217/782-2113

CONSTRUCTION PERMIT/PSD APPROVAL
NESHAP SOURCE – NSPS SOURCE

PERMITTEE

ConocoPhillips Wood River Refinery
Attn: David W. Dunn
900 South Central Avenue
Roxana, Illinois 62084

Application No.: 06050052 I.D. No.: 119090AAA
Applicant's Designation: WRR-87 Date Received: May 15, 2006
Subject: Coker and Refinery Expansion (CORE) Project
Date Issued: August 5, 2008
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 Schnepp at 217/782-2113.

Edwin C. Bakowski, P.E. Date Signed: ____________________
Acting Manager, Permit Section
Division of Air Pollution Control

ECB:JMS:jws

cc: Region 3
Lotus Notes
CES

TABLE OF CONTENTS

1.0 LIST OF ABBREVIATIONS AND ACRONYMS COMMONLY USED

AP-42	*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
BACT	Best Available Control Technology
bbl	Barrel
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. ConocoPhillips Company, Defendant," entered in the United States District Court for the Southern District of Texas, Civil Action No. H-05-0258, on January 27, 2005
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_2S	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
mg	Milligram
Mg	Megagram
MACT	Maximum Achievable Control Technology
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 a. 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).

b. 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's CORE project and the changes to the Wood River Products Terminal to comprise a single larger project for the purpose of PSD/NA NSR.

2.2 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.

2.3 a. 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.)

b. This project has potential emissions increases which are more than 100 tons/year of carbon monoxide (CO). The project is therefore subject to PSD review as a major modification for CO emissions. (See Attachment 3.)

2.4 a. 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.

b. i. 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.

ii. 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.

2.5 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.

2.6 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.

2.7 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 OVERALL SOURCE CONDITIONS

3.1 Project Description

The CORE project entails various changes to the refinery to increase both the total crude processing and the percentage of heavier crude at 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 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;
- Restart the Distilling West (formerly Premcor) Catalytic Cracking Unit (FCCU 3) and associated equipment (acquired as part of the Hartford Integration project) to allow for the processing of the additional gas oil (note that FCCU 3 will be permitted as a new unit);
- 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;
- Modifications to the wastewater treatment plant.

The key elements discussed above and other changes made to the refinery as part of this project are further addressed in unit-specific conditions (see Section 4.1 through 4.11). In addition, as explained in Finding 2.1(b), this permit also accounts for the emissions increases related to the CORE Project occurring at the Wood River Wood River Products Terminal (ID: 119050AAN), as addressed by Construction Permit 06110049.

3.2 Source-Wide 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 ConocoPhillips' Wood River Products 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).

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 Limits

The Permittee is subject to certain requirements in the Consent Decree United States of America and the States of Illinois, Louisiana and New Jersey, Commonwealth of Pennsylvania and the Northwest Clean Air Agency v. ConocoPhillips Company; Civil Action No. H-05-0258, entered by the District Court for the Southern District of Texas on January 27, 2005 (Consent Decree).

a. Pursuant to Paragraph 123 of the Consent Decree, the Permittee shall either eliminate, control, and/or include and monitor as part of a Covered SRP’s emissions under 40 CFR 60.104(a)(2), all sulfur pit emissions. “Control” for purposes of this Paragraph includes routing sulfur pit emissions into a contactor box of a Beavon Stretford TGU evaporator.

b. Pursuant to Paragraph 113 of the Consent Decree, Section G.: “SO2 Emission Reductions from and NSPS Applicability to Heaters and Boilers”, as of January 1, 2006, all heaters and boilers (except Distilling West) are affected facilities, as that term is used in the NSPS, 40 CFR Part 60, and are subject to and shall comply with the requirements of the NSPS Subparts A and J for fuel gas combustion devices.

3.2.5 Compliance Schedules

All alleged non-compliance (with applicable state and federal air pollution control requirements) posed by the major stationary sources in Illinois that are owned, operated, or under the same common control as the Permittee are addressed in the Consent Decree.

3.3 <u>Source-Wide Non-Applicability of Regulations of Concern</u>

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, PM_{10}, $PM_{2.5}$, and SO_2 emissions (See also Attachments 1 through 8).

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 97.9 tons/year (Refer to Condition 4.4.6(a)(ii)).

3.3.2 National Emission Standards For Hazardous Air Pollutants

a. The existing affected heaters are considered existing large gaseous fuel unit; therefore, the existing affected heaters are subject to only the initial notification requirements in 40 CFR 63.9(b) (i.e., they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of Subpart DDDDD or any other requirements in 40 CFR Part 63, Subpart A).

3.4 <u>Source-Wide Production and Emission Limitations</u>

3.4.1 Debottlenecked Heaters

a. The maximum design firing rate of the following existing heaters, which will be “debottlenecked” (i.e., experience an increased firing rate as a result of the CORE project) shall not exceed the following:

<table>
<tr><th>Heater</th><th>Firing Rate*
(mmBtu/hr)</th></tr>
<tr><td>DU-2 Lube Crude Heater, F-200</td><td>151</td></tr>
<tr><td>ULD2 H-1 Process Heater</td><td>32</td></tr>
<tr><td>HCF Heater</td><td>89.1</td></tr>
<tr><td>HDU-2 Charge Heater</td><td>81</td></tr>
<tr><td>CR-2 North Heater</td><td>137.5</td></tr>
<tr><td>CR-2 South Heater</td><td>137.5</td></tr>
<tr><td>CR-3 Charge Heater, H-4</td><td rowspan="3">420
(combined
limit)</td></tr>
<tr><td>CR-3 1st Reheat Heater, H-5</td></tr>
<tr><td>CR-3 2nd Reheat Heater, H-6</td></tr>
</table>

* 12-month rolling average, HHV

b. Emissions from the following heaters shall not exceed the following limits:

Heater	NO_x (Ton/Yr)	PM_{10} (Ton/Yr)	VOM (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
CR-2 N. Htr	165.3	4.5	3.2
CR-2 S. Htr	165.3	4.5	3.2
CR-3 H-4	439.3 (combined limit)	13.7 (combined limit)	9.9 (combined limit)
CR-3 H-5			
CR-3 H-6			

c. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

3.4.2 Debottlenecked Cooling Water Towers

a. i. The total capacity of existing cooling water towers CWT-3 and CWT-15, which will be debottlenecked (i.e., experience an increase in water circulation rate as a result of the CORE project) expressed in terms of design circulation rate, shall not exceed 35,000 gallons per minute (12-month rolling average).

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 2,000 ppm, on an annual average basis.

b. Emissions from the debottlenecked cooling water towers 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-3	0.89	7.1	0.01	0.1
CWT-15	0.26	2.1	0.01	0.1

3.4.3 Debottlenecked Flares

a. Emissions from the following existing flares, which will be debottlenecked (i.e., experience an increase in gas flow to the flare) shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data.

Emission Unit	Emissions (Tons/Year)	
	NO_x	VOM
WWTP VOC Flare #1	5.4	5.0
WWTP VOC Flare #2	5.4	5.0

Note: Debottlenecked units are the units that have not been modified but experience an increase in their effective capacity due to the removal of capacity limitations on an associated unit.

3.4.4 New Hydrogen Plant

a. The total emissions from the new Hydrogen Plant (HP2), including the reformer furnace (HP2 H-1), flare (HP2F), cooling tower (CWT 24), and fugitive emissions from leaking components, 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	125.6	23.3	45.6

3.5 Plant-Wide 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 Non-Attainment 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 Non-Attainment Area Pollutants From Debottlenecked Units

a. Boilers/Heaters

i. A file showing documentation of the maximum rated firing rate of each heater (mmBtu/hr, HHV).

ii. A file showing the potential NOx, VOM, and PM10 emissions from each heater with supporting calculations and documentation (tons/year).

b. Cooling Water Towers

i. Cooling water capacity of each cooling water tower, expressed in terms of design circulation rate (gallons/minute).

ii. Emissions of VOM and PM10 from each cooling water tower (tons/month and tons/year).

c. Flares

i. A file showing the potential NOx and VOM emissions from each flare with supporting calculations and documentation (tons/year).

3.6 Plant-Wide 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 Operate

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, the Alky HM-2 process heater will be altered by derating the maximum firing rate of this furnace to 99 mmBtu/hr. Ultra-low NO_x burners will also be installed on this modified heater.

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

a. An “affected heater” for the purpose of these unit-specific conditions, is a heater described in Conditions 4.1.1 and 4.1.2.

b. The affected heaters are subject to the NSPS for Petroleum Refineries, 40 CFR 60 Subparts A and J. The Permittee shall comply with all applicable requirements of 40 CFR Part 60 Subparts A and J.

   i. The Permittee shall not burn in the affected heaters 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. The affected heaters are subject to National Emission Standards for Hazardous Air Pollutants For Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD. The Permittee shall comply with all applicable requirements of 40 CFR Part 63 Subpart DDDDD.

   i. Pursuant to 40 CFR 63.7500(a)(1) and 63.7505(a), CO emissions from the new affected heaters shall not exceed 400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average), except during periods of startup, shutdown, and malfunction.

   Note: The altered affected heater (Alky HM-2) is considered an existing large gaseous fuel unit under the rule, and is subject to only the initial notification requirements in 40 CFR 63.9(b) (i.e., the heater is not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this rule or any other requirements in 40 CFR 63, Subpart A).

d. 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].

4.1.4 Non-Applicability of Regulations of Concern

None.

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.

iii. LAER Emission Limit

Emissions of VOM from the affected heaters shall not exceed 0.003 lb/mmBtu, HHV.

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. i. Pursuant to 40 CFR 63.7505(b), the Permittee shall always operate and maintain the new affected heaters, including air pollution control and monitoring equipment, according to the provisions in 40 CFR 63.6(e)(1)(i).

ii. Pursuant to 40 CFR 63.7505(e), the Permittee shall develop and implement a written SSMP according to the provisions in 40 CFR 63.6(e)(3), for the new affected heaters.

4.1.6 Production and Emission Limitations

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

Heater	Firing Rate* (mmBtu/hour)
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:

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	59.0	13.1
DCU2 H351H1	57.8	28.9	4.3	32.3	10.8
DCU2 H351H2	57.8	28.9	4.3	32.3	10.8
DCNH H-1	3.5	1.8	0.3	2.0	0.7
ULD2 H-2	9.6	4.8	0.7	5.4	1.8
Alky HM-2	17.3	8.7	1.3	9.7	3.2
BEU H3	43.8	21.9	3.3	24.5	8.2
HP2 H-1	240.1	111.7	16.8	125.0	41.6

c. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

4.1.7 Testing Requirements

a. Nitrogen Oxides Testing

i. Within 60 days after achieving the maximum production rate at which the affected heaters 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

b. Carbon Monoxide Testing For New Affected Heaters

i. Pursuant to 40 CFR 63.7510(g), the Permittee shall demonstrate initial compliance with the CO emission limit no later than 180 days after startup of each new affected heater.

A. The Permittee shall use the applicable performance tests and procedures in 40 CFR 63.7520 and 63.7530.

B. Pursuant to 40 CFR 63.7510(c), the initial compliance demonstration is:

1.----For new affected heaters in any of the limited use subcategories or with a heat input capacity less than 100 mmBtu per hour, the initial compliance demonstration shall be conducting a performance test for carbon monoxide according to Table 5 to 40 CFR 63, Subpart DDDDD.

2.----For new affected heaters in any of the large subcategories and with a heat input capacity of 100 mmBtu per hour or greater, the initial compliance demonstration shall be conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to 40 CFR 63.7525(a).

ii. Pursuant to 40 CFR 63.7515(e), the Permittee shall conduct all applicable performance tests according to 40 CFR 63.7520 on an annual basis. Annual performance tests must be completed between 10 and 12 months after the previous performance test.

c. Hydrogen Sulfide Testing

In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the affected heaters will be operated, but not later than 180 days after initial startup of the affected 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).

Note: The hydrogen sulfide testing requirement is not required if the H_2S content of the fuel gas to the affected heater is monitored by an existing CEM.

4.1.8 Monitoring Requirements

a. i. Pursuant to 40 CFR 63.7525(a), the Permittee shall install, calibrate, maintain and operate a continuous emissions monitoring system (CEMS) according to the procedures in 40 CFR 63.7525(a)(1) through (6) for emissions of CO from new affected heaters with a heat input capacity of 100 mmBtu per hour or greater.

ii. The Permittee shall demonstrate continuous compliance by following the continuous compliance requirements of 40 CFR 63.7535 and 63.7540.

b. Pursuant to 40 CFR 63.7505(d), the Permittee shall develop a site-specific monitoring plan according to the requirements in 40 CFR 63.7505(d)(1) through (4) for the new affected heaters.

c. The Permittee shall comply with the applicable monitoring requirements specified in 40 CFR 60.105 by one of the following methods:

i. 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 affected heaters, or

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

iii. 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.

d. The Permittee shall maintain records of the concentration (dry basis) of H2S in fuel gases before being burned in the affected heaters (or SO2 emissions to the atmosphere, if monitoring is performed according to Condition 4.1.8(c)(ii)) to demonstrate compliance with Condition 4.1.3(b)(i).

Note: Pursuant to 40 CFR 60.105(a)(3)(ii), the SO_2 monitoring level equivalent to the H_2S standard under 40 CFR 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

4.1.9 Recordkeeping Requirements

a. The Permittee shall maintain records of the following items for the affected heaters:

i. Firing rate of the affected heaters (mmBtu/hr, HHV on a 12 month rolling average).

ii. Heat content of the fuel gas (Btu/scf).

iii. NOx, CO, VOM, SO2, PM and PM10 emissions from the affected heaters (tons/month and tons/year).

b. The Permittee shall comply with the applicable recordkeeping requirements in 40 CFR 63.7555 for the new affected heaters.

4.1.10 Reporting Requirements

a. The Permittee shall promptly 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).

i. Emissions from the affected heaters in excess of the limits specified in Condition 4.1.6 within 30 days of such occurrence.

ii. Operation of the affected heaters in excess of the limits specified in Condition 4.1.6 within 30 days of such occurrence.

b. Pursuant to 40 CFR 63.7515(g), the Permittee shall report the results of performance tests within 60 days after the completion of the performance tests for the new affected heaters. This report should also verify that the operating limits for affected heaters have not changed or provide documentation of revised operating parameters established according to 40 CFR 63.7530 and Table 7 to 40 CFR Part 63 Subpart DDDDD, as applicable. The reports for all subsequent performance tests should include all applicable information required in 40 CFR 63.7550.

c. The Permittee shall comply with the applicable notification and recordkeeping requirements in 40 CFR 63.7545 and 63.7550, respectively for the new affected heaters.

d. The existing affected heater Alky HM-2 shall comply with the initial notification requirements in 40 CFR 63.9(b).

e. The Permittee shall comply with the applicable reporting requirements specified in 40 CFR 60.107(e) and (f) and 40 CFR 60.105(e)(3).

4.2 Distilling West (DW) Cracked Gas Plant

4.2.1 Description

Overhead from the DW CCU (FCCU 3) Main Fractionator will be routed to the existing DW cracked gas plant. Certain compounds from this plant must be sent to a treatment system which uses caustic. Off-gas from the DW caustic regeneration system will be routed to a new DW caustic regenerator thermal oxidizer.

Emissions from this cracked gas plant come from fugitive components and the new DW caustic regenerator thermal oxidizer. The fugitive components are addressed in section 4.3 of this permit. The remainder of this section addresses the thermal oxidizer.

4.2.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
DW Cracked Gas Plant	DW Cracked Gas Plant, including vent to caustic regenerator system from which off-gases are vented to the new thermal oxidizer	New Thermal Oxidizer

4.2.3 Applicable Provisions and Regulations

a. An “affected unit” for the purpose of these unit-specific conditions, is the new thermal oxidizer described in Conditions 4.2.1 and 4.2.2.

b. The affected unit is subject to the NSPS for Petroleum Refineries, 40 CFR 60 Subparts A and J. The Permittee shall comply with all applicable requirements of 40 CFR Part 60 Subparts A and J. The affected unit is considered a fuel gas combustion device under this rule.

   i. The Permittee shall not burn in the affected unit 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 the affected unit that is equivalent to the 230 mg/dscm H_2S fuel limit is 20 ppm SO_2 (dry basis, zero percent excess air).

4.2.4 Non-Applicability of Regulations of Concern

Non-applicability of regulations of concern are not set for the affected units.

4.2.5 Control Requirements and Work Practices

a. i. BACT/LAER Technology

The 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 the affected unit shall not exceed 0.082 lb/mmBtu, HHV.

iii. LAER Emission Limit

Emissions of VOM from the affected unit shall not exceed 0.005 lb/mmBtu, HHV.

Condition 4.2.5(a)(i) and (ii) represents the application of the Best Available Control Technology. Condition 4.2.5(a)(i) and (iii) represents the application of the Lowest Achievable Emission Rate.

b. 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 unit.

4.2.6 Production and Emission Limitations

a. The maximum design firing rate of the affected unit shall not exceed 12.63 mmBtu/hr (12-month rolling average, HHV).

b. Emissions from the affected unit shall not exceed the following limits:

Pollutant	Emissions (Tons/Month)	Emissions (Tons/Year)
NO_x	0.5	5.4
CO	0.4	4.6
SO_2	0.2	1.9
$PM/PM_{10}/PM_{2.5}$	0.1	0.4
VOM	0.1	0.3

c. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

4.2.7 Testing Requirements

a. Hydrogen Sulfide Testing

In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the affected unit will be operated, but not later than 180 days after initial startup of the affected unit 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).

Note: The hydrogen sulfide testing requirement is not necessary if the H_2S content of the fuel gas to the affected unit is monitored by an existing CEM.

4.2.8 Monitoring Requirements

a. The Permittee shall comply with the applicable monitoring requirements specified in 40 CFR 60.105 by one of the following methods:

   i. Installing, calibrating, maintaining and operating an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in the affected unit, or

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

   iii. 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.

b. The Permittee shall maintain records of the concentration (dry basis) of H2S in fuel gases before being burned in the affected unit (or SO2 emissions to the atmosphere, if monitoring is performed according to Condition 4.2.8(a)(ii)) to demonstrate compliance with Condition 4.2.3(b)(i).

   Note: Pursuant to 40 CFR 60.105(a)(3)(ii), the SO_2 monitoring level equivalent to the H_2S standard under 40 CFR 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

4.2.9 Recordkeeping Requirements

a. The Permittee shall maintain records of the following items for the affected unit:

   i. Firing rate of the affected unit (mmBtu/hr, HHV on a 12 month rolling average).

   ii. Heat content of the fuel gas (Btu/scf).

iii. NO_x, CO, VOM, SO_2, PM and PM_{10} emissions from the affected unit (tons/month and tons/year).

4.2.10 Reporting Requirements

a. The Permittee shall promptly notify the Illinois EPA of deviations of an affected unit with the permit requirements of this section (Section 4.2). Reports shall include information specified in Conditions 4.2.10(a)(i) and (ii).

   i. Emissions from the affected unit in excess of the limits specified in Condition 4.2.6 within 30 days of such occurrence.

   ii. Operation of the affected unit in excess of the limit specified in Condition 4.2.6 within 30 days of such occurrence.

b. The Permittee shall comply with the applicable reporting requirements specified in 40 CFR 60.107(e) and (f) and 40 CFR 60.105(e)(3).

4.3 Components

4.3.1 Description

As part of the piping and pumping equipment associated with 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)	None

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. This permit is issued based upon certain affected components being subject to National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, 40 CFR 63, Subparts A and CC. The Illinois EPA administers the NESHAP for subject sources in Illinois pursuant to a delegation agreement with the USEPA. The Permittee shall comply with all applicable requirements of 40 CFR 63, Subparts A and CC.

   Note: The refinery has indicated that it generally complies with the equipment leak requirements specified in 40 CFR 63, Subpart CC by complying with the Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry 40 CFR 60, Subpart VV.

c. This permit is issued based upon certain affected components being subject to Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, 40 CFR 60, Subparts A and GGG. The Illinois EPA administers the NSPS for subject sources in Illinois pursuant to a delegation agreement with the USEPA. The Permittee shall comply with all applicable requirements of 40 CFR 60, Subparts A and GGG.

   Note: The refinery has indicated that it generally complies with the equipment leak requirements specified in 40 CFR 60, Subpart GGG by complying with the Standards of Performance for Equipment Leaks of VOC in the Synthetic

Organic Chemicals Manufacturing Industry 40 CFR 60, Subpart VV.

d. 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 Part 63 Subpart CC, or 40 CFR 60 Subpart GGG are more stringent than the LDAR requirements in 35 IAC 219.445-452, compliance with 40 CFR Part 63 Subpart CC or 40 CFR 60 Subpart GGG for the applicable component shall be deemed compliance with 35 IAC 219.445-452.

4.3.4 Non-Applicability of Regulations of Concern

a. Pursuant to 40 CFR 63.640(p), components that would be also subject to the provisions of 40 CFR Parts 60 and 61 are required only to comply with the provisions of 40 CFR Part 63 Subpart CC, rather than Parts 60 and 61.

4.3.5 Control Requirements and Work Practices

a. LAER Technology

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 in heavy liquid service, shall comply with the standards for pumps, valves, and connectors in heavy liquid service in 40 CFR 63.169.

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.

Condition 4.3.5(a) represents the application of the Lowest Achievable Emission rate.

4.3.6 Production and Emission Limitations

a. Emissions of VOM from the affected components shall not exceed 45.8 tons per year. Compliance with this limit shall be determined using published USEPA methodology for determining VOM emissions from leaking components.

4.3.7 Testing Requirements

a. The Permittee shall comply with the applicable Test Methods and Procedures of 40 CFR 60.485.

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 purposes of 35 IAC 219.447(a)(1), unless the leaking components cannot be repaired until the unit is shut down 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. i. The Permittee shall comply with the recordkeeping requirements of 40 CFR 60.486.

ii. The Permittee shall maintain the records required by 40 CFR 60.486 for a minimum of 5 years, pursuant to 40 CFR 63.648(h).

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. Calculated VOM emissions, including supporting calculations, attributable to these components (tons/year).

4.3.10 Reporting Requirements

a. The Permittee shall promptly 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. The Permittee shall comply with the applicable Reporting requirements of 40 CFR 60.487.

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.

- Two new crude oil tanks (Tanks A-98 and A-99) will be installed to handle additional crude throughput to the refinery resulting from the start-up of the DU-2 LC. Each tank will have an internal floating roof.

- Tank 80-6 will be modified 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 required 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 to the bioorganisms in the activated sludge ponds. This tank will be a fixed roof design.

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.

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
TK-A098	New crude oil storage tank; 11 million gallon capacity; internal floating roof.	Internal Floating Roof
TK-A099	New crude oil storage tank; 11 million gallon capacity; internal floating roof.	Internal Floating Roof

Emission Unit	Description	Emission Control Equipment
Tank 80-6	Modified sour water storage tank; 3.36 million gallon capacity; Installation of dome on external floating roof (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-A098, TK-A099, and 80-6 are subject to National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, 40 CFR 63, Subparts A and CC. The Illinois EPA administers the NESHAP for subject sources in Illinois pursuant to a delegation agreement with the USEPA. The Permittee shall comply with all applicable requirements of 40 CFR 63, Subparts A and CC.

Note: affected tank TK-A126 is considered a Group 2 storage vessel under this rule and has no control requirements. Affected tanks TK-A098, TK-A099, 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 National Emission Standards for Hazardous Air Pollutants For Organic Liquids Distribution, 40 CFR 63, Subparts A and EEEE. The Illinois EPA administers the NESHAP for subject sources in Illinois pursuant to a delegation agreement with the USEPA. The Permittee shall comply with all applicable requirements of 40 CFR 63, Subparts A and EEEE.

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

c. The affected tanks TK-A098, TK-A099, and 80-6 are subject to 40 CFR 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

d. The affected tanks are subject to 35 IAC Part 219, Subpart B: Organic Emissions From Storage and Loading Operations.

4.4.4 Non-Applicability of Regulations of Concern

a. i. This permit is issued based on the 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 m^3 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 vessels with a capacity of less than 75 m^3 (19,812.9 gallons) [40 CFR 60.110b(a)].

b. i. This permit is issued based on the affected tanks A-126, A-98, A-99, 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 the 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 the 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 the affected tanks A-98, A-99, and 80-6 not being subject to 35 IAC 219.123: Petroleum Liquid Storage Tanks, because the affected tanks A-98, A-99, and 80-6 are subject to 40 CFR 60 Subpart Kb [35 IAC 219.123(a)(5)].

4.4.5 <u>Control Requirements and Work Practices</u>

a. LAER Technology

i. Affected tanks A-98, A-99, 80-6 shall be controlled by an internal floating roof (i.e., domed external floating roof for tank 80-6) with a primary liquid-mounted seal consistent with the control requirements of the 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 the 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.

Condition 4.4.5(a) represents the application of the Lowest Achievable Emission rate.

b. NSPS Control Requirements: The affected tanks A-98, A-99, 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 the following closure device between the wall of the storage vessel and the edge of the internal floating roof:

A. A foam-or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam-or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank [40 CFR 60.112b(a)(1)(ii)(A)].

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 A-98, A-99, 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 <u>Production and Emission Limitations</u>

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

	Throughput		VOM Emissions	
Tank	(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

ii. Breathing loss emissions of the following affected tanks shall not exceed the following limits:

	VOM Emissions	
Tank	(Ton/Mo)	(Ton/Yr)
A-98	0.08	0.5
A-99	0.08	0.5

Note: The working losses from affected tanks A-98 and A-99 are addressed by Condition 3.3.1, which includes both new and existing crude oil storage tanks.

iii. Emissions of the following affected tank shall not exceed the following limits:

	VOM Emissions	
Tank	(Ton/Mo)	(Ton/Yr)
80-6	0.07	0.4

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 fulfill all applicable testing and procedures requirements of 40 CFR 60.113b(a) for the affected tanks A-98, A-99, 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 Administrator [40 CFR 63.640(n)(8)(iii)].

b. The Permittee shall fulfill all applicable monitoring of operations requirements of 40 CFR 60.116b for the affected tanks A-98, A-99, 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).

iii. VOM emissions from each affected tank (tons/month and tons/year).

b. The Permittee shall fulfill all applicable recordkeeping requirements of 40 CFR 60.115b for the affected tanks A-98, A-99, and 80-6 [40 CFR 60.115b].

c. The Permittee shall fulfill all applicable recordkeeping requirements of 40 CFR 63.654 for the affected tanks TK-A126, TK-A098, TK-A099, 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 this subpart. 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 promptly 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).

    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 limit specified in Condition 4.4.6 within 30 days of such occurrence.

b. The Permittee shall fulfill all applicable reporting requirements specified in 40 CFR 60.115b for the affected tanks A-98, A-99, and 80-6 [40 CFR 60.115b].

    i. Owners and operators of storage vessels complying with Subpart Kb of Part 60 may submit the inspection reports required by 40 CFR 60.115b(b)(4) as part of the periodic reports required by 40 CFR Part 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 fulfill all applicable reporting requirements of 40 CFR 63.654 for the affected tanks TK-A126, TK-A098, TK-A099, and 80-6.

e. The Permittee shall comply with the 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 3 is considered a complete combustion unit (high temperature, full burn). High temperature regeneration, or full combustion regeneration uses excess oxygen and high operation temperatures to reduce the carbon deposits (i.e., coke) on the FCCU catalyst and to complete combustion of CO. No CO heater is used on FCCU 3 because CO concentrations in the high temperature regenerator effluent are relatively low. To maintain low concentrations of CO, FCCU 3 will be equipped with a system to inject a combustion promoter (catalyst) which would act to raise the operating temperature in the regenerator.

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 SO_2 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.

FCCU 3 was previously operated by Premcor and has been idle since 2002. As part of the CORE project, FCCU 3 will be restarted and permitted as a new unit, as required by a Consent Decree. This project includes the installation of a WGS to control particulate matter and sulfur dioxide emissions in the regenerator. The WGS will control SO_2 and will supplement the existing cyclones used to control particulate matter. SCR will be installed on the exhaust from the regenerator to control emissions of NO_x.

4.5.2 <u>List of Emission Units and Air Pollution Control Equipment</u>

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
FCCU 3	Restart of Fluidized Catalytic Cracking Unit (full combustion unit)	SCR, WGS, Cyclones, Flare

4.5.3 <u>Applicable Provisions and Regulations</u>

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 Provisions

The affected units are subject to the NSPS for Petroleum Refineries, 40 CFR Part 60, Subpart J. The Permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart J.

i. The affected units are subject to 40 CFR 60.102: Standard for particulate matter, which provides that no owner or operator shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

A. Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator [40 CFR 60.102(a)(1)].

B. Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period [40 CFR 60.102(a)(2)].

ii. The affected units are subject to 40 CFR 60.103: Standard for carbon monoxide, which provides that no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis) [40 CFR 60.103(a)].

iii. The affected units are subject to 40 CFR 60.104: Standards for sulfur oxides, which provides that with an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (vppm), whichever is less stringent [40 CFR 60.104(b)(1)]; or

Note: This permit does not address other alternative SO_2 emission standards in Subpart J, which rely on processing of very low-sulfur content material by FCCU, rather than use of an add-on control device.

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. Consent Decree Provisions

The affected units are subject to certain requirements in the Consent Decree United States of America and the States of Illinois, Louisiana and New Jersey, Commonwealth of Pennsylvania and the Northwest Clean Air Agency v. ConocoPhillips Company; Civil Action No. H-05-0258, entered by the District Court for the Southern District of Texas on January 27, 2005 (Consent Decree).

e. 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. SO_2 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 an three-hour block average basis.

Note: Condition 4.5.3(e)(ii)(B) applies to FCCU 1 and FCCU 2 only.

iii. CO Standards

A. The affected units FCCU 1 and FCCU 2, 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.

B. The affected unit FCCU 3, is subject to 35 IAC 216.361(c), which provides that the emission of a carbon monoxide waste stream into the atmosphere from any new 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 350 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 Non-Applicability 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 FCCUs 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

A. The affected units FCCU 1 and FCCU 2 shall be controlled by venting emissions to a CO heater or other combustion device.

B. The affected unit FCCU 3 shall utilize high temperature regeneration, i.e., full combustion, supplemented with CO promoter as needed to comply with the applicable hourly limit.

ii. BACT Emission Limit

A. Emissions of CO from affected units FCCU 1 and FCCU 2 shall not exceed:

1.----100 ppmdv corrected to 0 percent oxygen on a 365 day rolling average; and

2.----500 ppmdv corrected to 0 percent oxygen on an hourly average basis.

B. Emissions of CO from FCCU 3 shall not exceed:

1.----150 ppmdv corrected to 0 percent oxygen on a 365 day rolling average; and

2.----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

A. Emissions of VOM from FCCU 1 and FCCU 2 shall not exceed 0.05 lb/1000 lb of coke burned.

B. Emissions of VOM from FCCU 3 shall not exceed 11 lb/1000 bbl of feed.

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

c. i. Pursuant to Paragraph 60 and 81 of the Consent Decree, the Permittee shall install and operate a wet gas scrubber on the affected unit FCCU 3.

ii. This permit authorizes the Permittee to install and operate a wet gas scrubber on affected units FCCU 1 and FCCU 2.

iii. 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)].

4.5.6 Production and Emission Limitations

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).

iii. The daily average coke burn rate of FCCU 3 shall not exceed 300 tons (12-month rolling average).

b. i. A. SO_2 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% O_2, pursuant to 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, pursuant to Paragraphs 77 and 81 of the Consent Decree.

C. NO_x concentrations from the affected units FCCU 1 and FCCU 2 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% O_2, pursuant to 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:

	Emissions (Tons/Year)				
Unit	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
FCCU 3	189.8	41.6	72.4	54.8	60.2

4.5.7 Testing Requirements

a. i. Within 60 days after achieving the maximum production rate at which the affected units will be operated, but not later than 180 days after initial startup of the affected units and at such other times as may be required by the USEPA under Section 114 of the Act, the owner or operator shall conduct performance test(s) and furnish the Illinois EPA and USEPA a written report of the results of such performance test(s) [40 CFR 60.8(a)].

ii. 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.

b. i. The method and procedures specified by the NSPS, 40 CFR 60.106 and 60.108, shall be used for testing of PM, CO and SO_2 emissions and opacity, unless USEPA approves an alternative test method pursuant to 40 CFR 60.8.

ii. The following methods and procedures shall be used for testing of NOx and VOM 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 7
Volatile Organic Material	USEPA Method 25A

The Reference Method listed above refers to the base method or any of its “sub-methods”, e.g., Method 2 includes Methods 2, 2A, 2B, 2C, and 2D; Method 3 includes Methods 3 and 3A; and Method 7 includes Methods 7, 7A, 7B, 7C, 7D, and 7E.

c. Pursuant to Paragraph 83 of the Consent Decree, the test methods specified in 40 CFR 60.106(b)(2) shall be used to measure the PM emissions from the affected unit FCCU 3. This test shall be performed no later than 6 months after initial startup of the affected unit FCCU 3 and annually thereafter.

4.5.8 Monitoring Requirements

a. Consent Decree Monitoring Requirements

Pursuant to Paragraph 54, 60, 73, and 86 of the Consent Decree, the Permittee shall use SO_2, NO_x, CO, and O_2 CEMS to monitor the performance of the affected units.

b. NSPS Monitoring Requirements

i. The Permittee shall comply with the applicable monitoring of emissions and operations requirements identified in 40 CFR 60.105 for the affected units. In particular, opacity, CO, and SO2 continuous monitoring systems shall be installed, calibrated, maintained and operated for the affected units, pursuant to 40 CFR 60.105.

ii. 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.

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 system 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 system 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 <u>Recordkeeping Requirements</u>

a. The Permittee shall comply with the applicable recordkeeping requirements identified in 40 CFR 60.107 for the affected units.

b. The Permittee shall comply with the applicable recordkeeping requirements identified in 40 CFR 63.1576 for the affected units.

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, NOx, SO2, PM/PM10 and VOM (tons/month and tons/year) with supporting documentation.

4.5.10 Reporting Requirements

a. Reporting of Deviations

The Permittee shall promptly notify the Illinois EPA of deviations of an affected unit with the permit requirements of this section (Section 4.5). Reports shall include information specified in Conditions 4.5.10(a)(i) and (ii):

i. Emissions from the affected units in excess of the limits specified in Condition 4.5.6 within 30 days of such occurrence.

ii. Operation of the affected units in excess of the limits specified in Condition 4.5.6 within 30 days of such occurrence.

b. The Permittee shall comply with the applicable reporting requirements identified in 40 CFR 60.107 for the affected units.

c. The Permittee shall comply with the applicable notification requirements identified in 40 CFR 63.1574 for the affected units.

d. The Permittee shall comply with the applicable reporting requirements identified in 40 CFR 63.1575 for the affected units.

4.5.11 Operational Flexibility/Anticipated Operating Scenarios

Operational flexibility is not set for the affected units.

4.5.12 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 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 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 tower.

Several existing cooling towers will be debottlenecked as a result of this project. The associated emission increases 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
CW23	New North Property Cooling Water Tower	Drift Eliminators
CW24	New HP-2 Cooling Water Tower	Drift Eliminators
SRU CWT	New cooling water tower for the Sulfur Recovery Units.	Drift Eliminators

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) must comply with the heat exchanger system requirements of 40 CFR 63.104.

4.6.4 Non-Applicability of Regulations of Concern

a. The LDAR program of Condition 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.

4.6.5 Control Requirements and Work Practices

a. LAER Technology

i. The design drift loss from the drift eliminators on the affected units shall not exceed 0.006 percent (12-month rolling average).

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

4.6.6 Production and Emission Limitations

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)
CW23	50,000
CW24	15,000
SRU CWT	5,000

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 2,000 ppm on an annual average.

b. 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/PM_{10} Emissions		VOM Emissions	
	(Tons/Mo)	(Tons/Yr)	(Tons/Mo)	(Tons/Yr)
CW23	1.65	13.2	0.03	0.2
CW24	0.49	3.9	0.01	0.1
SRU CWT	0.16	1.3	0.01	0.1

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).

4.6.8 Inspection 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.

4.6.9 <u>Recordkeeping Requirements</u>

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 PM_{10}, with supporting calculations (tons/month and tons/year).

4.6.10 Reporting Requirements

The Permittee shall promptly 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 in Condition 4.6.10(b).

a. 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.

b. i. Emissions from the affected units in excess of the limits specified in Condition 4.6.6 within 30 days of such occurrence.

   ii. Operation of the affected units in excess of the limits specified in Condition 4.6.6 within 30 days of such occurrence.

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 new 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 from the new Delayed Coker Unit and the new Hydrogen Plant 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 SO_2.

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

4.7.3 Applicability Provisions and Regulations

a. i. An “affected unit” 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 or the new Hydrogen Plant, as described in Conditions 4.7.1 and 4.7.2.

b. The affected units are subject to New Source Performance Standards (NSPS) for Petroleum Refineries, 40 CFR Part 60, Subpart Ja. In addition to being regulated as flares, the affected units are also regulated as fuel gas combustion devices pursuant to this NSPS.

i. Each affected unit is subject to 40 CFR 60.102(g)(1), which provides that either;

A. The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0 percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0 percent excess air), determined daily on a 365 successive day rolling average basis; [40 CFR 60.102a(g)(1)(i)] or

B. 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. Each affected unit is subject to 40 CFR 60.102(g)(3), which provides that the owner or operator of an affected flare shall not allow flow to a subject flare during normal operations of more than 7,080 standard cubic meters per day (250,000 standard cubic feet per day on a 30-day rolling average.

iii. A. Notwithstanding the above conditions, pursuant to 40 CFR 60.102(h), the combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from the above requirements of 40 CFR 60.102a(g).

B. Notwithstanding the above conditions, in periods of fuel gas imbalance (as described in the Flare Management Plan required by 40 CFR 60.103a(a)), compliance with 40 CFR 60.102a(g)(3) shall be demonstrated by following the procedures and maintaining the records described in the Flare Management Plan to document the periods of excess fuel gas.

iv. Each affected unit is subject to 40 CFR 60.103a(a), which provides that the owner or operator of a flare shall develop and implement a written flare management plan, which plan must include the information and procedures specified by 40 CFR 60.103a(a)(1) through (a)(6).

v. Each affected unit is subject to 40 CFR 60.103a(b), which provides that the owner or operator of a fuel gas combustion device shall conduct a root cause analysis of any emission limit exceedance or process start- up, shutdown, upset, or malfunction that causes an SO2 discharge to the atmosphere in excess of 227 kilograms per day (500 lb per day) and shall keep records for each such root cause analysis performed, including the date and duration of the discharge, the results of the analysis, and the actions taken as a result of the analysis.

c. The affected units 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 units 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 Delayed Coker Unit is subject to the NSPS, 40 CFR 60.103a(b), which provides that the owner or operator of a delayed coking unit shall depressure to 5 lb per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system for combustion in a fuel gas combustion device.

4.7.4 <u>Non-Applicability of Regulations of Concern</u>

Non-applicability of regulations of concern are not set for the affected units.

4.7.5-1 <u>Control Requirements and Work Practices</u>

a. BACT/LAER Technology

i. The affected units 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 units shall be the following. This provision does not restrict the flow of air or steam or other noncombustible gases to the affected units.

A. Process upset gases (as defined in 40 CFR 60.101a(a)), 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. Except during malfunction, as defined by 40 CFR 63.2, depressurization of process vessels in the affected Delayed Coker Unit shall be conducted with exhaust gases recovered for use in the fuel gas system until the pressure in the vessel is no more than 5.0 lb per square inch gauge, before any exhaust gases are sent to be combusted in an affected unit.

Note: Turnarounds of the affected plants (i.e., the new Delayed Coker Unit and the new Hydrogen Plant) are subject to the requirements of 35 IAC 219.444, Process Unit Turnarounds.

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 system for the Delayed Coker Unit, 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 shall be determined in accordance with Attachment 9.2, Procedures for Calculating CO and VOM Emissions from New Flares.

vii. The total flow of pilot and purge gas to the affected units 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 unit 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 unit (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.

x. Each affected unit shall continue to comply with each applicable substantive requirement of the NSPS, 40 CFR 60 Subpart Ja, as adopted by USEPA on June 24, 2008 (73 FR 35838 et seq.), in the event that as a matter of federal law any such requirement is no longer in effect (e.g., the provision of the NSPS is stayed or remanded due to an appeal) or is replaced by a less stringent requirement. The Permittee shall also continue to comply with the associated compliance procedures (i.e., provisions for monitoring, recordkeeping, and reporting) in the NSPS associated with a substantive requirement that are relevant to verifying compliance with such requirement. Notwithstanding the above, under the circumstances addressed by this condition, the Illinois EPA may approve alternative compliance procedures as provided for under the NSPS, acting in place of USEPA. The Illinois EPA may also determine that a substantive requirement of the NSPS subsequently adopted by USEPA for an aspect of flare operation is equivalent to or provides for more stringent control of emissions than the requirement for that aspect of flare operation adopted on June 24, 2008, and that implementation of the earlier requirement, as well as the adopted requirement, would be inconsistent or impractical.

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 affected unit 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 9.2, 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 unit that would cause the SO_2 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 units 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 unit, including vent gas lines, knockout pots, surge drums, seal drums, and other significant components of the affected unit; and a description of the monitoring systems and process controls for the affected unit, 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 feed back 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 measured 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 nonoverlapping 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 SO_2 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 unit for the flaring incident under the NSPS or the Consent Decree. 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 Limitations

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 SO_2 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 unit other than emissions attributable to combustion of pilot and purge gas by the flare.

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

4.7.7 <u>Testing Requirements</u>

a. Upon request by the Illinois EPA, the Permittee shall have testing of an affected unit 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 higher 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.

4.7.8-1 Monitoring Requirements

a. The Permittee shall conduct continuous monitoring for each affected unit as required by the NSPS, 40 CFR 60.107a, including:

i. Monitoring for the SO_2 emissions or H_2S content of fuel gas sent to the unit pursuant to the applicable provisions of 40 CFR 60.107a(a)(1) or (2), except as fuel gas stream(s) are exempted from such monitoring pursuant to 40 CFR 60.107a(b).

ii. Monitoring for the concentration of reduced sulfur in the flare gas before being burned in accordance with the provisions of 40 CFR 60.107a(d).

iii. Monitoring for the exhaust gas flow rate to the unit, in standard cubic feet per minute (scfm) (i.e., corrected for temperature and pressure to provide data for exhaust gas flow rate at standard conditions as defined in 40 CFR 60.2), which system shall be operated according to the manufacturer's specifications and requirements, in accordance with 40 CFR 60.107a(e).

iv. Notwithstanding the above, the Permittee may also comply with alternative monitoring procedures pursuant to 40 CFR 60.13(i), if after receipt and consideration of written application, the USEPA approves such procedures for the affected unit(s).

b. In addition to complying with applicable requirements of the NSPS, the continuous monitoring system on each affected unit for the flow rate of the vent stream that is flared (as addressed by Condition 4.7.8(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 unit 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 unit 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 unit 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 unit.

e. The Permittee shall install, operate and maintain continuous monitoring systems on each affected unit 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 unit, 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 unit 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 unit or plant, with explanation, including:

A. Records of deviations from Condition 4.7.3(b)(i) with either: 1) The concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (SO_2 monitoring); or 2) The concentration (dry basis) of H_2S in fuel gases before being burned in the affected unit (H_2S monitoring).

B. Records of the date and duration of any time when there was no pilot flame present at an affected unit.

h. The Permittee shall develop and maintain written Monitoring Procedures for each affected unit 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 unit 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 location, 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 higher heating value of flares vent gas, as required by Condition 4.7.8-3.

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 unit 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 higher heating value of the vent gas, with records kept of the higher 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 unit, 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. H_2S 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 H_2S or TRS for the affected unit, 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. H_2S 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 4.7.8-3(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 H_2S for the affected unit as follow:

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 4.7.8-2(c)(v) and (vi).

4.7.8-3 <u>Visual Imaging and Observation Requirements</u>

a. i. The Permittee shall install, operate and maintain visual imaging equipment on each affected unit 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 unit, 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 unit, 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 unit 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 unit, 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 and each root cause analysis of a discharge required by the NSPS.

ii. For each fuel gas stream to which one of the exemptions listed in 40 CFR 60.107a(a)(3) applies, records of the specific exemption determined to apply for each fuel stream, pursuant to 40 CFR 60.108a(c)(5). If the Permittee applies for the exemption described in 40 CFR 60.107a(a)(3)(iv), the Permittee must keep a copy of the application as well as the letter from the USEPA granting approval of the application.

iii. Records of discharges greater than 500 lb/day SO_2 or in excess of 500,000 scf/day, which shall be accompanied by the information specified in 40 CFR 60.107a(c)(6)(i) through (vi), pursuant to 40 CFR 60.108a(c)(6).

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 unit, 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 unit, 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 unit, 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 SO_2*, 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, SO_2, and CO emissions from each affected unit (tons/month and tons/year), with supporting calculations.

iv. Records of the SO_2 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 SO_2 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 Permittee shall comply with the applicable notification and reporting requirements of the NSPS, 40 CFR 60.7 and 60.108a, for each affected unit, including:

i. Notification for the specific monitoring provisions of 40 CFR 60.105a, 60.106a, and 60.107a with which the Permittee seeks to comply, as provided by 40 CFR 60.108a(b).

ii. Submittal of excess emissions reports for certain NSPS requirements as provided by 40 CFR 60.7(c), 60.107a(f) and 60.108a(d).

b. The Permittee shall promptly notify the Illinois EPA of deviations of an affected unit or plant 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 units 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 SO_2 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 unit, 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 a 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 SO_2.

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 SO_2.

e. With its Annual Emission Report, the Permittee shall submit a report to the Illinois EPA for flaring by each affected unit during the previous year, which report shall:

i. The information specified in Condition 4.7.10(d)(i) for flaring events during the year.

ii. Summarize flaring activity and emissions during the previous year, including an assessment of the cause(s) for such flaring as related to the number of events and share of emissions, a summary of each event-specific Root Cause Analysis was performed, and calculated CO emissions of the unit as compared to the limit in Condition 4.7.5-2.

iii. Include copies of the summaries for flaring activity for the preceding three years, as reported in earlier reports, as these summaries become available.

iv. Provide an analysis of the amount of vented gas that was recovered as related 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 4.7.5-3(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 trains (SRU-E and SRU-F) will be constructed. Each SRU will have a separate Claus Unit, a 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 Regulations

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, 40 CFR Part 60, Subpart J.

i. Each affected unit is subject to 40 CFR 60.104(a)(2)(i), which provides that no owner or operator shall discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant (oxidation control system followed by incineration) containing in excess of 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air.

ii. The Permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart J for the affected units.

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 Part 63, Subpart UUU.

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

i. 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 <u>Non-Applicability of Regulations of Concern</u>

None.

4.8.5 <u>Control Requirements and Work Practices</u>

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 the affected units shall not exceed 0.082 lb/mmBtu, HHV.

ii. LAER Emission Limit

Emissions of VOM from each affected unit shall not exceed 0.005 lb/mmBtu, HHV.

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.

4.8.6 Production and Emission Limitations

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

Equipment	NO_x (Tons/Yr)	CO (Tons/Yr)	VOM (Tons/Yr)	SO_2 (Tons/Yr)	PM/PM_{10} (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 on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

4.8.7 Testing Requirements

a. Within 60 days after achieving the maximum production rate at which each affected units will be operated, but not later than 180 days after initial startup of the affected units and at such other times as may be required by the USEPA under Section 114 of the Act, the Permittee shall conduct performance test(s) and furnish the Illinois EPA and USEPA a written report of the results of such performance test(s) [40 CFR 60.8(a)].

b. i. The method and procedures specified by the NSPS, 40 CFR 60.106 and 60.108, shall be used for testing of SO_2 emissions and opacity, unless USEPA approves an alternative test method pursuant to 40 CFR 60.8.

ii. Appropriate USEPA Reference Methods in 40 CFR Appendix A shall be used for testing of NO_x and CO emissions.

4.8.8 Monitoring Requirements

a. The Permittee shall comply with the monitoring requirements specified in 40 CFR 60.105 for the affected units by installing, calibrating, maintaining and operating the following continuous monitoring system:

i. An instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO2 emissions into the atmosphere.

The monitor shall include an oxygen monitor for correcting the data for excess air [40 CFR 60.105(a)(5)].

A. The span values for this monitor are 500 ppm SO_2 and 25 percent O_2 [40 CFR 60.105(a)(5)(i)].

B. The performance evaluations for this SO_2 monitor under 40 CFR 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations [40 CFR 60.105(a)(5)(ii)].

ii. Notwithstanding the above, the Permittee may also comply with alternative monitoring procedures pursuant to 40 CFR 60.13(i), if after receipt and consideration of written application, the USEPA approves such procedures for the affected units.

b. NESHAP Monitoring Requirements

i. The Permittee shall install, operate, and maintain a continuous monitoring system to measure and record the hourly average concentration of SO_2 (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, SO_2, and PM/PM_{10} (tons/month and tons/year).

4.8.10 Reporting Requirements

a. Reporting of Deviations

The Permittee shall promptly notify the Illinois EPA of deviations of an affected unit with the permit requirements of this section (Section 4.8). Reports shall include information specified in Condition 4.8.10(a)(i).

i. Within 30 days of exceedance of the limits in Condition 4.8.6.

b. The Permittee shall comply with the applicable reporting requirements specified in 40 CFR 60.107(e) and (f).

c. For the purpose of reports under 40 CFR 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows [40 CFR 60.105(e)]:

   i. All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under 40 CFR 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air) [40 CFR 60.105(e)(4)(i)]; or

   ii. All 12-hour periods during which the average concentration of reduced sulfur (as SO_2) as measured by the reduced sulfur continuous monitoring system under 40 CFR 60.105(a)(6) exceeds 300 ppm [40 CFR 60.105(e)(4)(ii)]; or

   iii. All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under 40 CFR60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air) [40 CFR 60.105(e)(4)(iii)].

d. 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

Additional catalyst loading operations will be needed due to the restart of FCCU 3. These emissions are fugitive in nature consisting entirely of particulates. Catalyst hopper vents will be routed to the WGS at FCCU 3.

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
FCCU 3 Catalyst Loading	Catalyst Loading at FCCU 3	None
Coke Handling	Coke Handling	None

4.9.3 Applicable Provisions and Regulations

a. The “affected units” for the purpose of these unit-specific conditions, are the units described in Conditions 4.9.1 and 4.9.2.

   i. The affected units are subject to 35 IAC 212.301 and 35 IAC 212.123 (See also Condition 3.2.2(a) and (b)).

4.9.4 Non-Applicability of Regulations of Concern

Non-applicability of regulations of concern are not set for the affected units.

4.9.5 Control Requirements and Work Practices

Control requirements and work practices are not set for the affected units.

4.9.6 Production and Emission Limitations

a. i. The maximum catalyst loading rate at FCCU 3 shall not exceed 10 tons/day (12-month rolling average).

   ii. Emissions from the affected catalyst loading operation at FCCU 3 shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data:

Pollutant	Emissions	
	(Tons/Month)	(Tons/Year)
PM	0.2	1.1
PM_{10}	0.2	0.3

b. i. The maximum coke processed shall not exceed 5,400 dry tons/day (12-month rolling average).

ii. Emissions from the affected coke handling operations shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data:

Pollutant	Emissions	
	(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 units.

4.9.8 Monitoring Requirements

Monitoring requirements are not set for the affected units.

4.9.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items:

a. Catalyst loading rate at FCCU 3 (tons/day).

b. Coke processed (dry tons/day).

c. PM and PM_{10} emissions (tons/month and tons/year) from the affected catalyst loading operation and the affected coke handling operation with supporting calculations and documentation.

4.9.10 Reporting Requirements

a. Reporting of Deviations

The Permittee shall promptly notify the Illinois EPA of deviations of an affected unit with the permit requirements of this section (Section 4.9). Reports shall include information specified in Condition 4.9.10(a)(i).

i. Within 30 days of exceedance of the limits in Condition 4.9.6.

4.10 Wastewater Treatment Plant

4.10.1 Description

The wastewater treatment plant (WWTP) will be modified to accommodate an increase in wastewater flow and solids and organic loading due to increased refining operations and to treat the wastewater from the new WGS on FCC Units. The modifications include new scrubber solids clarifiers, reconfiguring Pond 1 to activated sludge service, modifications to Pond 2 with a denitrification zone added to the back of the pond, and a new final clarifier. In addition, new process sumps will be installed to support the new and expanded process units.

Emissions from the existing primary treatment system, which are controlled by flares, are addressed in Section 3.4.3 (Debottlenecked Flares) of this permit.

4.10.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
WWTP	New scrubber solids clarifiers, reconfiguring Pond 1 to activated sludge service, modifications to Pond 2 with a denitrification zone added to the back of the pond, and a new final clarifier.	None
	New Final Clarifier (Secondary)	None

4.10.3 Applicable Provisions and Regulations

a. The “affected units” for the purpose of these unit-specific conditions, are the units described in Conditions 4.10.1 and 4.10.2.

b. Certain existing equipment associated with the affected units are subject to the following rules, as further described in the source’s CAAPP permit:

NESHAP for Benzene Waste Operations, 40 CFR 61 Subpart FF
NESHAP for Refineries, 40 CFR 63 Subpart CC
NSPS for Tanks, 40 CFR 60 Subpart Kb
NSPS for Refinery Wastewater Systems, 40 CFR 60 Subpart QQQ

4.10.4 Non-Applicability of Regulations of Concern

Non-applicability of regulations of concern are not set for the affected units.

4.10.5 Control Requirements and Work Practices

a. LAER Technology

   i. The WWTP shall be operated in accordance with good air pollution control practice to minimize emissions of VOM.

   Condition 4.10.5(a) represents the application of the Lowest Achievable Emission Rate. 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.

4.10.6 Production and Emission Limitations

a. VOM emission from the WWTP, in total, shall not exceed 8.5 tons/month and 84.7 tons/year.

b. VOM emissions from the new scrubber solids clarifiers shall not exceed 1.0 tons/year.

c. Compliance with the annual limits shall be determined from a running total of 12 months of data using Water 9 or other similar USEPA methodology for determination of VOM emission from wastewater treatment plants.

4.10.7 Testing Requirements

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

4.10.8 Monitoring Requirements

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

4.10.9 Recordkeeping Requirements

a. The Permittee shall comply with the applicable recordkeeping requirements at 40 CFR 61.356.

b. The Permittee shall maintain records of the following items:

   i. Throughput (millions gallons/day).

   ii. VOM emissions (tons/month and tons/year) from the affected units with supporting calculations and documentation.

4.10.10 Reporting Requirements

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

b. Reporting of Deviations

   The Permittee shall promptly notify the Illinois EPA of deviations of an affected unit with the permit requirements of this section (4.10). Reports shall include information specified in Condition 4.10.10(a)(i).

   i. Within 30 days of exceedance of the limits 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 wind blown 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 Dust Control Program

4.11.3 Applicable Provisions and Regulations

a. An “affected unit” 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. Not withstanding 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 (See also Condition 3.3.1).

4.11.4 Non-Applicability of Regulations of Concern

Non-applicability 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 Production and Emission Limitations

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 PM_{10}.

b. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

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 Overall Source 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 Overall Source 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 Condition 4.11.3(c), 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 promptly notify the Illinois EPA of deviations with permit requirements 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.

5.0 ATTACHMENTS

Attachment 1: Project Emission Summary

Table 1 – Project Emission Summary (Tons/Year)

Operation	NO_x (PSD)	NO_x (NAA NSR)	CO	SO_2	VOM	PM	$PM_{10}/PM_{2.5}$*
Refinery CORE Increases							
Heaters/Boilers	884.4	846.3	394.3	386.3	44.7	102.4	102.4
DW Thermal Oxidizer	5.4	5.4	4.6	1.9	0.3	0.4	0.4
Components	---	---	---	---	45.8	---	---
Tanks	---	---	---	---	105.3	---	---
FCCU's	41.6	41.6	485.2	72.4	68.3	54.8	54.8
Cooling Water Towers	---	---	---	---	0.4	27.6	27.6
Flares	15.1	15.1	75.1	189.2	13.7	---	---
Sulfur Recovery Units	36.8	36.8	43.3	437.4	2.8	3.9	3.9
Fugitive PM Emission Units	---	---	---	---	---	70.8	24.1
WWTP Secondary Treatment	---	---	---	---	44.4	---	---
Roadways & Other Open Areas	---	---	---	---	---	59.3	11.6
SUBTOTAL:	983.3	945.2	1,002.5	1,087.2	325.7	319.2	224.8
Terminal CORE Increases	9.5	9.5	23.8	---	54.0	10.0	1.9
SUBTOTAL:	992.8	954.7	1,026.3	1,087.2	379.7	329.2	226.7
Significance Threshold:	40	40	100	40	40	25	15
Greater Than Significant?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Refinery CORE Decreases	1,043.7	1,043.7	15.5	11,131.4	0.3	131.3	131.3
OVERALL PROJECT NET CHANGE:	- 50.9	- 89.0	1,010.8	-10,044.2	379.4	197.9	95.4

* Emissions of $PM_{2.5}$ in this table are expressed as emissions of PM_{10}, which is being used as a surrogate pollutant (see Condition 2.2).

Attachment 2a

PSD Applicability - NO_x Netting Analysis

Contemporaneous Time Period: July 2002 through October 2009

Table I – Project Emissions Increases and Decreases

Project/Activity	Emission Change (Tons/Year)
CORE Project	-47.5

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Project/Activity	Permit Number	Date	Emissions Increase (Tons/Year)
North Property Flare	06030049	6/2007	1.2
Low Sulfur Gasoline (SZU)	05050062	2/2007	20.6
Ultra Low Sulfur Diesel	04050026	4/2006	157.8
Hartford Integration	03080006	4/2004	524.2
Tier 2	01120044	11/2003	99.2
FCCU 1 Alterations (Boiler 17)	03030069	9/2003	1.8
		Total:	804.8

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Project/Activity	Date	Emissions Decrease (Tons/Year)
North Property Ground Flare Decommissioned	7/2007	1.5
RFP Shutdown	12/2002	2.6
CR-3 2nd Reheat Heater (fuel switch)	11/2002	86.7
CR-3 1st Reheat Heater (fuel switch)	11/2002	113.1
CR-3 Charge Heater (fuel switch)	11/2002	115.8
No. 2 Crude Unit, H-25	10/2002	29.7
Isom Unit, H-33 (Hartford Integration)	10/2002	2.5
Isom Unit, H-32 (Hartford Integration)	10/2002	10.8
LSR Hydrotreating, H-31 (Hartford Integration)	10/2002	1.7
Hydrogen Plant, H-30 (Hartford Integration)	10/2002	10.0
Alkylation Heater, H-19 (Hartford Integration)	10/2002	20.8
Reroute/Elimination of Flare Streams at Hartford	10/2002	17.4
FCCU Shutdown at Hartford	10/2002	320.0
	Total:	732.6

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With Proposed Modification	-47.5
Creditable Contemporaneous Emission Increases	804.8
Creditable Contemporaneous Emission Decreases	732.6
	24.7

Attachment 2b

Non-attainment NSR Applicability - NO_x Netting Analysis (8-hour Ozone)

Contemporaneous Time Period: May 2001 through October 2009

Table I – Project Emissions Increases and Decreases

Project/Activity	Emission Change (Tons/Year)
CORE Project	-85.6

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Project/Activity	Permit Number	Date	Emissions Increase (Tons/Year)
North Property Flare	06030049	6/2007	1.2
Low Sulfur Gasoline (SZU)	05050062	2/2007	20.6
Ultra Low Sulfur Diesel	04050026	4/2006	225.3
Hartford Integration	03080006	4/2004	524.2
Tier 2	01120044	11/2003	99.2
FCCU 1 Alterations (Boiler 17)	03030069	9/2003	1.8
RAU Steam Reboiler	01060090	10/2001	24.8
		Total:	897.1

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Project/Activity	Date	Emissions Decrease (Tons/Year)
North Property Ground Flare Decommissioned	7/2007	1.5
RFP Shutdown	12/2002	2.6
CR-3 2nd Reheat Heater (fuel switch)	11/2002	86.7
CR-3 1st Reheat Heater (fuel switch)	11/2002	113.1
CR-3 Charge Heater (fuel switch)	11/2002	115.8
No. 2 Crude Unit, H-25	10/2002	29.7
Isom Unit, H-33 (Hartford Integration)	10/2002	2.5
Isom Unit, H-32 (Hartford Integration)	10/2002	10.8
LSR Hydrotreating, H-31 (Hartford Integration)	10/2002	1.7
Hydrogen Plant, H-30 (Hartford Integration)	10/2002	10.0
Alkylation Heater, H-19 (Hartford Integration)	10/2002	20.8
Reroute/Elimination of Flare Streams at Hartford	10/2002	17.4
FCCU Shutdown at Hartford	10/2002	320.0
CR-1 2nd Inter-reactor Heater, H-3 (Fuel Switch)	2/2002	32.1
CR-1 1st Inter-reactor Heater, H-2 (Fuel Switch)	2/2002	19.1
CR-1 Feed Preheat, H-1 (Fuel Switch)	2/2002	19.5
RAU Deethanizer Heater Shutdown	10/2001	19.6
	Total:	822.9

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With Proposed Modification	-85.6
Creditable Contemporaneous Emission Increases	897.1
Creditable Contemporaneous Emission Decreases	822.9
	-11.4

Attachment 3

PSD Applicability - CO Netting Analysis

Contemporaneous Time Period: July 2002 through October 2009

Table I – Project Emissions Increases and Decreases

Project/Activity	Emission Change (Tons/Year)
CORE Project	1,047.4

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Project/Activity	Permit Number	Date	Emissions Increase (Tons/Year)
North Property Flare	06030049	6/2007	6.3
Low Sulfur Gasoline (SZU)	05050062	2/2007	40.6
Ultra Low Sulfur Diesel	04050026	4/2006	92.7
Tier 2	01120044	11/2003	70.7
FCCU 1 Alterations (Boiler 17)	03030069	9/2003	1.1
		Total:	211.4

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Project/Activity	Date	Emissions Decrease (Tons/Year)
HTR-VF1-North	12/2009	14.7
HTR-VF1-South	12/2009	16.5
HTR-BEU-HM1 Shutdown	12/2008	26.7
HTR-BEU-HM2 Shutdown	12/2008	18.8
Boiler 16 Shutdown	12/2008	81.7
North Property Ground Flare Decommissioned	7/2007	7.9
HTR-KHT	4/2006	32.5
RFP Shutdown	12/2002	2.2
No. 2 Crude Unit, H-25	10/2002	7.4
Isom Unit, H-33 (Hartford Integration)	10/2002	0.6
Isom Unit, H-32 (Hartford Integration)	10/2002	2.7
LSR Hydrotreating, H-31 (Hartford Integration)	10/2002	0.4
Hydrogen Plant, H-30 (Hartford Integration)	10/2002	2.5
Alkylation Heater, H-19 (Hartford Integration)	10/2002	5.2
FCCU Shutdown at Hartford	10/2002	68.6
	Total:	288.4

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With Proposed Modification	1,047.4
Creditable Contemporaneous Emission Increases	211.4
Creditable Contemporaneous Emission Decreases	288.4
	970.4

Attachment 4

PSD Applicability – SO_2 Netting Analysis

Contemporaneous Time Period: July 2002 through October 2009

Table I – Project Emissions Increases and Decreases

Project/Activity	Emission Change (Tons/Year)
CORE Project	-9,583.1

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Project/Activity	Permit Number	Date	Emissions Increase (Tons/Year)
North Property Flare	06030049	6/2007	0.1
Low Sulfur Gasoline (SZU)	05050062	2/2007	32.5
Ultra Low Sulfur Diesel	04050026	4/2006	101.4
Hartford Integration	03080006	4/2004	17.3
Tier 2	01120044	11/2003	28.0
FCCU 1 Alterations (Boiler 17)	03030069	9/2003	0.1
		Total:	179.4

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Project/Activity	Date	Emissions Decrease (Tons/Year)
HTR-VF1-North	12/2009	0.1
HTR-VF1-South	12/2009	0.1
HTR-BEU-HM1 Shutdown	12/2008	1.0
HTR-BEU-HM2 Shutdown	12/2008	0.7
Boiler 16 Shutdown	12/2008	3.0
North Property Ground Flare Decommissioned	7/2007	2.9
HTR-KHT	4/2006	1.2
CR-3 2^{nd} Reheat Heater (fuel switch)	11/2002	339.0
CR-3 1^{st} Reheat Heater (fuel switch)	11/2002	646.6
CR-3 Charge Heater (fuel switch)	11/2002	663.0
No. 2 Crude Unit, H-25	10/2002	0.8
Isom Unit, H-33 (Hartford Integration)	10/2002	0.1
Isom Unit, H-32 (Hartford Integration)	10/2002	0.3
Hydrogen Plant, H-30 (Hartford Integration)	10/2002	0.3
Alkylation Heater, H-19 (Hartford Integration)	10/2002	0.6
FCCU Shutdown at Hartford	10/2002	73.9
	Total:	1,733.6

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With Proposed Modification	- 9,583.1
Creditable Contemporaneous Emission Increases	179.4
Creditable Contemporaneous Emission Decreases	1,733.6
	-11,137.3

Attachment 5

Non-attainment NSR Applicability - VOM Netting Analysis (8-hour Ozone)

Contemporaneous Time Period: May 2001 through October 2009

Table I – Project Emissions Increases and Decreases

Project/Activity	Emission Change (Tons/Year)
CORE Project	382.7

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Project/Activity	Permit Number	Date	Emissions Increase (Tons/Year)
Tank A-39-1	06100062	7/2007	2.4
Tank A-49-1	06100062	7/2008	2.4
Tank CH-243	06100051	6/2007	0.2
North Property Flare	06030049	6/2007	2.4
Low Sulfur Gasoline (SZU)	05050062	3/2007	32.4
Ultra Low Sulfur Diesel	04050026	4/2006	30.7
Tanks 32-1 and 33-1	05090047	3/2006	2.6
Tank 403 (Terminal)	05050044	9/2005	9.8
Tank A-19-1	03020012	5/2005	2.8
Hartford Integration	03080006	4/2004	7.4
Tank A-157	03020012	1/2004	8.4
Tank D-9-1	02060051	1/2004	0.4
Tier 2	01120044	11/2003	37.6
FCCU 1 Alterations (Boiler 17)	03030069	9/2003	0.1
Sludge Processing Unit	01120042	3/2002	3.1
RAU Steam Reboiler	01060090	10/2001	0.9
		Total:	143.6

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Project/Activity	Date	Emissions Decrease (Tons/Year)
Tank D-50 Demo	2006-09	2.5
Tank F-12 Demo	2006-09	14.6
Tank F-35 Demo	2006-09	0.3
VF-1 Fugitives	12/2009	0.3
HTR-VF1-North	12/2009	1.0
HTR-VF1-South	12/2009	1.1
HTR-BEU-HM1 Shutdown	12/2008	1.7
HTR-BEU-HM2 Shutdown	12/2008	1.2
Boiler 16 Shutdown	12/2008	5.3
Tank A-49	9/2008	0.5
Tank A-39	9/2007	0.3
North Property Ground Flare Decommissioned	7/2007	1.4
HTR-KHT	4/2006	2.1
Gasoline Tank Replacement	3/2006	0.1

Project/Activity	Date	Emissions Decrease (Tons/Year)
Tank A-4 Demo	1/2006	0.2
Tank F-10 Demo	1/2006	0.5
Tank A-19 Demo	5/2005	4.7
Tank A-9 Demo	1/2004	0.4
Tank A-72 Firewater	12/2003	3.2
RFP Shutdown	12/2002	0.1
Tank 10-21	10/2002	1.9
Gasoline Storage Tanks (35-1, 35-2)	10/2002	6.3
No. 2 Crude Unit, H-25	10/2002	0.6
Isom Unit, H-32 (Hartford Integration)	10/2002	0.2
Hydrogen Plant, H-30 (Hartford Integration)	10/2002	0.2
Alkylation Heater, H-19 (Hartford Integration)	10/2002	0.4
Reroute/Elimination of Flare Streams at Hartford	10/2002	16.1
FCCU Shutdown at Hartford	10/2002	48.4
RAU Deethanizer Heater Shutdown	10/2001	0.9
	Total:	116.5

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With Proposed Modification	382.7
Creditable Contemporaneous Emission Increases	143.6
Creditable Contemporaneous Emission Decreases	116.5
	409.8

Attachment 6

PSD Applicability - PM Netting Analysis

Contemporaneous Time Period: July 2002 through October 2009

Table I – Project Emissions Increases and Decreases

Project/Activity	Emission Change (Tons/Year)
CORE Project	197.9

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Project/Activity	Permit Number	Date	Emissions Increase (Tons/Year)
Low Sulfur Gasoline (SZU)	05050062	2/2007	10.9
Ultra Low Sulfur Diesel	04050026	4/2006	42.2
Tier 2	01120044	11/2003	5.4
FCCU 1 Alterations (Boiler 17)	03030069	9/2003	0.1
		Total:	58.6

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Project/Activity	Date	Emissions Decrease (Tons/Year)
HTR-VF1-North	12/2009	1.3
HTR-VF1-South	12/2009	1.5
HTR-BEU-HM1 Shutdown	12/2008	2.4
HTR-BEU-HM2 Shutdown	12/2008	1.7
Boiler 16 Shutdown	12/2008	7.4
HTR-KHT	4/2006	2.9
RFP Shutdown	12/2002	0.2
CR-3 2nd Reheat Heater (fuel switch)	11/2002	11.1
CR-3 1st Reheat Heater (fuel switch)	11/2002	21.1
CR-3 Charge Heater (fuel switch)	11/2002	21.6
No. 2 Crude Unit, H-25	10/2002	0.6
Isom Unit, H-33 (Hartford Integration)	10/2002	0.1
Isom Unit, H-32 (Hartford Integration)	10/2002	0.2
LSR Hydrotreating, H-31 (Hartford Integration)	10/2002	---
Hydrogen Plant, H-30 (Hartford Integration)	10/2002	0.2
Alkylation Heater, H-19 (Hartford Integration)	10/2002	0.4
FCCU Shutdown at Hartford	10/2002	323.3
	Total:	396.0

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With Proposed Modification	197.9
Creditable Contemporaneous Emission Increases	58.6
Creditable Contemporaneous Emission Decreases	396.0
	-139.5

Attachment 7

PSD Applicability – PM_{10} Netting Analysis

Contemporaneous Time Period: July 2002 through October 2009

Table I – Project Emissions Increases and Decreases

Project/Activity	Emission Change (Tons/Year)
CORE Project	95.4

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Project/Activity	Permit Number	Date	Emissions Increase (Tons/Year)
Low Sulfur Gasoline (SZU)	05050062	2/2007	10.9
Ultra Low Sulfur Diesel	04050026	4/2006	42.2
Tier 2	01120044	11/2003	5.4
FCCU 1 Alterations (Boiler 17)	03030069	9/2003	0.1
		Total:	58.6

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Project/Activity	Date	Emissions Decrease (Tons/Year)
HTR-VF1-North	12/2009	1.3
HTR-VF1-South	12/2009	1.5
HTR-BEU-HM1 Shutdown	12/2008	2.4
HTR-BEU-HM2 Shutdown	12/2008	1.7
Boiler 16 Shutdown	12/2008	7.4
HTR-KHT	4/2006	2.9
RFP Shutdown	12/2002	0.2
CR-3 2nd Reheat Heater (fuel switch)	11/2002	8.0
CR-3 1st Reheat Heater (fuel switch)	11/2002	15.4
CR-3 Charge Heater (fuel switch)	11/2002	15.6
No. 2 Crude Unit, H-25	10/2002	0.6
Isom Unit, H-33 (Hartford Integration)	10/2002	0.1
Isom Unit, H-32 (Hartford Integration)	10/2002	0.2
Hydrogen Plant, H-30 (Hartford Integration)	10/2002	0.2
Alkylation Heater, H-19 (Hartford Integration)	10/2002	0.4
FCCU Shutdown at Hartford	10/2002	323.3
	Total:	381.2

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With Proposed Modification	95.4
Creditable Contemporaneous Emission Increases	58.6
Creditable Contemporaneous Emission Decreases	381.2
	-227.2

Attachment 8

Non-Attainment Area NSR Applicability – $PM_{2.5}^{*}$ Netting Analysis

Contemporaneous Time Period: May 2001 through October 2009

Table I – Project Emissions Increases and Decreases

Project/Activity	Emission Change (Tons/Year)
CORE Project	95.4

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Project/Activity	Permit Number	Date	Emissions Increase (Tons/Year)
Low Sulfur Gasoline (SZU)	05050062	3/2007	10.9
Ultra Low Sulfur Diesel	04050026	4/2006	42.2
Tier 2	01120044	11/2003	5.4
FCCU 1 Alterations (Boiler 17)	03030069	9/2003	0.1
		Total:	58.6

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Project/Activity	Date	Emissions Decrease (Tons/Year)
HTR-VF1-North	12/2009	1.3
HTR-VF1-South	12/2009	1.5
HTR-BEU-HM1 Shutdown	12/2008	2.4
HTR-BEU-HM2 Shutdown	12/2008	1.7
Boiler 16 Shutdown	12/2008	7.4
HTR-KHT	4/2006	2.9
RFP Shutdown	12/2002	0.2
CR-3 2nd Reheat Heater (fuel switch)	11/2002	8.0
CR-3 1st Reheat Heater (fuel switch)	11/2002	15.4
CR-3 Charge Heater (fuel switch)	11/2002	15.6
No. 2 Crude Unit, H-25	10/2002	0.6
Isom Unit, H-33 (Hartford Integration)	10/2002	0.1
Isom Unit, H-32 (Hartford Integration)	10/2002	0.2
Hydrogen Plant, H-30 (Hartford Integration)	10/2002	0.2
Alkylation Heater, H-19 (Hartford Integration)	10/2002	0.4
FCCU Shutdown at Hartford	10/2002	323.3
CR-1 2nd Inter-reactor Heater, H-3 (Fuel Switch)	2/2002	3.0
CR-1 1st Inter-reactor Heater, H-2 (Fuel Switch)	2/2002	6.4
CR-1 Feed Preheat, H-1 (Fuel Switch)	2/2002	6.5
RAU Deethanizer Heater Shutdown	10/2001	1.5
	Total:	398.6

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With Proposed Modification	95.4
Creditable Contemporaneous Emission Increases	58.6
Creditable Contemporaneous Emission Decreases	398.6
	-244.6

* Emissions of $PM_{2.5}$ in this table are expressed as emissions of PM_{10}, which is being used as a surrogate pollutant (see Condition 2.2).

Attachment 9.1 – Summary of BACT/LAER Determinations

Operation	Permit Section	BACT Determination for CO Control Technology/Emission Limit	LAER Determination for VOM Control Technology/Emission Limit
Heaters	4.1	Good combustion practices/0.02 lb/mmBtu, HHV	Good combustion practices/0.003 lb/mmBtu, HHV.
DW Thermal Oxidizer	4.2	Good combustion practices/0.082 lb/mmBtu, HHV.	Good combustion practices/0.005 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.
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 ppmdv corrected to 0% O_2 (365 rolling day avg.) and 500 ppmvd corrected to 0% O_2 on hourly average. FCCU 3: High Temperature Regeneration and CO Promoter; 150 ppmdv 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; FCCU 3: 11 lb/1000 bbl of feed.
Cooling Water Towers	4.6	N/A.	0.006 percent design drift loss.
New 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; and secondary BACT limits for annual CO emissions.	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; and secondary BACT limits for annual CO emissions.
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.

ATTACHMENT 9.2

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 x V x HHV	0.37 lb/mmBtu
VOM	E = EF x V x HHV	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.

HHV = Higher 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 HHV from any representative sample of a flaring event on the same day. If no representative sample is taken on that day, use HHV calculated from the last representative sample taken prior to the flaring event. For the Hydrogen Plant, the HHV 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.

$HHV_{adjusted} = HHV_{measured} - 326$ Btu/scf x {free hydrogen content (% by volume)/100}

Commercial Fuels

Pollutant	Natural Gas		Propane and Butane	
	Equation	EF	Equation	EF
CO	E = V x EF	35 lb/mmscf	E = V x 3500 x EF	0.032 lb/mmBtu
VOM	E = V x EF	7 lb/mmscf	E = V x 3500 x 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 higher 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:

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

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 Higher Heating Value of Vent Gases

If the higher heating value of vented gas is not measured or recorded for any flaring event, the higher heating value shall be calculated using the methodology below, unless a credible determination of higher 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 higher heating value shall be calculated using the following equation for the period of time this parameter was not measured or recorded:

$$HHV = HHV_{max} - 0.5(HHV_{max} - HHV_{ave})$$

Where:

HHV = Estimated higher heating value (Btu/scf)

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

HHV_{ave} = Average value of all HHV of vent gas measured and recorded for that flare for all sampled flaring events during previous operation preceding the subject flaring event.

ATTACHMENT 10: 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.