairs were completed or when the particular equipment venting to this flare was taken out of service.
 - C. If compliance is not achieved within 48 hours of the occurrence, the Permittee shall submit interim status reports to the Illinois EPA, Air Compliance Unit and Regional Field Office, on a daily basis, until compliance is achieved. These interim reports shall provide a brief explanation of the nature of the malfunction or breakdown, corrective actions accomplished to date, actions anticipated to occur with schedule, and the expected date on which repairs will be complete or the particular equipment venting to this flare will be taken out of service.

- ii. The Permittee shall submit periodic malfunction and breakdown reports to the Illinois EPA, that include the following information for malfunctions and breakdowns of equipment venting to this flare during the reporting period:
 - A. A listing of malfunctions and breakdowns, in chronological order, that includes:
 - 1. The date, time, and duration of each incident.
 - 2. The identity of the equipment involved in the incident.
 - B. Dates of the notices and reports pursuant to Conditions 4.7.10(c)(i).
 - C. Any supplemental information the Permittee wishes to provide to the notices and reports pursuant to Conditions 4.7.10(c)(i).
 - D. If there have been no such incidents during the reporting period, this shall be stated in the report.
- d. The Permittee shall submit periodic compliance reports to the Illinois EPA for each affected flare, which reports shall be submitted along with other periodic compliance reports required by the source's CAAPP permit. These reports shall include the following information:
 - i. A listing of each flaring event during the reporting period, i.e., each period when vent gas was flared, with date and duration, a description of the event, including cause(s), whether an event-specific Root Cause Analysis was performed for the event pursuant to Condition 4.7.5-1(a)(vi), and the estimated actual emissions of CO, TOC, VOM and SO₂.
 - ii. The information required by Condition 4.7.10(b)(iii) for deviations during the reporting period, including periods of downtime of a required monitoring system for reasons other than routine calibration and maintenance, if more than 2.5 percent of the operating time of the affected plant during the reporting period.
 - iii. The further information required by Condition 4.7.10(c)(ii) for malfunctions and breakdown that were accompanied with excess emissions of SO₂.
 - iv. Provide an analysis of the amount of vented gas that was recovered compared to the amount of vented gas that was flared.

- v. Summarize actions or measures implemented during the previous year to reduce flaring pursuant to the Root Cause Analyses required by Condition 4.7.5-1(a)(vi) and 40 CFR 60.103a(b), and the observed effect of these actions, and the actions or measures planned for implementation during the current year to reduce flaring pursuant to Root Cause Analyses, and the expected effect of these actions.
- vi. Summarize other actions or measures implemented during the previous year to reduce flaring, not related to required Root Cause Analyses, and the reason for and observed effect of these actions, and other actions or measures planned for implementation during the current year to reduce flaring, and the reason for and expected effect of these actions.
- vii. Include a listing of changes, if any, made to the Flare Minimization Plan, as provided for by Conditions 4.7.5-2(b)(ii) and (iii), with brief description.
- viii. Include a listing of significant changes, if any, made to the Monitoring Procedures required by Condition 4.7.8-1(h), with brief description.
- ix. Provide confirmation that the required annual verification of the accuracy of the flow monitoring system was conducted, with a summary of results.
- x. Provide confirmation that the annual survey of pressure relief devices, if required, was conducted, with a summary of results.

4.8 Sulfur Recovery Units (SRU)

4.8.1 Description

As part of the CORE project, two additional sulfur recovery units (SRU-E and SRU-F) will be constructed for the purpose of removing sulfur from refinery fuel gas prior to its combustion in the heaters and boilers at the refinery. Each SRU will have a separate Amine Regeneration Unit, Claus Train, Tail Gas Treating Unit (TGU) and Thermal Oxidizer.

Also constructed will be additional sulfur storage and loading facilities. The vapors recovered from the storage and loading facilities will be routed to the Claus Trains or TGU to ensure that captured residual H_2S/SO_2 is controlled.

4.8.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
SRU-E	Sulfur Recovery Unit "E"	TGU (TGU-E), Thermal Oxidizer
SRU-F	Sulfur Recovery Unit "F"	TGU (TGU-F), Thermal Oxidizer

4.8.3 Applicable Provisions and Emission Standards

- a. An "affected unit" for the purpose of these unit-specific conditions, is a sulfur recovery unit described in Conditions 4.8.1 and 4.8.2.

b. NSPS Provisions

The affected units are subject to the NSPS for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60 Subpart Ja and applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A. In particular:

The affected units are subject to 40 CFR 60.102a(f)(1)(i), which provides that the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 250 ppmv limit for each process train or release point or comply with a flow rate weighted average of 250 ppmv for all release points from the sulfur recovery plant.

c. NESHAP Provisions

The affected units are subject to the NESHAP for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, 40 CFR 63 Subpart UUU and applicable requirements of the General Provisions of the NESHAP, 40 CFR 63 Subpart A.

- i. The Permittee shall comply with the applicable requirements for HAP emissions from sulfur recovery units in 40 CFR 63.1568. In particular, the Permittee shall comply with the emission limitations for NSPS units, pursuant to 40 CFR 63.1568(a)(1).
 - ii. The Permittee shall comply with all applicable requirements of 40 CFR Part 63, Subpart UUU for the affected units.
- d. State Provisions

The affected units are subject to 35 IAC 214.382(b), which provides that no person shall cause or allow the emission of more than 1,000 ppm of sulfur dioxide into the atmosphere from any new process emission source in the St. Louis (Illinois) major metropolitan area designed to remove sulfur compounds from the flue gases of petroleum and petrochemical processes. Compliance with this standard shall be demonstrated on a three-hour block average basis.

4.8.4 Nonapplicability of Regulations of Concern

Nonapplicability of regulations of concern are not set for the affected unit.

4.8.5 Control Requirements and Work Practices

- a.
 - i. BACT/LAER Technology

The thermal oxidizer on each affected unit shall be maintained and operated with good combustion practice to reduce emissions of CO and VOM.
 - ii. BACT Emission Limit

Emissions of CO from each affected unit shall not exceed 0.082 lb/mmBtu, HHV, 30-day rolling average.
 - iii. LAER Emission Limit

Emissions of VOM from each affected unit shall not exceed 0.005 lb/mmBtu, HHV, 30-day rolling average.
- Note: Condition 4.8.5(a)(i) and (ii) represent the application of the Best Available Control Technology. Condition 4.8.5(a)(i) and (iii) represent the application of the Lowest Achievable Emission Rate.
- b. The Permittee shall operate the affected units and associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions set forth in 40 CFR 60.11(d).

- c. The Permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in 40 CFR 63.1574(f) and operate at all times according to the procedures in the plan. [40 CFR 63.1568(a)(3)]
- d. The Permittee shall comply with the applicable general requirements for affected units identified in 40 CFR 63.1570.
- e. The affected units are subject to 40 CFR 60.103a(c), which provides that each owner or operator shall conduct a root cause analysis and a corrective action analysis as follows:

For each affected unit, each time the SO₂ emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO₂ or reduced sulfur concentration was equal to the applicable emissions limit in 40 CFR 60.102a(f)(1) during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

- f. The affected units are subject to 40 CFR 60.103a(e), which provides that the owner or operator shall implement the corrective action(s) identified in the Corrective Action Analysis in accordance with the applicable requirements in 40 CFR 60.103a(e)(1) through (3).

4.8.6 Emission Limits

- a. Annual emissions from the affected units shall not exceed the following limits:

Equipment	NO _x	CO	VOM	SO ₂	PM/PM ₁₀
	Tons/Yr	Tons/Yr	Tons/Yr	Tons/Yr	Tons/Yr
SRU-E	18.4	21.6	1.4	218.7	2.0
SRU-F	18.4	21.6	1.4	218.7	2.0

- b. Compliance with annual limits shall be determined from a running total of 12 months of data.

4.8.7 Testing Requirements

- a. The owner or operator shall conduct a performance test for each affected unit to demonstrate initial compliance with each applicable emissions limit in 40 CFR 60.102a according to the requirements of 40 CFR 60.8. The notification requirements of 40 CFR 60.8(d) apply to the initial performance test and to subsequent performance tests required by 40 CFR 60.104a(b) (or as required by the USEPA), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments. [40 CFR 60.104a(a)]
- b. Compliance with the SO₂ emissions limit for the affected units in 40 CFR 60.102a(f)(1)(i) shall be determined using the methods and procedures in 40 CFR 60.104a(h)(1)-(5). [40 CFR 60.104a(h)]

4.8.8 Monitoring Requirements

a. NSPS Ja Monitoring Requirements

The affected units are subject to 40 CFR 60.106a(a)(1), which provides that the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

- i. The span values for this monitor are two times the applicable SO₂ emission limit and between 10 and 25 percent O₂, inclusive.
- ii. The owner or operator shall install, operate, and maintain each SO₂ CEMS according to Performance Specification 2 of 40 CFR 60 Appendix B.
- iii. The owner or operator shall conduct performance evaluations of each SO₂ monitor according to the requirements in 40 CFR 60.13(c) and Performance Specification 2 of 40 CFR 60 Appendix B. The owner or operator shall use Methods 6 or 6C of 40 CFR 60 Appendix A-4 and Method 3 or 3A of 40 CFR 60 Appendix A-2 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR 60.17) is an acceptable alternative to EPA Method 6.

b. NESHAP Monitoring Requirements

The Permittee shall install, operate, and maintain a continuous monitoring system to measure and record the hourly average concentration of SO₂ (dry basis) at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air. [40 CFR 63.1568(b)(1)]

4.8.9 Recordkeeping Requirements

- a. The Permittee shall maintain records of sulfur production (long tons/day, long tons/month, and long tons/year).
- b. The Permittee shall maintain records of emissions of NO_x, CO, VOM, SO₂, and PM/PM₁₀ (tons/month and tons/year).
- c. The affected units are subject to 40 CFR 60.108a(a), which provides that the owner or operator shall comply with the recordkeeping requirements in 40 CFR 60.7 and other requirements as specified in 40 CFR 60.108a.

4.8.10 Reporting Requirements

a. Reporting of Deviations

The Permittee shall notify the Illinois EPA of deviations from the requirements of this section (Section 4.8) within 30 days of such occurrence. Reports shall describe the deviation, the probable cause of such deviation, the corrective actions taken, and any preventative measures taken. As the operation of affected units is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such regulations.

- b.
 - i. The affected units are subject to 40 CFR 60.108a(a), which provides that the owner or operator shall comply with the notification and reporting requirements in 40 CFR 60.7 and other requirements as specified in 40 CFR 60.108a.
 - ii. Excess emissions. For the purpose of reports required by 40 CFR 60.7(c), periods of excess emissions for the affected units are defined as specified in 40 CFR 60.106a(b)(1)-(3). [40 CFR 60.106a(b)]
- c. The Permittee shall submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.1574. [40 CFR 63.1568(b)(7)]

4.9 Miscellaneous PM Emission Units

4.9.1 Description

The storage and handling of coke produced at the new delayed coker unit will generate fugitive particulate emissions. These coke handling operations include several new conveyor and crane transfer points, a new crusher, front-end loader (FEL) traffic, and loading of coke haul trucks.

4.9.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Coke Handling	Coke Handling	Operating Program

4.9.3 Applicability Provisions

The "affected unit" for the purpose of these unit-specific conditions, is the unit described in Conditions 4.9.1 and 4.9.2.

4.9.4 Nonapplicability of Regulations of Concern

Nonapplicability of regulations of concern are not set for the affected unit.

4.9.5 Operating Program for Control of Fugitive Particulate Emissions

- a. The Permittee shall carry out control of fugitive particulate emissions from affected units in accordance with a written operating program describing the measures being implemented to control emissions from these units, which program shall be kept current.
- b. The Permittee shall submit a copy of significant amendments to the program by the Permittee within 30 days of the date that the amendment is made.
- c. A revised operating program shall be submitted to the Illinois EPA for review within 90 days of a request from the Illinois EPA for revision to address observed deficiencies in control of fugitive particulate emissions.

4.9.6 Operational and Emission Limits

- a. The maximum coke processed shall not exceed 5,400 dry tons/day, 12-month rolling average.
- b. Emissions from the affected unit shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data.

Pollutant	Limits	
	Tons/Month	Tons/Year
PM	7.0	69.7
PM ₁₀	2.4	23.9

4.9.7 Testing Requirements

Testing requirements are not set for the affected unit.

4.9.8 Monitoring Requirements

Monitoring requirements are not set for the affected unit.

4.9.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items:

- a. Coke processed (dry tons/day).
- b. PM and PM₁₀ emissions (tons/month and tons/year) from the affected units with supporting calculations and documentation.

4.9.10 Reporting Requirements

The Permittee shall notify the Illinois EPA of deviations from the requirements of this section (Section 4.9), within 30 days of such occurrence. Reports shall describe the deviation, the probable cause of such deviation, the corrective actions taken, and any preventative measures taken.

4.10 Wastewater Treatment Plant

4.10.1 Description

New clarifiers will be added as well as changes made to Pond 1 and Pond 2 to: (i) accommodate an increase in wastewater flow including solids and organic loading due to increased refining operations, and (ii) treat the wastewater from the new Wet Gas Scrubbers (WGS) on the FCC Units.

In addition, new process sumps and sewers will be installed to support the new and expanded process units.

Note: Emissions from the debottlenecked primary treatment system that are controlled by flares and from debottlenecked uncontrolled wastewater treatment units are addressed in Section 3.4.3 (Debottlenecked Wastewater Treatment Plant Operations).

4.10.2 List of Emission Units and Air Pollution Control Equipment

Emission Units	Description
Scrubber Solids Clarifiers	New scrubber solids clarifiers (primary).
Secondary Treatment System	New final clarifier (secondary).
Biological Treatment System	Reconfiguring Pond 1 to activated sludge service, modifications to Pond 2 with a denitrification zone added to the back of the pond.
IDS	New process sewers and sumps commonly referred to as Individual Drain Systems.

4.10.3 Applicable Provisions and Emission Standards

- a.
 - i. The “affected scrubber solids clarifiers” for the purpose of these unit-specific conditions, are the new scrubber solids clarifiers (primary) described in Conditions 4.10.1 and 4.10.2.
 - ii. The “affected secondary treatment system” for the purpose of these unit-specific conditions, is the new final clarifier (secondary) described in Conditions 4.10.1 and 4.10.2.
 - iii. The “affected biological treatment system” for the purpose of these unit-specific conditions, is the reconfigured Pond 1, modified Pond 2 described in Conditions 4.10.1 and 4.10.2.
 - iv. The “affected IDS” for the purpose of these unit-specific conditions, are the new process sewers and sumps described in Conditions 4.10.1 and 4.10.2.
 - v. Collectively, the affected scrubber solids clarifiers, affected secondary treatment system, affected biological

treatment system, and affected IDS are referred to as "affected units."

- b. The refinery, including the affected scrubber solids clarifiers, affected secondary treatment system and the affected biological treatment system, is subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Benzene Waste Operations, 40 CFR 61 Subpart FF and applicable requirements of the General Provisions of the NESHAP, 40 CFR 61, Subpart A.
 - i. The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of 40 CFR 61.342(c)(1); and [40 CFR 61.342(e)(1)]
 - ii. The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following: [40 CFR 61.342(e)(2)]
 - A. The benzene quantity for the wastes described in 40 CFR 61.342(e)(2) must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in 40 CFR 61.355(k). Wastes as described in 40 CFR 61.342(e)(2) that are transferred offsite shall be included in the determination of benzene quantity as provided in 40 CFR 61.355(k). The provisions of 40 CFR 61.342(f) shall not apply to any owner or operator who elects to comply with the provisions of 40 CFR 61.342(e). [40 CFR 61.342(e)(2)(i)]
 - B. The determination of benzene quantity for each waste stream defined in 40 CFR 61.342(e)(2) shall be made in accordance with 40 CFR 61.355(k). [40 CFR 61.342(e)(2)(ii)]
- c. The affected IDS are subject to the NSPS for VOC Emissions From Petroleum Refinery Wastewater Systems, 40 CFR 60 Subpart QQQ and applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A. In particular, the Permittee shall comply with the applicable standards for IDS at 40 CFR 60.692-2, inspection requirements at 40 CFR 60.696, recordkeeping requirements at 40 CFR 60.697, and reporting requirements at 40 CFR 60.698.

4.10.4 Nonapplicability of Regulations of Concern

Nonapplicability of regulations of concern are not set for the affected units.

4.10.5 Control Requirements and Work Practices

LAER Technology. This condition represents the application of the Lowest Achievable Emission Rate.

- a. Specific provisions setting LAER for the scrubber solids clarifiers, denitrification zone, and final clarifier are not being established due to the small amount of VOM being emitted from these operations.
- b. The affected units shall be operated in accordance with good air pollution control practice to minimize emissions of VOM.

4.10.6 Emission Limits

VOM emissions from the new scrubber solids clarifiers, denitrification zone, and final clarifier shall not exceed 1.0 tons/year, in total.

4.10.7 Testing Requirements

The Permittee shall comply with the applicable test methods, procedures, and compliance provisions of 40 CFR 61.355.

4.10.8 Monitoring Requirements

The Permittee shall comply with the applicable monitoring of operations of 40 CFR 61.354.

4.10.9 Recordkeeping Requirements

- a. The Permittee shall comply with the applicable recordkeeping requirements of 40 CFR 61.356.
- b. The Permittee shall maintain a file that contains documentation for the potential emissions of VOM from the new scrubber solids clarifiers, denitrification zone, and final clarifier, with supporting documentation.

4.10.10 Reporting Requirements

- a. The Permittee shall comply with the reporting requirements of 40 CFR 61.357.

b. Reporting of Deviations

The Permittee shall notify the Illinois EPA of deviations from the requirements of an affected unit with the permit requirements of this section (Section 4.10), as follows. Reports shall describe the deviation, the probable cause of such deviation, the corrective actions taken, and any preventative measures taken. As the operation of affected unit is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such regulations.

- i. Within 30 days of exceedance of the limit in Condition 4.10.6.

4.11 Roadways and Other Open Areas

4.11.1 Description

The affected units for the purpose of these unit-specific conditions are roadways, parking areas, and other open areas which are affected by the new CORE process units, and which may be sources of fugitive particulate matter due to vehicle traffic or windblown dust. These emissions are controlled by paving and implementation of work practices to prevent the generation and emissions of particulate matter.

4.11.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Roadways and Other Open Areas	Paved and unpaved roads; parking lots; other open areas.	Fugitive Particulate Matter Operating Program

4.11.3 Applicable Provisions and Regulations

- a. "Affected units" for the purpose of these unit-specific conditions, are the units described in Conditions 4.11.1 and 4.11.2.
- b.
 - i. The affected units are subject to 35 IAC 212.301, which provides that no person shall cause or allow the emission of fugitive particulate matter from any process, including any material handling or storage activity, that is visible by an observer looking generally toward the zenith at a point beyond the property line of the source.
 - ii. Notwithstanding the above, pursuant to 35 IAC 212.314, the above limit shall not apply and spraying to control fugitive dust pursuant to 35 IAC 212.304 through 212.310 and 212.312 shall not be required when the wind speed is greater than 25 mile/hour (40.2 km/hour), as determined in accordance with the provisions of 35 IAC 212.314.
- c. The affected units are subject to 35 IAC 212.306, which provides that all normal traffic pattern access areas surrounding storage piles specified in 35 IAC 212.304 and all normal traffic pattern roads and parking facilities shall be paved or treated with water, oils or chemical dust suppressants. All paved areas shall be cleaned on a regular basis. All areas treated with water, oils or chemical dust suppressants shall have the treatment applied on a regular basis, as needed, in accordance with the operating program required by 35 IAC 212.309, 212.310 and 212.312.

4.11.4 Nonapplicability of Regulations of Concern

Nonapplicability of regulations of concern are not set for the affected units.

4.11.5 Control Requirements and Work Practices

- a. Good air pollution control practices shall be implemented to minimize and significantly reduce nuisance dust from affected units associated with the CORE Project. After construction of the CORE project is complete, these practices shall provide for pavement on all regularly traveled roads and treatment (flushing, vacuuming, dust suppressant application, etc.) of roadways and areas that are routinely subject to vehicle traffic for very effective control of dust (nominal 90 percent control).
- b. For this purpose, roads that serve any new permanent office building, new employee parking areas or are used on a daily basis by operating and maintenance personnel for the refinery in the course of their typical duties, roads that experience heavy use during regularly occurring maintenance of the refinery during the course of a year, shall all be considered to be subject to regular travel and are required to be paved. Regularly traveled roads shall be considered to be subject to routine vehicle traffic except as they are used primarily for periodic maintenance and are currently inactive or as traffic has been temporarily blocked off. Other roads shall be considered to be routinely traveled if activities are occurring such that they are experiencing significant vehicle traffic.
- c. The handling of material collected from any affected unit associated with the refinery by sweeping or vacuuming trucks shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods to control PM emissions.

4.11.6 Emission Limits

- a. The emissions of fugitive dust from roadways and parking lots shall not exceed 59.3 tons/year of PM and 11.6 tons/year of PM₁₀.
- b. Compliance with annual limits shall be determined from a running total of 12 months of data.

4.11.7 Testing Requirements

- a. Opacity Measurement Requirements
 - i. The Permittee shall conduct performance observations, which include a series of observations of the opacity of fugitive emissions from the affected units as follows to determine the range of opacity from affected units and the change in opacity as related to the amount and nature of vehicle traffic and implementation of the operating program. For performance observations, the Permittee shall submit test plans, test notifications and test reports, as specified by Condition 3.6.2.

- A. Performance observations shall first be completed no later than 30 days after initial startup of the CORE Project, in conjunction with the measurements of silt loading on the affected units required by Condition 4.11.7(b).
 - B. Performance observations shall be repeated within 30 days in the event of changes involving affected units that would act to increase opacity (so that observations that are representative of the current circumstances of the affected units have not been conducted), including changes in the amount or type of traffic on affected units, changes in the standard operating practices for affected units, such as application of salt or traction material during cold weather, and changes in the operating program for affected units.
 - ii. Compliance observations shall be conducted for affected units on at least a quarterly basis to verify opacity levels and confirm the effectiveness of the operating program in controlling emissions.
 - iii. Upon written request by the Illinois EPA, the Permittee shall conduct performance or compliance observations, as specified in the request. Unless another date is agreed to by the Illinois EPA, performance observations shall be completed within 30 days and compliance observations shall be completed within 5 days of the Illinois EPA's request.
- b. Silt Loading Measurements
- i. The Permittee shall conduct measurements of the silt loading on various affected roadway segments and parking areas, as follows:
 - A. Sampling and analysis of the silt loading shall be conducted using the "Procedures for Sampling Surface/Bulk Dust Loading," Appendix C.1 in Compilation of Air Pollutant Emission Factors, USEPA, AP-42. A series of samples shall be taken to determine the average silt loading and address the change in silt loadings as related to the amount and nature of vehicle traffic and implementation of the operating program.
 - ii. Measurements shall be performed by the following dates:
 - A. Measurements shall first be completed no later than 30 days after the date that initial startup of the CORE project is completed.
 - B. Measurements shall be repeated within 30 days in the event of changes involving affected units that would

act to increase silt loading (so that data that is representative of the current circumstances of the affected units has not been collected), including changes in the amount or type of traffic on affected units, changes in the standard operating practices for affected units, such as application of salt or traction material during cold weather, and changes in the operating program for affected units.

C. Upon written request by the Illinois EPA, the Permittee shall conduct measurements, as specified in the request, which shall be completed within 75 days of the Illinois EPA's request.

iii. The Permittee shall submit test plans, test notifications and test reports for these measurements as specified by Condition 3.6.2, provided, however, that once a test plan has been accepted by the Illinois EPA, a new test plan need not be submitted if the accepted plan will be followed or a new test plan is requested by the Illinois EPA.

4.11.8 Monitoring Requirements

Monitoring requirements are not set for the affected units.

4.11.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected units:

- a. The Permittee shall maintain records for each period of time when it relies upon the exemption provided by 35 IAC 212.314 to not comply with 35 IAC 212.301 or implement measures otherwise required by 35 IAC 212.304 through 212.310, or 212.312, with supporting documentation for the determination of wind speed.
- b. The Permittee shall maintain records documenting implementation of the operating program required by 35 IAC 212.309, 212.310 and 212.312, including:
 - i. Records for each treatment of an affected unit or units:
 - A. The identity of the affected unit(s), the date and time, and the identification of the truck(s) or treatment equipment used;
 - B. For application of dust suppressant by truck: target application rate or truck speed during application, total quantity of water or chemical used and, for application of a chemical or chemical solution, the identity of the chemical and concentration, if applicable;

- C. For sweeping or cleaning: Identity of equipment used and identification of any deficiencies in the condition of equipment; and
 - D. For other type of treatment: A description of the action that was taken.
- ii. Records for each incident when control measures were not implemented and each incident when additional control measures were implemented due to particular activities, including description, date, a statement of explanation, and expected duration of such circumstances.
- c.
 - i. The Permittee shall keep records for the silt measurements conducted for affected units pursuant to Condition 4.11.7(b), including records for the sampling and analysis activities and results.
 - ii. The Permittee shall maintain records for all opacity measurements made in accordance with USEPA Method 9 for the affected units that the Permittee conducts or that are conducted on its behest by individuals who are qualified to make such observations. For each occasion on which such measurements are made, these records shall include the formal report for the measurements if conducted pursuant to Condition 4.11.7(a), or otherwise the identity of the observer, a description of the measurements that were made, the operating condition of the affected unit, the observed opacity, and copies of the raw data sheets for the measurements.
 - d. The Permittee shall maintain records for the PM emissions of the affected units to verify compliance with the limits in Condition 4.11.6, based on the above records for the affected units including data for implementation of the operating program, and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.
 - e. The Permittee shall maintain the following records related to emissions of fugitive particulate matter from affected units. As records of certain information are to be kept in a file, the Permittee shall review and update such information on a periodic basis so that the file contains accurate information addressing the current circumstances of the source.
 - i. A file that contains information on the length and state of road segments at the plant, the area and state of other open areas at the source traveled by vehicles, and the characteristics of the various categories of vehicles present at the source as necessary to determine emissions.
 - ii. A file that contains information for the emission control efficiency or controlled emission factors (lb/vehicle mile traveled) achieved by the standard management practices

implemented by the Permittee pursuant to its operating program for the various categories of vehicles on the road segments and open areas at the source, based on methodology for estimating emissions published by USEPA, with supporting explanation and calculations.

- iii. For emission that are not controlled or for which emissions are determined by applying a control efficiency to an uncontrolled emission factor, information for the standard emission factors (lb/vehicle mile traveled) used for uncontrolled emissions for the various categories of vehicles on the road segments and open areas at the source, based on methodology for estimating emissions published by USEPA, with supporting explanation and calculations.
- iv. Records of the estimated vehicle miles traveled on each roadway segment or other open area (miles/month, by category of vehicle), with supporting documentation and calculations. These records may be developed from the records for the amount of different materials handled at the source and information in a file that describes how different materials are handled.
- v. Records for each period when standard management practices were not implemented, including a description of the event, an estimate of control measures that were present during the event and an estimate of the additional emissions that occurred during the event.
- vi. Records for emissions, in ton/month, based on the emission factors and other information contained in other required records, with supporting calculations.

4.11.10 Reporting Requirements

- a. The Permittee shall notify the Illinois EPA of deviations with permit requirements in Section 4.11 by affected units as follows. Reports shall describe the probable cause of such deviations, any corrective actions taken, and preventive measures taken and be accompanied by the relevant records for the incident:
 - i. Notification within 30 days for any incident in which 35 IAC 212.301 may have been violated.

4.12 Hydrogen Plant 2 Vents

4.12.1 Description

During startup, shutdown, and malfunction, blowdown and high pressure stripper (HPS) vents at the Hydrogen Plant 2 discharge to the atmosphere. The streams are mainly steam but also contain VOM and CO₂. During normal operation, these streams are recycled back to the process.

4.12.2 List of Emission Units

Location of Vents	Description of Vents
Hydrogen Plant 2 Vents	Blowdown and HPS Vents

4.12.3 Applicable Provisions and Emission Standards

- a. The “affected vents” for the purpose of these unit-specific conditions, are the vents described in Conditions 4.12.1 and 4.12.2.
- b. The affected vents are subject to 35 IAC 219.441(c)(1), which provides that no person shall cause or allow the discharge of organic material into the atmosphere in excess of 8 lb/hour from any waste gas stream from any new petroleum manufacturing process, other than a catalyst regenerator or fluid coker, unless emissions are controlled by at least 85 percent.

4.12.4 Nonapplicability Provisions

The affected vents are not “miscellaneous process vent” subject to 40 CFR 63 Subpart CC because they are “hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced within a hydrogen plant is degassed or deaerated” and are specifically excluded from the definition of miscellaneous process vent in 40 CFR 63.641.

4.12.5 Control Requirements and Work Practices

BACT/LAER Technology for Emissions of GHG and VOM. This condition represents the application of the Best Available Control Technology and the Lowest Achievable Emission Rate for the affected vents.

- a. BACT Emission Limit
 - i. The affected vents shall be operated in accordance with good air pollution control practice to minimize emissions of GHG.
 - ii. Emissions of GHG (as CO₂e) from the affected vents shall not exceed 350 tons per year, running 12-month total.
- b. LAER Emission Limit

- i. The vents shall be operated in accordance with good air pollution control practice to minimize emissions of VOM.
- ii. Emissions of VOM from the affected vents shall not exceed 0.1 tons per year, running 12-month total.

4.12.6 Operating Requirements

The Permittee shall operate the affected units and associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions.

4.12.7 Emission Limits

Emissions from the affected vents shall not exceed the following limits. Compliance with the annual limit shall be determined from a running total of 12 months of data.

GHG (as CO ₂ e) Tons/Year	VOM Tons/Year
350	0.1

4.12.8 Recordkeeping Requirements

The Permittee shall maintain a file that contains a demonstration that the emissions from the affected vents will not exceed the limits in Condition 4.12.7, with supporting documentation and calculations.

4.12.9 Reporting Requirements

For the affected vents, the Permittee shall notify the Illinois EPA of deviations from the requirements of this permit. These notifications shall be submitted within 30 days of such occurrence. Reports shall describe the deviation, the probable cause of such deviation, the corrective actions taken, and any preventive measures taken.

4.13 Boiler 19

4.13.1 Description

Boiler 19 (the "affected boiler") will be fired with refinery fuel gas (RFG) and natural gas. It will be equipped with selective catalytic reduction (SCR) for control of NO_x emissions. This boiler will provide steam for various process units at the refinery. This boiler will be installed to supply steam that was originally expected to be provided by FCCU-3, which is now no longer part of this project.

Boiler 19 would also require fuel supply lines. The fuel supply lines will have the potential for leaks from components such as valves and flanges. These emissions will be addressed by a leak detection and repair (LDAR) program (See Section 4.3).

4.13.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Boiler 19	405 mmBtu/hr RFG/natural gas-fired boiler	SCR

4.13.3 Applicable Emission Standards

- a. The affected boiler is subject to the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63 Subpart DDDDD and applicable requirements of the General Provisions of the NESHAP, 40 CFR 63 Subpart A. In particular, the Permittee shall conduct a tune-up of the affected boiler annually as specified in 40 CFR 63.7540. [40 CFR 63.7500 and Table 3 of 40 CFR 63 Subpart DDDDD]
- b. The affected boiler is subject to the NSPS for Small Industrial, Commercial, and Institutional Steam Generating Units, 40 CFR 60 Subpart Db and the applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A.

Pursuant to the NSPS, 40 CFR 60.44b(i) and (l)(1), as a high heat release rate boiler, the NO_x emissions of the affected boiler shall not exceed 86 ng/J (0.20 lb/million Btu) heat input on a 30-day rolling average, beginning on and after the date on which the initial performance test is completed or is required to be completed under 40 CFR 60.8, whichever date comes first.

Note: The boiler is subject to a more stringent NO_x emission limit, 0.02 lb/mmBtu, pursuant to Condition 4.13.6(a).

- c. The affected boiler is subject to the NSPS for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60 Subpart Ja and the applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A. Pursuant to this NSPS:

- i. The owner or operator shall comply with the emissions limitations in 40 CFR 60.102a(g) on and after the date on which the initial performance test, required by 40 CFR 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first. [40 CFR 60.102a(a)]
 - ii. The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis. [40 CFR 60.102a(g)(1)(ii)]
- d. i. The affected boiler is subject to 35 IAC 212.122(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter into the atmosphere from any fuel combustion emission unit having an opacity greater than 20 percent, except as provided in 35 IAC 212.122(b).
- ii. A. The affected boiler is subject to 35 IAC 216.121, which provides that no person shall cause or allow the emission of CO into the atmosphere from any fuel combustion emission source to exceed 200 ppm, corrected to 50 percent excess air.
 - B. Notwithstanding the above, subject to the following terms and conditions, the Permittee is authorized to operate the affected boiler in violation of 35 IAC 216.121 during startup. This authorization is provided pursuant to 35 IAC 201.149, 201.161 and 201.262, as the Permittee has applied for such authorization in its application, generally describing the efforts that will be used "...to minimize startup emissions, duration of individual starts, and frequency of startups."
 - 1. This authorization does not relieve the Permittee from the continuing obligation to demonstrate that all reasonable efforts are made to minimize startup emissions, duration of individual startups and frequency of startups.
 - 2. The Permittee shall conduct startup of the affected boiler in accordance with written procedures which shall be maintained at the refinery, that are specifically developed to minimize emissions from startups.
 - 3. The Permittee shall fulfill applicable recordkeeping and reporting requirements of Condition 4.13.9(g) and 4.13.10(f).

4. As provided by 35 IAC 201.265, this authorization for excess emissions during startup does not shield a Permittee from enforcement for any violation of applicable emission standard(s) that occurs during startup and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.
- iii. The affected boiler is subject to 35 IAC 217 Subparts D (NO_x General Requirements) and E (Industrial Boilers).
 - i. The affected boiler is subject to 35 IAC 217.164(a), which provides that no person shall cause or allow emissions of NO_x into the atmosphere from a subject boiler to exceed 0.08 lb/mmBtu, on an ozone season and annual average basis.
 - ii. The above requirement takes effect beginning January 1, 2015. [35 IAC 217.152(a)]

4.13.4 Nonapplicability Provisions

The affected boiler is subject to 35 IAC 217 Subpart U: NO_x Control and Trading Program for Specified NO_x Generating Units; however, because of the Sunset Provisions in 35 IAC 217.451, only the applicable requirements of 35 IAC 217.454(a) and (b) and 217.456(c), (e)(1)(B) through (D), and (e)(2) apply (See also Conditions 4.13.8 and 4.13.9).

4.13.5 Control Requirements and Work Practices

- a.
 - i. BACT/LAER Technology for Emissions of CO, GHG and VOM. This condition represents the application of the Best Available Control Technology and the Lowest Achievable Emission Rate.

The affected boiler shall be designed, maintained and operated with good combustion practices to reduce emissions of CO, GHG and VOM.
 - ii. BACT Emission Limit
 - A. Emissions of CO from the affected boiler shall not exceed 0.02 lb/mmBtu, HHV, 30-day average.
 - B. Emissions of GHG, expressed as CO₂e, from the affected boiler shall not exceed 0.168 lb CO₂e per lb steam produced on a 12-month rolling average.
 - iii. LAER Emission Limit

Emissions of VOM from the affected boiler shall not exceed 0.003 lb/mmBtu, HHV, 30-day average.

Condition 4.13.5(a)(i) and (ii) represents the application of Best Available Control Technology. Condition 4.13.4(a)(i) and (iii) represents the application of Lowest Achievable Emission Rate.

- b. For the affected boiler, the Permittee shall comply with the requirements of the NSPS, 40 CFR 60.103a, related to SO₂ exceedances, including:
 - i. Conducting a root cause analysis and a corrective action analysis for each exceedance of the applicable short-term emissions limit in 40 CFR 60.102a(g)(1) if the SO₂ discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limit had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter. These analyses must be completed as soon as possible, but no later than 45 days after a discharge meeting this criterion, as further provided by 40 CFR 60.103a(d)(1) and (5). [40 CFR 60.103a(c)(2) and (d)]
 - ii. Implementing the corrective action(s) identified in the above corrective action analysis in accordance with the applicable requirements in 40 CFR 60.103a(e). [40 CFR 60.103a(e)]
- c. At all times, the Permittee shall operate and maintain the affected boiler, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. [40 CFR 63.7500(a)(3)]
- d. The Permittee shall conduct an annual tune-up of the affected boiler in accordance with 40 CFR 63.7540(a)(10).
- e. The affected boiler is subject to 35 IAC 217.150(e) and 217.152, which provide that beginning January 1, 2015, the owner or operator a boiler shall operate the boiler in a manner consistent with good air pollution control practice to minimize NO_x emissions.

4.13.6 Operational and Emission Limits

- a. The rated heat input capacity of the affected boiler shall not exceed 405 mmBtu/hour (HHV).
- b. Refinery fuel gas and natural gas shall be the only fuels fired in the affected boiler.
- c. The affected boiler shall be equipped with SCR designed to emit no more than 0.02 lb NO_x per million Btu heat input (HHV), on a 12-month rolling average basis.

- d. The emissions of the affected boiler shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data.

Pollutant	Limits	
	Lbs/Hour	Tons/Year
CO	---	35.5
NO _x	---	35.5
SO ₂	26.0	27.4
PM/PM ₁₀ /PM _{2.5}	3.0	13.1
VOM	1.2	5.3
GHG, as CO ₂ e	---	206,000

4.13.7 Testing and Inspection Requirements

- a. The affected boiler is subject to 40 CFR 60.46b(e), which provides that the owner or operator shall conduct the performance test as required under 40 CFR 60.8 using the continuous system for monitoring NO_x under 40 CFR 60.48(b) to determine compliance with the emission limits for NO_x required under 40 CFR 60.44b.
- b. The Permittee shall have performance tests conducted for the affected boiler to demonstrate initial compliance with the applicable emissions limits in 40 CFR 60.102a according to the requirements of 40 CFR 60.8 and 40 CFR 60.104a, as follows. The notification requirements of 40 CFR 60.8(d) apply to the initial performance test, but do not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments. Compliance with the applicable H₂S emissions limit in 40 CFR 60.102a(g)(1) shall be determined according to the test methods and procedures specified in 40 CFR 60.104a(j). [40 CFR 60.104a(a) and (j)]

Note: If monitoring is conducted at a single point in a common source of fuel gas as allowed under 40 CFR 60.107a(a)(2)(iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance, pursuant to 40 CFR 60.104a(j)(4)(iv).

- c. i. The Permittee shall have emissions testing conducted for the affected boiler as follows, at its expense by a qualified testing service under representative operating conditions, for emissions of PM, filterable PM₁₀ and PM_{2.5}, condensable PM, VOM, methane and N₂O provided, however, that if the Permittee considers all filterable PM₁₀ emissions to be emissions of filterable PM_{2.5}, testing for emissions of filterable PM_{2.5} need not be performed unless specifically requested by the Illinois EPA.
- ii. This testing shall be conducted as follows:

- A. Within 60 days after achieving the maximum production rate at which the affected boiler will be operated, but not later than 180 days after initial startup of the affected boiler.
 - B. On a periodic basis thereafter, with testing conducted between four and five years from the date of the previous test.
 - C. In addition, the Permittee shall perform emission tests as provided below as requested by the Illinois EPA within 90 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA.
- iii. Appropriate USEPA test methods, including the following methods, shall be used for testing, unless other methods adopted by or being developed by USEPA or other alternative test methods are approved by the Illinois EPA.

Filterable PM	USEPA Method 5
Filterable PM ₁₀ /PM _{2.5}	USEPA Method 5 or 201A
Condensable PM	USEPA Method 202
VOM	USEPA Method 18 or 25A
N ₂ O and methane	USEPA Method 320

4.13.8 Monitoring Requirements

- a.
 - i. The affected boiler is subject to 40 CFR 60.48b(b)(1), which provides that the owner or operator shall install, calibrate, maintain, and operate CEMS for measuring NO_x and O₂ (or CO₂) emissions discharged to the atmosphere, and shall record the output of the system.
 - A. The CEMS shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks, and zero and span adjustments. [40 CFR 60.48b(c)]
 - B. The 1-hour average NO_x emission rates measured by the CEMS shall be expressed in ng/J or lb/mmBtu heat input and shall be used to calculate the average emission rates under 40 CFR 60.44b. The 1-hour averages shall be calculated using the data points required under 40 CFR 60.13(h)(2). [40 CFR 60.48b(d)]
 - C. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the CEMS. [40 CFR 60.48b(e)]
 - D. The span value for NO_x shall be 500 ppm. [40 CFR 60.48b(e)(2)]

- E. When NO_x emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 or 7A of 40 CFR 60 Appendix A or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days. [40 CFR 60.48b(f)]
- ii. For NO_x, the affected boiler is also subject to 35 IAC 217.456(c)(1), which provides that the owner or operator shall comply with the monitoring requirements of 40 CFR 96 Subpart H. The Permittee shall comply with the applicable monitoring requirements of 40 CFR 96 Subpart H. [35 IAC 217.456(c)(1)]
- b. For the affected boiler, the Permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gas before being burned in the boiler, as follows: [40 CFR 60.107a(a)(2)]
 - i. The Permittee shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of Appendix B to 40 CFR Part 60. The span value for this instrument is 300 ppmv H₂S.
 - ii. The Permittee shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR 60.13(c) and Performance Specification 7 of Appendix B to 40 CFR Part 60. The Permittee shall use Method 11, 15, or 15A of Appendix A-5 to 40 CFR Part 60 or Method 16 of Appendix A-6 to 40 CFR Part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," as incorporated by reference in 40 CFR 60.17, is an acceptable alternative to USEPA Method 15A of Appendix A-5 to 40 CFR Part 60.
 - iii. The Permittee shall comply with the applicable quality assurance procedures in Appendix F to 40 CFR Part 60 for each H₂S monitor.
 - iv. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned in the respective fuel gas combustion devices.
- c. The Permittee shall calibrate, maintain and operate a continuous emissions monitoring system for emissions of CO from the affected boiler that meets 40 CFR 60 Appendix B, Performance Specification

- ii. For NO_x, the affected boiler is also subject to 35 IAC 217.456(c)(1), which provides that the owner or operator shall comply with the monitoring requirements of 40 CFR 96 Subpart H. The Permittee shall comply with the applicable monitoring requirements of 40 CFR 96 Subpart H. [35 IAC 217.456(c)(1)]

- b. For the affected boiler, the Permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gas before being burned in the boiler, as follows: [40 CFR 60.107a(a)(2)]

- i. The Permittee shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of Appendix B to 40 CFR Part 60. The span value for this instrument is 300 ppmv H₂S.
- ii. The Permittee shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR 60.13(c) and Performance Specification 7 of Appendix B to 40 CFR Part 60. The Permittee shall use Method 11, 15, or 15A of Appendix A-5 to 40 CFR Part 60 or Method 16 of Appendix A-6 to 40 CFR Part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," as incorporated by reference in 40 CFR 60.17, is an acceptable alternative to USEPA Method 15A of Appendix A-5 to 40 CFR Part 60.
- iii. The Permittee shall comply with the applicable quality assurance procedures in Appendix F to 40 CFR Part 60 for each H₂S monitor.
- iv. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned in the respective fuel gas combustion devices.

- c. The Permittee shall calibrate, maintain and operate a continuous emissions monitoring system for emissions of CO from the affected boiler that meets 40 CFR 60 Appendix B, Performance Specification

4. This monitoring system shall be operated in accordance with 40 CFR 60.7(c), 60.13, and Performance Specification 4, Appendix B, including associated recordkeeping and reporting requirements.

- d. For the affected boiler, the Permittee shall install, calibrate, maintain, and operate a CEMS for measuring CO₂ emissions discharged to the atmosphere (in terms of lbs/hour) and shall record the output of the system. The CEMS shall be operated in accordance with either (i) or (ii) below:
 - i. A. 40 CFR 60.13
 - B. 40 CFR 60 Appendix B, Performance Specifications 3 and 6
 - C. 40 CFR 60 Appendix F
 - ii. A. 40 CFR 75, including 40 CFR 75.10(a)(3)
 - B. Data reported shall not include data substituted using the missing data procedures in 40 CFR 75 Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR 75.

4.13.9 Recordkeeping Requirements

- a. For the affected boiler, the Permittee shall comply with the applicable recordkeeping requirements of the NESHAP, including 40 CFR 63.7555.
- b. For the affected boiler, the Permittee shall comply with the applicable recordkeeping requirements of the NSPS, 40 CFR 60.49b, including:
 - i. The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day. [40 CFR 60.49b(d)(1)]
 - ii. The owner or operator shall maintain records of the following information for each unit operating day: [40 CFR 60.49b(g)]
 - A. Calendar date.
 - B. The average hourly NO_x emission rates (expressed as NO₂) (ng/J or lb/mmBtu heat input) measured or predicted.
 - C. The 30-day average NO_x emission rates (ng/J or lb/mmBtu heat input) calculated at the end of each unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 unit operating days.

- D. Identification of the unit operating days when the calculated 30-day average NO_x emission rates are in excess of the NO_x emissions standards under 40 CFR 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.
 - E. Identification of the unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.
 - F. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.
 - G. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
 - H. Identification of the times when the pollutant concentration exceeded full span of the CEMS.
 - I. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3.
 - J. Results of daily CEMS drift tests and quarterly accuracy assessments as required under 40 CFR 60 Appendix F, Procedure 1.
- c. For the affected boiler, the Permittee shall comply with the applicable recordkeeping requirements in 40 CFR 60.7 and other requirements as specified 40 CFR 60.108a. [40 CFR 60.108a(a)]
 - d.
 - i. For the affected boiler, the Permittee shall comply with the applicable recordkeeping requirements of 35 IAC 217.156.
 - ii. The affected boiler is subject to 35 IAC 217.456(e)(1)(B) through (D), which provides that the owner or operator shall keep at the source each of the documents listed in below for a period of 5 years from the date the document is created. This period may be extended for cause at any time prior to the end of 5 years in writing by the Illinois EPA or USEPA.
 - A. All emissions monitoring information, in accordance with 35 IAC 217.456(c), provided that to the extent that 40 CFR 96 Subpart H, provides for a three-year period for recordkeeping, the three-year period shall apply.
 - B. Copies of all reports and other submissions and all records made or required under 35 IAC 217 Subpart U

or documents necessary to demonstrate compliance with the requirements of 35 IAC 217 Subpart U.

- C. Copies of all documents and any other submission under 35 IAC 217 Subpart U.
- iii. The Permittee shall submit to the Illinois EPA and USEPA the reports required under 35 IAC 217 Subpart U, including those reports under 40 CFR 96 Subpart H. [35 IAC 217.456(e)(2)]
- e. The Permittee shall maintain records of the following for the affected boiler:
 - i. The quantity of fuel burned (mmBtu/month and mmBtu/year), with supporting documentation including heat content of the fuel burned.
 - ii. The amount of steam produced (pounds/month and pounds/year).
 - iii. Records for the sulfur content of the fuel gas that addresses all sulfur compounds in the fuel gas, based on a combination of continuous monitoring for H₂S and periodic sampling and analysis for other sulfur compounds.
- f. The Permittee shall keep the following records related to the emissions of NO_x, CO, VOM, SO₂, PM, PM₁₀/PM_{2.5}, and GHG (expressed as CO₂e) from the affected boiler:
 - i. A file that documents the rated heat input capacity of the boiler (mmBtu/hour, HHV), the maximum design emission rates (lbs/mmBtu and lbs/hour) for NO_x, CO, PM/PM₁₀/PM_{2.5}, VOM and SO₂ based on continuous emissions monitoring data if a monitor is installed or performance testing if a monitor is not installed.
 - ii. For NO_x, CO and CO₂, the emissions of the pollutant based on continuous emissions monitoring data, in tons/month and tons/year.
 - iii. For PM/PM₁₀/PM_{2.5}, VOM, CH₄ and N₂O:
 - A. A file containing the emission factors that are used to calculate emissions, with supporting documentation; and
 - B. The emissions of the pollutant based on operating data and applicable emission factors, in tons/month and tons/year, with supporting calculations.
 - iv. For GHG, emissions as CO₂e, based on the above data for emissions of CO₂ and of CH₄ and N₂O, in tons/month and tons/year.

- v. GHG emissions, in pounds of GHG, as CO₂e, per pound of steam produced, annual average, calculated for each month in which the boiler is operational.
- g. The Permittee shall maintain the following records related to startup for the affected boiler:
 - i. Date and duration of each startup, i.e., start time and time normal operation is achieved.
 - ii. For each startup in which refractory must be cured after maintenance and each other startup if normal operation was not achieved within 6 hours:
 - A. A detailed description of the startup, including whether startup was conducted in accordance with the written procedures required by Condition 4.13.3(d)(ii)(B)(2) and why the startup could have been completed more quickly.
 - B. An explanation why established startup procedures could not be performed, if not performed.
 - C. Whether exceedance of 35 IAC 216.121 may have occurred during startup. If an exceedance may have occurred, an explanation of the severity and duration during the startup and at the conclusion of startup.
 - iii. A maintenance and repair log for the affected boiler, listing each activity performed with date.

4.13.10 Reporting Requirements

- a. For the affected boiler, the Permittee shall comply with the applicable reporting and notification requirements of the NESHAP, including 40 CFR 63.7550 and 63.7545.
- b. For the affected boiler, the Permittee shall comply with the applicable notification and reporting requirements of the NSPS, 40 CFR 60.49b, including:
 - i. The owner or operator shall submit notification of the date of initial startup, as provided by 40 CFR 60.7. This notification shall include the information in 40 CFR 60.49b(a)(1)-(4).
 - ii. The owner or operator shall submit to the Illinois EPA and USEPA the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in 40 CFR 60 Appendix B.

- iii. The owner or operator shall submit excess emission reports for any excess emissions that occurred during the reporting period. [40 CFR 60.49b(h)]
- iv. The owner or operator shall submit reports containing the information recorded under 40 CFR 60.49b(g). [40 CFR 60.49b(i)]
- c. For the affected boiler, the Permittee shall comply with the notification and reporting requirements in the NSPS, including 40 CFR 60.7 and 60.108a(a).
- d. For the affected boiler, the Permittee shall comply with the applicable reporting requirements of 35 IAC 217.156.
- e. For the affected boiler, the Permittee shall notify the Illinois EPA of deviations from the requirements of this permit. Unless otherwise provided by the applicable reporting requirement of the NSPS or NESHAP, these notifications shall be submitted within 30 days of such occurrence. Reports shall describe the deviation, the probable cause of such deviation, the corrective actions taken, and any preventive measures taken.
- f. Reporting of Startups

The Permittee shall submit semi-annual startup reports to the Illinois EPA. These reports may be submitted along with other semi-annual reports required for the source, e.g., CAAPP semi-annual reports, and shall include the following information for startups of the affected boiler during the reporting period:

- i. A list of the startups of the affected boiler, including the date, duration and description of each startup, accompanied by a copy of the records pursuant to Condition 4.13.9(g) for each startup for which such records were required.
- ii. If there have been no startups of the affected boiler during the reporting period, this shall be stated in the report.

5.0 ATTACHMENTS

Attachment 1a: Summary of Emissions Increases for the Project (Tons/Year)
(based on the revisions to the project)

Operation	NA NSR				PSD							
	VOM	NO _x	PM _{2.5} *	SO ₂	CO	NO _x	SO ₂	PM	PM ₁₀	GHG	H ₂ S	TRS
Refinery CORE Increases												
Heaters/Boilers	53.2	868.4	118.9	1,465.0	467.6	868.4	1,465.0	118.9	118.9	206,000	---	---
DCU-2 Vent, Cutting, Quench	8.4	---	1.1	---	---	---	---	1.1	1.1	2,500	5.5	---
Components	43.0	---	---	---	---	---	---	---	---	50	0.3	0.5
Tanks	113.6	---	---	---	---	---	---	---	---	---	---	---
FCCU's	8.0	---	---	---	295.4	---	---	---	---		---	---
Cooling Water Towers	8.0	---	1.9	---	---	---	---	29.2	16.2	---	---	---
Flares	16.5	15.2	---	191.8	76.1	15.2	191.8	---	---	400	---	---
Sulfur Recovery Units	2.8	36.8	3.9	437.4	43.3	36.8	437.4	3.9	3.9		---	---
Fugitive PM Emission Units	---	---	23.9	---	---	---	---	69.7	23.9		---	---
WWTP Secondary Treatment	44.5	---	---	---	---	---	---	---	---		---	---
Roadways & Other Open Areas	---	---	11.6	---	---	---	---	59.3	11.6		---	---
Hydrogen Plant 2 Vents	0.1	---	---	---	---	---	---	---	---	350	---	---
SUBTOTAL:	298.1	920.4	161.3	2,094.2	882.4	920.4	2,094.2	282.1	175.6	209,300	5.8	0.5
Terminal CORE Increases	29.2	---	---	---	---	---	---	---	---	50	---	---
TOTAL:	327.3	920.4	161.3	2,094.2	882.4	920.4	2,094.2	282.1	175.6	209,350	5.8	0.5
Significance Threshold:	40	40	10	40	100	40	40	25	15	75,000	10	10
Greater Than Significant?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No

Attachment 1b: Project Emissions Summary (Tons/Year)
(based on the revisions to the project)

	NA NSR				PSD							
	VOM	NO _x	PM _{2.5} *	SO ₂	CO	NO _x	SO ₂	PM	PM ₁₀	GHG	H ₂ S	TRS
CORE Project Increases:	327.3	920.4	161.3	2,094.2	882.4	920.4	2,094.2	282.1	175.6	209,350	5.8	0.5
CORE Project Decreases:	1.2	1,045.9	132.4	11,131.3	27.9	1,045.9	11,131.3	132.4	132.4	0	0	0
TOTAL:	326.1	-125.5	28.9	-9,037.1	854.5	-125.5	-9,037.1	149.7	43.2	209,350	5.8	0.5

Attachment 2: Netting Analysis for the Project (Tons/Year)^a (based on the revisions to the project)

	Date	Permit	NA NSR			PSD			
			NO _x	PM _{2.5}	SO ₂	NO _x	SO ₂	PM	PM ₁₀
Project Emissions Increases			920.4	161.3	2,094.2	920.4	2,094.2	282.1	175.6
Project Emissions Decreases			-1,045.9	132.4	-11,131.3	-1,045.9	-11,131.3	132.4	132.4
Project Subtotal:			-125.5	28.9	-9,037.1	-125.5	-9,037.1	149.7	43.2
Contemporaneous Increases									
RAU Steam Reboiler (Boiler 17)	10/2001	01060090	24.8	---	---	---	---	---	---
FCCU 1 Alterations (Boiler 17)	9/2003	03030069	1.8	0.1	0.6	1.8	0.6	0.1	0.1
Low Sulfur Gasoline, Tier 2	11/2003	01120044	99.2	5.4	37.9	99.2	37.9	5.4	5.4
Hartford Integration	4/2004	03080006	524.2	---	17.3	524.2	17.3	---	---
Ultra Low Sulfur Diesel	4/2006	04050026	225.3	42.2	57.5	157.8	57.5	42.2	42.2
Low Sulfur Gasoline (SZU)	2/2007	05050062	20.6	10.9	31.9	20.6	31.9	10.9	10.9
North Property Flare	6/2007	06030049	1.2	---	0.1	1.2	0.1	---	---
DW Process Heater Project	1/2009	08090014	17.6	2.4	25.9	17.6	25.9	2.4	2.4
Cat Reformer Unit 3 Changes	8/2010	10060028	---	2.6	14.6	---	14.6	2.6	2.6
Cooling Water Tower #13	3/2011	11010026	---	0.5	---	---	---	1.0	0.5
Steam System Alterations	5/2011	08020003	---	4.8	28.7	---	28.7	4.8	4.8
Rental Boilers	9/2012	11070026	28.0	2.6	0.5	28.0	0.5	2.6	2.6
Replacement TO for Marine Loading	3/2013	13030018	0.3	---	---	0.3	---	---	---
ULD Optimization	6/2013	13040030	14.9	2.5	31.6	14.9	31.6	2.6	2.5
Tier 3 Low Sulfur Gasoline	Est 2014	14050001	24.4	1.1	12.0	24.4	12.0	1.5	1.3
Contemporaneous Decreases									
RAU Deethanizer Heater Shutdown	10/2001	92110025	-19.6	-1.5	---	---	---	---	---
CR-1 2 nd Inter-reactor Heater, H-3	2/2002	92110025	-32.1	-3.0	---	---	---	---	---
CR-1 2 nd Inter-reactor Heater, H-2	2/2002	92110025	-19.1	-6.4	---	---	---	---	---
CR-1 Feed Preheater, H-1	2/2002	92110025	-19.5	-6.5	---	---	---	---	---
No. 2 Crude Unit, H-25	10/2002	03080006	-29.7	-0.6	-0.8	-29.7	-0.8	-0.6	-0.6
Isom Unit, H-33 (HIP)	10/2002	03080006	-2.5	-0.1	-0.1	-2.5	-0.1	-0.1	-0.1
Isom Unit, H-32 (HIP)	10/2002	03080006	-10.8	-0.2	-0.3	-10.8	-0.3	-0.2	-0.2
LSR Hydrotreating, H-31 (HIP)	10/2002	03080006	-1.7	---	---	-1.7	---	---	---
Hydrogen Plant, H-30 (HIP)	10/2002	03080006	-10.0	-0.2	-0.3	-10.0	-0.3	-0.2	-0.2
Alkylation Heater, H-19 (HIP)	10/2002	03080006	-20.8	-0.4	-0.6	-20.8	-0.6	-0.4	-0.4
Reroute/Eliminate Flare Streams	10/2002	03080006	-17.4	---	---	-17.4	---	---	---
FCCU Shutdown at Hartford	10/2002	03080006	-320.0	-323.3	-73.9	-320.0	-73.9	-323.3	-323.3
CR-3 2 nd Reheat Heater	11/2002	92110025	-86.7	-5.8	-339.0	-86.7	-339.0	-11.1	-8.0
CR-3 1 st Reheat Heater	11/2002	92110025	-113.1	-10.9	-646.6	-113.1	-646.6	-21.1	-15.4
CR-3 Charge Heater (fuel switch)	11/2002	92110025	-115.8	-11.2	-663.0	-115.8	-663.0	-21.6	-15.6
Shutdown RFP	12/2002	92110025	-2.6	-0.2	---	-2.6	---	-0.2	-0.2
Shutdown Old NP Ground Flare	7/2007	06030049	-1.5	---	-2.9	-1.5	-2.9	---	---
Contemporaneous Changes Subtotal ^c :			159.4	-295.2	-1,468.9	157.4	-1,468.9	-302.7	-288.7
NET EMISSIONS CHANGE ^c :			33.9	-266.3	-10,506.0	31.9	-10,506.0	-153.0	-245.5
Significance Threshold:			40	10	40	40	40	25	15
Greater Than Significant?			No	No	No	No	No	No	No

Notes:

--- Minimal or no increase.

- a. Netting is not performed for H₂S or TRS emissions because the project increase for these pollutants is less than significant (See Attachment 1).
- b. The contemporaneous time period for PSD pollutants begins July 2002. The contemporaneous time period for Nonattainment Area NSR pollutants begins May 2001.
- c. Totals may not match sum of individual unit totals due to rounding.

Attachment 3a - Summary of BACT/LAER Determinations for CO and VOM

Operation	Permit Section	BACT Determination for CO Control Technology/Emission Limit	LAER Determination for VOM Control Technology/Emission Limit
Process Heaters	4.1	Good combustion practices/0.02 lb/mmBtu, HHV	Good combustion practices/0.003 lb/mmBtu, HHV.
Components	4.3	N/A.	LDAR program equivalent to 40 CFR 63 Subpart H with a leak definition of 500 ppm for valves in gas and light liquid service and 2000 ppm pumps in light liquid service. After issuance of revised CORE permit, certain valves will be low emission valves and pumps will have dual mechanical seals.
Storage Tanks	4.4	N/A.	Internal Floating Roof with primary and secondary seals.
Catalytic Cracking Units	4.5	FCCU 1 and FCCU 2: CO Heater or other combustion device; 100 ppmvd corrected to 0% O ₂ (365 rolling day avg.) and 500 ppmvd corrected to 0% O ₂ on hourly average.	Good air pollution control practices/FCCU 1 and FCCU 2: 0.05 lb/1000 lb of coke burned;
Cooling Water Towers	4.6	N/A.	0.006 percent design drift loss for CWT-23, 24, and 25. 0.005 percent design drift loss for CWT-26.
New and Modified Flares	4.7	Good operating practices; 40 CFR 60.18; Flare Gas Recovery System with redundant compressors for Delayed Coking Unit; enhanced Flare Minimization Plan, including Root Cause Analyses; unit-specific limits on use of fuel gas for pilot and purge flows for new flares; and secondary BACT limits for annual CO emissions for new flares.	Good operating practices; 40 CFR 60.18; Flare Gas Recovery System with redundant compressors for Delayed Coking Unit; enhanced Flare Minimization Plan, including Root Cause Analyses; unit-specific limits on use of fuel gas for pilot and purge flows for new flares.
Sulfur Recovery Units "E" and "F"	4.8	Good combustion practices/0.082 lb/mmBtu, HHV.	0.005 lb/mmBtu, HHV.
Wastewater Treatment Plant	4.10	N/A.	Good air pollution control practices.
Process Vents	4.12	N/A.	Hydrogen Plant Vents - good design and air pollution control practice
Boiler 19	4.13	Good combustion practices; 0.02 lb/mmBtu, HHV, 30-day average	Good combustion practices; 0.003 lb/mmBtu, HHV, 30-day average.

Attachment 3b - Summary of BACT Determinations for GHG

Operation	Permit Section	BACT Determination for GHG Control Technology/Emission Limit
Components	4.3	Same as LAER requirements for components for control of VOM emissions from affected components that were added or modified as part of this revised permit.
Process Vents	4.12	Hydrogen Plant Vents - good design and air pollution control practice
Boiler 19	4.13	Good combustion practices; 0.168 lb CO ₂ e/lb steam produced, 12-month rolling average.

ATTACHMENT 4

Procedures for Calculating CO and VOM Emissions from New Flares

The following procedures shall be used to calculate the emissions of CO and VOM from the flares for the new Delayed Coker Unit and new Hydrogen Plant. Other alternative method(s) may be used for these calculations provided they have has been approved in the CAAPP Permit for the source.

General Procedures for Calculation of Emissions

The following equations and emission factors shall be used to calculate CO and VOM emissions from combustion of vent gas, natural gas, propane and butane:

Vent Gas

Pollutant	Equation	Emission Factor (EF)
CO	$E = EF \times V \times LHV$	0.37 lb/mmBtu
VOM	$E = EF \times V \times LHV$	0.063 lb/mmBtu

Where:

E = Calculated vent gas emissions (lbs)

EF = Emission Factor

V= Volume flow of vent gas, in million standard cubic foot (mmscf), with standard conditions at 14.7 psia and 68°F, appropriately determined based on the type of flow monitoring system(s) that are being operated, as discussed below.

LHV = Lower Heating Value of vent gas, as determined in Btu/scf. For a flaring event where a representative sample or other sampling method is not required, use LHV from any representative sample of a flaring event on the same day. If no representative sample is taken on that day, use LHV calculated from the last representative sample taken prior to the flaring event. The LHV of the vent gas may be adjusted to exclude the contribution from free (elemental) hydrogen present in the vent gas based on analysis of representative samples taken during the flaring event or, otherwise, other representative samples of the vent gas.

$$LHV_{\text{adjusted}} = LHV_{\text{measured}} - 225 \text{ Btu/scf} \times \{\text{free hydrogen content (\% by volume)}/100\}$$

Commercial Fuels

Pollutant	Natural Gas		Propane and Butane	
	Equation	EF	Equation	EF
CO	$E = V \times EF$	35 lb/mmscf	$E = V \times 3500 \times EF$	0.032 lb/mmBtu
VOM	$E = V \times EF$	7 lb/mmscf	$E = V \times 3500 \times EF$	0.003 lb/mmBtu

Procedures for Determining Volume Flow of Vent Gas to the Flare

Flow Monitoring with Single On/Off Flow Indicator Switch:

The flow rate setting of the on/off flow indicator switch if the switch is not actuated or the maximum design capacity of the flare for the flow rate for each flaring event.

Flow Monitoring with Multiple On/Off Flow Indicator Switch:

- a) The flow rate setting of the first stage on/off flow indicator switch if the switch is not actuated.
- b) When an on/off switch is actuated assume the flow rate is the flow rate that would actuate the on/off switch set at the next highest flow rate.
- c) Use the maximum design capacity of the flare for the flow rate when the on/off switch set for the highest flow rate is actuated.

Flow Monitoring with Flow Meters Only:

- a) Use the recorded flow meter data until the maximum range is exceeded.
- b) When the maximum range of the flow meter is exceeded, assume the flow rate is the maximum design capacity of the flare(s), unless the Permittee demonstrates a calculated flow based upon credible operational parameters and process data that represent the flow during the period of time that the flow exceeded the maximum range of the flow meter.
- c) When the flow rate is below the valid lower range of the flow meter, assume the flow rate is at the lower range.

Flow Monitoring with Combination of Flow Meters and On/Off Flow Indicator Switches:

- a) Use the recorded flow meter data until the maximum range is exceeded.
- b) When the maximum range of the flow meter is exceeded, assume the flow rate is the flow rate that would actuate the on/off switch set at the next highest flow rate.
- c) Use the maximum design capacity of the flare for the flow rate when the on/off switch set for the highest flow rate is actuated.
- d) When the flow rate is below the valid lower range of the flow meter, assume the flow rate is at the lower range.
- e) When the flow rate is below the valid lower range of the flow meter and the set flow rate of an on/off switch, assume the flow rate is the flow rate that would actuate the on/off switch.

Special Procedures for Calculation of Emissions with Data Substitution

For any time period for which the vent gas flow or the lower heating value of vent gas are not measured, analyzed and recorded by the Permittee pursuant to the applicable regulatory and permit requirements, unless the Permittee demonstrates using records of flare water seal level and/or other credible operating information that no flaring event occurred during the period when these parameters were not measured, analyzed or recorded, the following values shall be serve in place of the missing data:

Missing Data for Flow Rate

If the flow rate is not measured or recorded for any flaring event, the totalized flow shall be calculated using the methodology below unless a credible determination of totalized flow can be made using recorded and verifiable operational parameters and/or process data, including reference to similar events that have previously occurred.

The totalized flow shall be calculated from the product of the flaring event duration and the estimated flow rate. The flow rate shall be calculated using the following equation for the period of time the flow meter was out of service:

$$FR = \text{Max. } FR_{\text{max}} - 0.5 \times (FR_{\text{max}} - FR_{\text{ave}})$$

Where:

FR = Estimated Flow Rate (scfm)

FR_{max} = Maximum flow rate that was measured and recorded for the flare during previous operation preceding the subject flaring event (up to the previous 20 quarters). This maximum value is based on the average flow rate during an individual flaring event, not an instantaneous maximum value during a flaring event.

FR_{ave} = Average flow rate for all measured and recorded flow rates for all sampled flaring events for that flare during previous operation preceding the subject flaring event.

The duration of a flaring event during periods when the flow meter is out of service shall be determined using an alternate method set forth in the current Flare Monitoring and Recording Plan. In the absence of an alternate method to determine the duration of a flaring event during periods when the flow meter is out of service, the Permittee shall report the flare to be venting for the entire time the flow meter is out of service.

Missing Data for Lower Heating Value of Vent Gases

If the lower heating value of vented gas is not measured or recorded for any flaring event, the lower heating value shall be calculated using the methodology below, unless a credible determination of lower heating value can be made using recorded and verifiable operational parameters and/or process data, including reference to similar events that have previously occurred.

The lower heating value shall be calculated using the following equation for the period of time this parameter was not measured or recorded:

$$\text{LHV} = \text{LHV}_{\text{max}} - 0.5(\text{LHV}_{\text{max}} - \text{LHV}_{\text{ave}})$$

Where:

LHV = Estimated lower heating value (Btu/scf)

LHV_{max} = Maximum LHV of vent gas measured and recorded for that flare during previous operation preceding the subject flaring event (up to the previous 20 quarters).

LHV_{ave} = Average value of all LHV of vent gas measured and recorded for that flare for all sampled flaring events during previous operation preceding the subject flaring event (up to the previous 20 quarters).

ATTACHMENT 5: STANDARD PERMIT CONDITIONS

STANDARD CONDITIONS FOR CONSTRUCTION/DEVELOPMENT PERMITS
ISSUED BY THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) authorizes the Environmental Protection Agency to impose conditions on permits, which it issues.

The following conditions are applicable unless superseded by special condition(s).

1. Unless this permit has been extended or it has been voided by a newly issued permit, this permit will expire one year from the date of issuance, unless a continuous program of construction or development on this project has started by such time.
2. The construction or development covered by this permit shall be done in compliance with applicable provisions of the Illinois Environmental Protection Act and Regulations adopted by the Illinois Pollution Control Board.
3. There shall be no deviations from the approved plans and specifications unless a written request for modification, along with plans and specifications as required, shall have been submitted to the Illinois EPA and a supplemental written permit issued.
4. The Permittee shall allow any duly authorized agent of the Illinois EPA upon the presentation of credentials, at reasonable times:
 - a. To enter the Permittee's property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit,
 - b. To have access to and to copy any records required to be kept under the terms and conditions of this permit,
 - c. To inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit,
 - d. To obtain and remove samples of any discharge or emissions of pollutants, and
 - e. To enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring, or recording any activity, discharge, or emission authorized by this permit.
5. The issuance of this permit:

- a. Shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are to be located,
 - b. Does not release the Permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the proposed facilities.
 - c. Does not release the Permittee from compliance with other applicable statutes and regulations of the United States, of the State of Illinois, or with applicable local laws, ordinances and regulations.
 - d. Does not take into consideration or attest to the structural stability of any units or parts of the project, and
 - e. In no manner implies or suggests that the Illinois EPA (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.
- 6a. Unless a joint construction/operation permit has been issued, a permit for operation shall be obtained from the Illinois EPA before the equipment covered by this permit is placed into operation.
- b. For purposes of shakedown and testing, unless otherwise specified by a special permit condition, the equipment covered under this permit may be operated for a period not to exceed thirty (30) days.
7. The Illinois EPA may file a complaint with the Board for modification, suspension or revocation of a permit.
- a. Upon discovery that the permit application contained misrepresentations, misinformation or false statement or that all relevant facts were not disclosed, or
 - b. Upon finding that any standard or special conditions have been violated, or
 - c. Upon any violations of the Environmental Protection Act or any regulation effective thereunder as a result of the construction or development authorized by this permit.