From: Brad Frost
To: Batty, Stuart; Hartshorn, Wally
Start: 7/19/2007
Due: 7/20/2007
Subject: Please post the attached two issued permits and the accompanying responsiveness summary to the recor

Please post the attached two issued permits and the accompanying responsiveness summary to the record for the ConocoPhillips CORE project. http://www.epa.state.il.us/public-notices/general-notices.html#conoco-phillips-wood-river

Thanks

[redacted]

Illinois Environmental Protection Agency
Bureau of Air
July 2007

Responsiveness Summary for
Public Comments and Questions on the
Coker and Refinery Expansion Project at the
Wood River Refinery in Roxana, Illinois and the
Wood River Products Terminal in Hartford, Illinois

Facility Identification and Application Nos.:
Refinery: 119090AAA, 06050052
Terminal: 119050AAN, 06110049

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DECISION

On July 19, 2007, the Illinois Environmental Protection Agency (Illinois EPA) Bureau of Air issued a construction permit to ConocoPhillips for the Coker and Refinery Expansion Project at its Wood River Refinery at 900 South Central Avenue in Roxana and the Wood River Products Terminal at 2150 South Delmar in Hartford. The Bureau of Air has also issued this summary to address questions relevant to the issuance of the air permit and other questions and comments raised during the comment period. Questions relating to the Bureau of Water permit will be addressed in a separate Responsiveness Summary when the Bureau of Water takes final action on the revised NPDES permit.

Copies of the permits can be obtained from the contact listed at the end of this document. The permits and additional copies of this document can also be obtained from the Illinois EPA website www.epa.state.il.us/public-notices/.

BACKGROUND

ConocoPhillips operates the Wood River Refinery located in Roxana, Illinois to produce a variety of petroleum products for distribution in the St. Louis, Chicago, and Indianapolis Metropolitan areas and throughout the Midwest. Wood River is positioned by refining capacity and by geographical location to process the growing volumes of heavy crude oil from Canada.

On May 15, 2006, the Illinois EPA, Bureau of Air received an application from ConocoPhillips for a Coker and Refinery Expansion (CORE) Project. The CORE Project entails installing facilities to increase both the total crude processing and percentage of heavier crude at the Wood River Refinery in order to increase the supply of petroleum products to the Upper Midwest. In order to handle the increased product throughput, ConocoPhillips is also proposing certain changes at the Wood River Products Terminal (also owned by ConocoPhillips). 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 the federal rules for Prevention of Significant Deterioration (PSD) and the state rules for Major Stationary Sources Construction and Modification (MSSCAM).

COMMENT PERIOD AND PUBLIC HEARING

The Illinois EPA Bureau of Air evaluates applications and issues permits for sources of emissions to the atmosphere. An air permit application must appropriately address compliance with applicable air pollution control laws and regulations before a permit can be issued. Following its initial technical review of ConocoPhillips' application, the Illinois EPA Bureau of Air made a preliminary determination that the applications met the standards for issuance of a construction permit and prepared draft permits for public review and comment.

ConocoPhillips requested that the Illinois EPA hold a public hearing on the CORE Project. This hearing also addressed ConocoPhillips's application for revision and reissuance of its National

Pollutant Discharge Elimination System (NPDES) permit to allow increased wastewater discharges from the Wood River Refinery due to the CORE project. The public comment period opened with the publication of a hearing notice in the Alton Telegraph on March 24, 2007. The hearing notice was published again in the Alton Telegraph on March 31st and April 7, 2007. The public hearing was held on May 8, 2007, at the Hartford Elementary School in Hartford. The purpose of this public hearing was to accept oral comments into the written hearing record and answer questions about the proposed project. The written comment period remained open until June 15, 2007.

AVAILABILITY OF DOCUMENTS

The construction permits issued to ConocoPhillips and this responsiveness summary are available on the Illinois Permit Database at www.epa.gov/region5/air/permits/ilonline.htm (please look for the documents under All Permit Records (sorted by name), PSD/Major NSR Records). Copies of these documents may also be obtained by contacting the Illinois EPA at the telephone numbers listed at the end of this document.

APPEAL PROVISIONS

The construction permits being issued for the proposed project grants approval to construct pursuant to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. Accordingly, individuals who filed comments on the draft permit or participated in the public hearing may petition the U.S. Environmental Protection Agency (USEPA) to review the PSD provisions of the issued permit. In addition, as comments were submitted on the draft permit for the proposed project that requested a change in the draft permit, the issued permit does not become effective until after the period for filing of an appeal has passed. The procedures governing appeals are contained in the Code of Federal Regulations (CFR), "Appeal of RCRA, UIC and PSD permits," 40 CFR 124.19. If an appeal request will be submitted to USEPA by a means other than regular mail, refer to the Environmental Appeals Board website at www.epa.gov/eab/eabfaq.htm#3 for instructions. If an appeal request will be filed by regular mail, it should be sent on a timely basis to the following address:

U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001
Telephone: 202/233-0122

COMMENTS & QUESTIONS WITH RESPONSES BY THE ILLINOIS EPA

General

1. People have catalytic converters on their cars. ConocoPhillips should put catalytic converters on its operations.

   The various emission units at the refinery are and will be equipped with appropriate equipment to control emissions of different pollutants. This control equipment does not include catalytic converters like those used on automobile engines. Catalytic converters are specifically designed to control certain pollutants as present in the exhaust from gasoline-fueled engines. The types of control equipment that are used on different emission units at the refinery depend on the particular emission characteristics of the units. For example, the emissions of nitrogen oxides (NO_x) from the Fluidized Catalytic Cracking (FCC) Units will be controlled by selective catalytic reduction (SCR) systems, which use ammonia and a catalyst bed to control emissions. NO_x emissions from heaters and boilers will be controlled with ultra low NO_x burners that minimize the formation of NO_x.

2. What is the current conventional crude distillation capacity of the refinery?

   The current conventional crude distillation capacity is 306,000 barrels per day.

3. What is the current output of diesel fuel from the refinery?

   ConocoPhillips indicates that the output of diesel fuel is approximately 70,000 barrels per day, all of which is low sulfur diesel.

4. What will be the cetane level of the ultra-low sulfur diesel fuel after the proposed project is complete? Is the cetane level dependent on renewable diesel production?

   At the public hearing, ConocoPhillips indicated that the cetane level of low sulfur diesel, currently at 48, is not expected to change. The specification for low-sulfur diesel is a minimum cetane level of 42. The cetane level of low sulfur fuel produced by the refinery is not dependent on renewable diesel production.

5. Are future projects expected to reduce aromatic content and increase cetane to meet the new USEPA regulations?

   The Illinois EPA is not able to predict the outcome of future projects at the refinery.

6. Is gasoline output with the proposed project dependent on the ethanol addition to meet the minimum octane requirements?

   According to ConocoPhillips, the refinery has the ability to make gasoline blendstocks that do not require ethanol addition. However, one of the advantages of

the project is the ability to make more "reformulated blendstock." This is the gasoline blendstock that is prepared for use with 10 percent ethanol.

7. What is the maximum vapor pressure specification for gasoline in summer months?

As explained by ConocoPhillips at the public hearing, there is no longer a vapor pressure specification. Reformulated gasoline has what is termed a "VOC limit," which is an equation that incorporates variables such as the actual distillation points of the blend, the sulfur content, etc.

8. What is the cap on vapor pressure of gasoline?

As explained by ConocoPhillips at the public hearing, since reformulated gasoline is now required, there is no longer a cap on the vapor pressure of gasoline. The actual vapor pressure for the reformulated gasoline blendstock produced by the refinery is now about 5.5 Reid vapor pressure (RVP). In the past, when the vapor pressure was capped, the RVP was 8.0. The reason that reformulated blendstock has to be lower than 5.5 RVP is because blending ethanol with gasoline elevates the vapor pressure, which must be compensated for by a lower RVP in the gasoline blendstock.

9. Will the proposed project enable ConocoPhillips to remove pentanes during the summer to allow ethanol blending? Also, if pentanes are taken out, where are they stored?

The new coker gas plant will improve the separation of pentanes from the gasoline blendstock. These pentanes are stored and blended into conventional gasoline for use in attainment areas.

10. How much natural gas does the refinery use today compared with how much it will use after the proposed project? Will hydrogen be produced from natural gas?

The main source of fuel for use in the refinery is refinery fuel gas produced as a byproduct of refining operations. According to ConocoPhillips, the refinery would typically use about 40 million standard cubic feet of natural gas per day after the proposed project, which is what it currently uses. The proposed hydrogen plant will use refinery gas as a feedstock. The need for hydrogen is minimized by the using of coking as an initial cracking process. As related to minimization of flaring, use of natural gas to supplement the fuel supply to the refinery is desirable as it provides the necessary flexibility to be able to consistently recover waste gas for use as fuel.

11. Rather than flaring waste gases, ConocoPhillips should capture the energy value of waste gases by capturing them and using them as fuel.

These recovery systems are already in place at the refinery. For example, the majority of fuel gases used in the refinery, which are used as fuel in the heaters and boilers, comes from recovered process gas.

12. I am concerned about benzene releases from the refinery.

A variety of federal regulatory programs currently in place are acting to reduce releases of benzene from the refinery. In addition, USEPA is adopting regulations to reduce the benzene emissions from automobiles and other gasoline powered vehicles, which would require a significant reduction in the benzene content of gasoline.

13. I am concerned about the amount and quality of wastewater discharged from the refinery.

Comments and questions about wastewater discharges will be addressed by the Illinois EPA's Bureau of Water when it takes final action on ConocoPhillips' application for a revised NPDES permit for the Wood River Refinery.

14. We are running out of gas. We've reached maximum production, and we've got to find the gas or the petroleum and we have to use it at the same time. We have to conserve. It doesn't make sense to use it up as fast as we can because we have children and grandchildren to think about. The other thing that's a reality is the problem of global warming issue that we all have to deal with. I hope that ConocoPhillips will look into using renewable sources of energy at this refinery. Are there any plans to try to use solar panels or wind or electricity generated from the river as part of the proposed project?

As discussed by ConocoPhillips at the public hearing, ConocoPhillips has a technology group that is looking into alternative sources of power, but at this point in time they do not fit into this particular project.

15. What additional safety measures can be taken by ConocoPhillips to assure the safety of the workers and the surrounding community should a major incident occur? What warning alert system is in place for the surrounding communities in the event of a chemical leak, explosion or toxic release? A full emergency community alert system should be in place that includes a telephone warning system and community warning signals that distinguish whether residents should evacuate or seek cover inside, with the environmental standards.

ConocoPhillips indicates that worker safety is always a concern, both to protect individual workers from accidents and to prevent incidents. Work to improve worker safety, including safety awareness, safety compliance and operational and process changes to improve safety, occur on an ongoing basis. These actions also reduce risks for nearby residents. The refinery does have a community alert network, by which it can quickly contact area residents by phone in the case of an emergency.

16. The draft permit does not address new equipment and process changes for production of renewable diesel fuel from animal fats and vegetable oils, as recently announced by ConocoPhillips. If this activity is going to occur at the Wood River refinery, why is there nothing in the permit application and the draft permit relating to these plans?

The production of renewable diesel fuel is not addressed by the application for this permit or the permit itself because renewable diesel fuel is not part of the CORE project that is being addressed. ConocoPhillips has not announced specific plans for the Wood River refinery in this regard. If ConocoPhillips decides to produce renewable diesel fuel at the Wood River refinery, a separate construction permit would be required for the new equipment and process changes that would be involved with the project. The changes in emission that would accompany the project would be addressed during the processing of that application.

Air Pollution

17. How many odor complaints were received due to the Wood River refinery during the last three years, and what was the nature of them? What evaluations and equipment improvements have been carried out in order to eliminate odor complaints? Have evaluations been performed to eliminate odor complaints in the new project?

Five odor complaints have been received by the Illinois EPA in the past three years due to "refinery-type" odors. Three were petroleum odors in the Hartford area. One was a sulfur odor in the South Roxana area. One was a pungent type odor in the Wood River area.

The refinery was granted a construction permit in May 2006 to replace a ground level flare with an elevated flare. The use of an elevated flare as opposed to a ground level unit will reduce any potential for odor associated with the operation of this flare.

Additional odors are not anticipated to result from this project. One of the principal concerns for odors is emissions of hydrogen sulfide (H_2S). The control equipment in place today and the proposed controls in this project will result in minimal emissions of H_2S. If odors do occur, the Illinois EPA will investigate and take appropriate action for each odor complaint that it receives. If equipment is not being operated properly, the solution is obvious. If equipment is operated properly but nuisance odors occur, further investigation would be needed to determine what should be done to alter the operation to mitigate or eliminate such odors.

18. When the wind blows from that direction where I live, about a half mile away, I smell the coker when it rains. The crude oil odor is so bad. Is it going to be worse?

Although there have been a handful of complaints due to refinery type odors, none have been related to the operation of the existing coking unit. Operation of a second coking unit is not expected to generate additional odors at the refinery.

19. I live about three miles downwind of the refinery and I have had asthma all my life. I cannot imagine what it would be like to have more particles in the air.

While the project itself will have emissions of particulate matter, they will be more than offset by the reductions in emissions of particulate matter from existing units, so there will be a net decrease in particulate matter emissions. (Refer to the Attachments to the permit that address emissions of particulate matter.

New Source Review

BACT/LAER

20. Can the Illinois EPA provide a listing of the emission units that ConocoPhillips purchased from Premcor?

    Appendix C of the Consent Decree contains a list of assets ConocoPhillips purchased from Premcor. This Consent Decree can be found on the internet at http://www.epa.gov/compliance/resources/decrees/civil/caa/conocophillips-cd.pdf.

21. What does "lowest achievable emission rate" mean?

    The lowest achievable emission rate is the most stringent emission limit derived from either (1) the most stringent emission limitation contained in the implementation plan of any state for such class or category of source; or (2) the most stringent emission limitation achieved in practice by such class or category of source.

22. ConocoPhillips should invest up front in better control technology at the refinery.

    ConocoPhillips is required to upgrade emission control technology on various units at the refinery pursuant to the Consent Decree, which requires upgrades of control equipment s on boilers and heaters, the sulfur recovery plants, and catalytic cracking units. All units at the refinery must comply with applicable federal NESHAP standards. For new and modified units affected by the proposed project, in addition to complying with federal NSPS standards, ConocoPhillips must implement Best Available Control Technology (BACT) for emissions of carbon monoxide (CO) and the Lowest Achieve Emission Rate for emissions of volatile organic material (VOM).

23. If this project is approved, ConocoPhillips should be required to use the best available emission control technology, regardless of the cost. It should also not be able to do any emissions trading. ConocoPhillips can afford to do everything possible to reduce the emissions from the refinery after this project and it should be required to do that.

    This project is subject to New Source Review for emissions of VOM and CO. Accordingly, ConocoPhillips must implement the Lowest Achievable Emission Rate (LAER) for VOM emissions and the Best Available Control Technology (BACT) for CO emissions. LAER does not consider cost of controls unless the cost of maintaining a particular level of control would be so great that a project could not

be built or operated at any location or reasonable set of circumstances. Cost factors can be considered in a BACT determination, to the extent allowed by USEPA rules and guidance. Cost was not a significant factor in the determinations of BACT and LAER made for the proposed project.

24. The CO emission limit proposed in the application as BACT for flaring, 0.37 lbs/million Btu, would not be enforceable. There is no practical method to enforce this limit, which by its nature is an emission factor and not a measurement. ConocoPhillips also has not proposed any method to verify compliance with this limit. It would be very convenient for ConocoPhillips to have a BACT limit that by definition is met independent of how much CO a flare emits, with the calculated emissions always being equal to the limit.

As noted by this comment, the CO emission limit proposed by ConocoPhillips as BACT for flaring is a USEPA emission factor and was not intended to be enforceable in the same manner as a more traditional emission limit. Instead, the proposed CO emission limit was intended to serve as a representation of the CO emissions of a properly operated flare. However, as implied by this comment, proper operation of a flare should be directly addressed by specifying the particular work practices that must be implemented for the flare. It would be poor regulatory practice to rely on a emission limit to implicitly require proper operation of a flare as specific practices for proper operation can readily be set. In addition, setting BACT solely in terms of an emission limit would not act to require practices to prevent and minimize flaring.

25. The CO emission limit proposed in the application by ConocoPhillips as BACT for flaring, 0.37 lbs/million Btu (proposed on page 7-9 of the application) was correctly rejected by the Illinois EPA. Setting BACT as this emission limit would not serve to reduce CO emissions by reducing the amount of flaring that occurs. While it does not appear that the Illinois EPA has applied this limit as BACT, it is what ConocoPhillips proposed. In case the Illinois EPA is still considering this limit or has somehow included it in its calculations underlying other limits in the draft permit, the Illinois EPA should reject such a notion. The proposed limit is actually a USEPA emission factor for CO emissions expressed in terms of the fuel value of the waste gas that is flared. This factor has nothing to do with BACT. Such a limit would allow unlimited hours of routine flaring at this rate, and by definition is not the best available technology but is instead an average or typical CO emission factor for flaring.

The issued permit does not set BACT for CO in terms of this emission rate proposed by ConocoPhillips. BACT for CO is set in terms of work practices to minimize CO emissions, consistent with the general approach taken in the draft permit. These work practices have been further developed as a result of further review by the Illinois EPA in response to other public comments.

26. Project VOM flaring emissions do not meet LAER requirements. The Project Summary for the proposed project prepared by the Illinois EPA incorrectly implies that the main source of VOM from flaring is the pilot flame, so that this should be the main focus of

the LAER evaluation and no other source of flare emissions need be evaluated for LAER.[1] However, the largest contributor to VOM emissions from flaring is the waste gases that are flared, since a percentage of the VOM is not destroyed and is emitted. Flares are typically considered to have a VOM destruction efficiency of 98% with good combustion conditions, with 2% of VOM routed to the flare being emitted. This is a significant percentage given the nature and magnitude of flaring that can occur at a refinery. Therefore the statement above that "since flares themselves are VOM control devices, no additional control of the VOM that is generated through the combustion of pilot fuel gas is necessary" is doubly inaccurate. LAER requires measures to prevent flaring events entirely, rather than allowing flaring, which still emits VOM to the atmosphere.

The statement in the Project Summary addressed by this comment was not intended to have the further meaning claimed by this comment. Indeed, the statement is fully consistent with the further discussion in the comment, as it addresses waste gases, rather than the pilot flame, as the principal contributor to CO and VOM emissions from flaring and the appropriate focus of a BACT and LAER evaluation for flaring.

27. The draft permit would set "blended limits" on emissions from new flares and other units so that separate BACT and LAER limits for flaring would not be set. In particular, Condition 4.7.6 of the draft permit, which should address only flaring, would set emission limits for the Delayed Coker Unit Flare (DCUF) that may also address other operations related to the new coker. The limits that are set for the new Hydrogen Plant (HP2) would address the Hydrogen Plant Heater (HP2 H-1), the associated Cooling Water Tower (CWT 24) and, fugitive emissions, as well as the flare (HP2F). The scope of these limits obscures exactly how much emissions of CO and VOM would be allowed for flaring with BACT and LAER. The application must provide a clear and complete project description and the permit must set limits for the individual emission units to ensure that each unit meets BACT and LAER.

The permit does not set "blended" limits for the permitted annual emissions of the flare for the new Delayed Coker Unit and this flare's permitted emissions of CO and VOM are set by Condition 4.7.6.

While blended limits are set for the permitted annual emissions of the flare for the new Hydrogen Plant, the flare is permitted to emit up to the limits in Condition 4.7.6. However, separate, lower limits are also set in Condition 4.1.6 for the process heater for the plant, Heater HP2 H-1. Condition 4.6.6 sets a limit on the VOM emissions of Cooling Water Tower 24, allowing only minimal VOM emissions. The emissions of the flare by itself are expected to be no more than the difference in these limits. For example, the expected annual emissions of CO would be no more

[1] "The RBLC database states for past permits that since flares are themselves VOM control devices, no additional control of the VOM from the combustion of pilot fuel gas is necessary. Therefore, no additional VOM control technologies are necessary for the two new flares." Project Summary, page 19.

than 36.2 tons.[2] While annual CO emissions could be greater (but in no case more than 147.9 tons as limited by Condition 4.7.6), this could only occur with circumstances that acted to lower CO emissions of the process heater. This approach has been taken for the new Hydrogen Plant given the nature and design of the unit, which generates a low VOM content, byproduct waste gas stream that is normally used as fuel in the unit itself.

28. The BACT/LAER evaluation for flaring did not evaluate the most stringent technologies available, which prevent entire flaring events and achieve the maximum degree of CO and VOM emission reductions. In this regard, the application incorrectly indicates that there are no "technically feasible CO control options" for the flares. (See Sections 7.3 of the application.) Other refineries have equipment and practices that minimize flaring emissions by minimizing flaring. Such approaches were not evaluated for the project. Preventing flaring events completely or minimizing the quantities of gases flared is the best method to prevent both VOM and CO emissions and all other flaring emissions (including carbon dioxide (CO_2)). Such methods were not evaluated in the application for the proposed project.

The BACT/LAER evaluations for the proposed project for flaring was made based on the features in the design of the new Delayed Coker Unit that will act to minimize flaring and in the context of existing requirements that address flaring at the Wood River refinery. In particular, the Consent Decree also includes requirements related to hydrocarbon flaring events, as is relevant to emissions of CO and VOM from flaring. The cause of significant hydrocarbon flaring incidents must be investigated, including performance of root cause analyses, steps must be taken to correct the conditions that cause such incidents, and the number and extent of such incidents must be minimized. Detailed reporting is also required for these incidents. Provisions have been included in the issued permit that make similar requirement applicable for the new flares that would be installed with the proposed project.

29. Additional evaluation of BACT and LAER is needed for venting of pressure relief devices to gas recovery systems (while adding sufficient compressor capacity so that this does not cause additional flaring).

Pressure relief devices are addressed by the provisions for flaring, as they are mechanisms through which waste gases are vented from process units at refineries for recovery or flaring.

30. The annual VOM emission rate from flaring achieved by Shell, Martinez, should be used as the basis to set a LAER limit for the proposed project. This results in a LAER limit for the Wood River refinery of 5.9 tons/year, given that the Wood River refinery is about four times larger than the Martinez refinery.[3] Shell states in its Flare Minimization Plan that it has been able to achieve low flaring emissions including emergencies in a safe

[2] 147.9 tons (overall limit on CO emissions) – 111.7 tons (limit on heater CO emissions) = 36.2 tons (remainder available for flare).

[3] (385,000 barrels per day (bpd) projected for ConocoPhillips)/(98,500 bpd Shell Martinez) x 1.5 tpy = 5.9 tpy

manner. Nothing in the BAAQMD flare rule with its requirement for a Flare Minimization Plan (FMP) causes any compromise in safe refinery operations, which allow flaring in a true emergency. However, the FMP does require rigorous monitoring, reporting, planning, and evaluation of flare events, and equipment improvements so that methods and equipment are in place to prevent emergencies and minimize flaring. These methods make the refinery safer by minimizing emergency shutdowns and reducing repeated flaring emissions.

The information cited in this comment does not support setting a LAER requirement for the Wood River refinery that is expressed in terms of annual emissions. As noted by the comment, the relevant BAAQMD regulations do not prohibit flaring, as flaring is an appropriate action to address disposal of process gas in emergencies. Likewise, Flare Minimization Plan prepared by Shell Martinez indicates that none of the procedures that are part of that plan would restrict access to the flares when flaring is viewed as necessary for personnel or equipment safety, which further necessitates flaring by operators without hesitation when warranted for safety. Setting a limit in terms of annual emissions of flaring, in the manner proposed by this comment, would potentially act to prohibit flaring when it was appropriate. It would set an absolute, enforceable limit on the extent of flaring that could occur at the refinery independent of the actual circumstances at the refinery in a particular year.

31. Additional evaluation of LAER is required for fugitive emissions for the refinery as a whole to provide baseline and future conditions with increased capacity, which will likely lead to increases in fugitive emissions. Information on frequency of inspection of valves, flanges, pumps, and compressors for leaks and information on any past violations at the refinery involving these operations should be provided. Lists should be provided including the numbers of all types of valves, flanges, pumps, and compressor seals.

LAER for VOM emissions due to component leaks is appropriately addressed by reliance upon and reference to the provisions of the NESHAP for Petroleum Refineries that address components leaks. The NESHAP provides a comprehensive approach to this source of emissions for very effective control of emissions. It requires implementation of a Leak Detection And Repair (LDAR) program to identify and repair leaking components in a timely manner. As certain types of service and applications are more likely to have components that experience frequent leaks and require repairs and follow-up monitoring if conventional types of fittings are used, the NESHAP leads to use of "advanced fittings," as discussed in this comment, in those applications. This is because of the stringent definition of the NESHAP for a leaking component. At the same time, advanced fittings are not required in circumstances in which they might actually lead to increased emissions, as advanced fitting are not as reliable under certain types and conditions of service.

The Consent Decree addresses VOM emission from existing components at the refinery, as it requires enhancements to the LDAR Program for existing components. These enhancements should act to significantly reduce the VOM

emissions from leaking components at the existing process units at the refinery.

Tables C-3a and C-3b of the application provide a listing of the various types of components to be installed, type of service for each components, quantity of each component type, and the area (process unit) in which the components would be installed.

32. Additional evaluation of LAER is required for VOM emissions from wastewater treatment tanks and ponds, including evaluation of upstream controls to prevent contamination of wastewater that leads to emissions of hydrocarbons and wastewater containing hydrocarbons and other pollutants and enclosure of any open wastewater systems, and data on concentration of hydrocarbons (lighter products and heavy diesel-range) and other contaminants in the wastewater.

LAER is appropriately set for wastewater treatment plant operations. Pollution prevention techniques are well established to prevent avoidable contamination of wastewater. As such contamination does occur and is inevitable give the nature of petroleum refining. The initial focus for control of emissions of VOM and other volatile pollutants from wastewater is containing such materials with the wastewater. This enables emissions of these materials to be controlled in the initial treatment units, which are designed to separate volatile material from the wastewater, rather than being lost directly to the atmosphere from the drain system as wastewater is being transported to enclosed treatment units. The VOM emissions from the initial treatment units are then readily controlled as the emissions are combustible. The VOM emissions generated as a byproduct of subsequent treatment units are also readily controlled as units are enclosed and the bulk of the gas stream is methane produced from anaeraobic wastewater treatment.

Data on the presence of hydrocarbons in the wastewater would not be useful, as it would not directly correlate with the potential VOM emissions from treatment plant operations. In particular, the presence of product materials should be expected to reduce VOM emissions as VOM emissions would dissolve in such compounds and then be readily removed in the oil water separators.

33. LAER for VOM emissions for the new storage tanks should require that tanks be equipped with unslotted guidepoles, rather than slotted guidepoles. Unslotted guidepoles should also be installed on existing storage tanks. This is because slotted guidepoles have a significant contribution to the VOM emissions of a floating roof tank.

Slotted guideposts that are closed at the top and equipped with sleeves and wipers, as would be used for the new tanks, do not contribute significantly to the VOM emissions from a floating roof tank. The use of unslotted guideposts and appropriately equipped slotted guideposts, cannot be distinguished for purposes of control of VOM emissions, based on USEPA emissions estimation methodology for tanks. In part, this is because slotted guideposts eliminate the need for separate fittings on a tank for sampling and level measurements, which also contribute to

VOM emissions. As a result, the net effect of use of slotted guideposts is not significant.

34. Additional evaluation of LAER is required for existing storage tanks at the refinery, which will have increased throughput due to the project, which should be upgraded to BACT. The application should have listed all storage tanks for an evaluation of baseline conditions including tank type, product, throughput, information on tank fittings and controls, past violations, tank degassing procedures, tank cleaning procedures, etc.

The existing tanks for which LAER requirements have not been set are not subject to LAER because they are not being physically modified and will not experience a change in the method of operation. The application does addresses increases in VOM emissions at existing tanks that will potentially occur due to increases in the throughput of these tanks as a result of the project.

AIR QUALITY ANALYSIS AND EMISSION OFFSETS

35. Has there been an evaluation by the Illinois EPA of cumulative impacts of this project in conjunction with the other nearby sources such as US Steel in Granite City?

This project will potentially result in an increase in emissions of CO that would qualify as significant under the federal rules for Prevention of Significant Deterioration (PSD). The air quality impact analysis performed for CO emissions for the proposed project shows that air quality for CO will not be significantly impacted by the project. Modeling of other PSD pollutants was not performed or required for the proposed project as emissions of these other PSD pollutants will either decrease or not increase significantly with the project as compared to the applicable PSD significant emission rate. Accordingly, air quality for these PSD pollutants will improve or not change significantly.

The role of the Wood River refinery in regional air quality for ozone and $PM_{2.5}$, for which the Greater St. Louis area is also currently nonattainment, will be addressed by the Illinois EPA and the Missouri Department of Natural Resources. This will occur during the air quality analysis that will be part of the development of the plans to bring the area into attainment with the National Ambient Air Quality Standards for ozone and $PM_{2.5}$.

36. Through emission offsets, clean air in St. Louis is being traded for dirty air in Roxana.

The offsets for emissions of VOM required for the proposed project do not trade clean air in one location for dirty air in another, as both St. Louis and Roxana are located in the Greater St. Louis area. This is because the ozone in the ambient air is not emitted from sources but is formed in the atmosphere from photochemical reactions of precursor compounds, i.e., VOM and NO_x, in the presence of sunlight. High ambient levels of ozone that exceed the National Ambient Air Quality Standard may occur many miles downwind from a collection of sources at which

precursor compounds are emitted. Long range transport of precursors is also important for ozone air quality as transport affects the levels of precursors in the air entering urban areas. Given these circumstances, the Greater St. Louis area is a single nonattainment area, with an overall problem with nonattainment of the ozone air quality standard. Given the nature of the problem, it is not possible to distinguish or differentiate the effects on ozone air quality from emissions of VOM in Roxana from those in St. Louis.

Incidentally, the planned offsets also satisfy applicable regulatory requirements. Illinois' rules governing major modifications in nonattainment areas, which reflect the provisions of the Clean Air Act, require emissions offsets for VOM to be obtained from within the same nonattainment area as a proposed project. The emission offsets planned for this project clearly meet this requirement.

37. What is the name of the source providing the VOM emission offsets for this project?

The offsets will come from JW Aluminum Company, which is located just southwest of downtown St. Louis.

38. What is the status of the Premcor Consent Decree and how is it managed with the Consent Decree for ConocoPhillips?

The Consent Decree previously signed by Premcor (99-87-GPM) has effectively been incorporated into the new Consent Decree with ConocoPhillips (H-05-0258) as is shown by the provisions in the new decree addressing the Distilling West FCC Unit.

39. Credits for something that was required under a consent decree should not be available for use in a netting or offset transaction.

The relevant provision of the Consent Decree that addresses the ability to utilize credits for the proposed project is Paragraph 262(d). This paragraph provides that if ConocoPhillips has a single project that involves installation of Consent Decree controls as well as other construction that would occur at the same time and be permitted as a single project, ConocoPhillips can utilize the emissions decreases from the installation of controls required by the Consent Decree for that project.

40. How is each unit purchased from Premcor taken into account in the netting analysis?

The permit for the project includes information showing how each unit is or is not used in the netting exercise for the proposed project. (Refer to the permit, Table III in Attachments 2 through 8.)

ANALYSIS OF ALTERNATIVES

41. Pollution prevention methods and project alternatives to coking, which would avoid the various impacts from coking, should have been publicly evaluated.

There are not "pollution prevention methods" available to ConocoPhillips that would avoid the need for coking. While the heavy stream of material that will be coked could be sold as asphalt, the markets for asphalt are both limited and seasonal. If this stream were sold as asphalt, this stream of material also would not be available to be refined into gasoline and diesel fuel, which are the products of the refinery for which consumption is increasing.

Coking is a modern crude oil processing technology that is routinely used at refineries for the purposes and in the circumstances in which ConocoPhillips would use it. The reasons why this technology is used in particular situation relate to well-recognized factors that affect decisions by any refinery with respect to process equipment. These include availability and cost of crude oil for the refinery given its location, the amounts of different products that consumed by local markets, the value of different products, the type of processing that is needed to produce different products given the nature of the crude oil supply, the reliability, yield, energy consumption and other demands of different processes, the capacity and capability of existing equipment at a refinery, the ability to meet or supplement the demand for certain products by other means, competition from other companies to meet the demand, etc. Given the common use of coking processes to crack heavy petroleum streams distilled from crude oil or bitumen, it is not necessary for ConocoPhillips to reveal the specific evaluations and business decision-making that led up to the proposed project.

42. Why shouldn't the refinery use a hydrocracker in conjunction with the delayed coker?

The primary conversion processes commonly evaluated are non-catalytic (e.g., delayed coking) and catalytic (e.g., hydrocracking). A refinery must generally determine which process is more advantageous based on criteria such as the composition of crude oil supply that is available for the refinery, operating and maintenance needs, frequency of start-ups, and markets for different products. Because the Wood River refinery is an existing refinery, ConocoPhillips must also consider which process will better handle the various products and intermediates from either the catalytic or non-catalytic process considering the existing processing equipment at the refinery. Of particular relevance is the fact that this refinery currently operates a delayed coker, which means that the proposed second delayed coker could be installed to be directly integrated with the existing downstream process units. Considerable improvements over the years have also been made to the safety of delayed cokers through the automatic unheading of coke drums. The Illinois EPA has determined that there is no reason to believe that the proposed coker is any less sophisticated or "modern" given the current configuration of the refinery and the types of crude slates which would be processed at the refinery. Also relevant for this choice is the energy balance and products of the refinery. The hydrocracking process is dependent upon the use of hydrogen, where as coking cracks hydrocarbons without need for hydrogen. Coking does produce a solid by-product for which there must be a suitable market.

43. If there were a cleaner feedstock available from Canada, it might lower emissions and require less water and wastewater and cleaning of pipelines and less processing at the Wood River refinery. It seems like a cleaner feedstock might reduce the environmental impact of the entire process from the start of the pipeline to the activities at the Wood River refinery.

The transportation process for this new supply of crude oil versus transport of partially refined products *will not result* in any additional energy impacts or cleaning. When the material is received at the refinery, all of the non-petroleum materials will be processed in the refinery just as existing crude is processed. For example, water will be extracted in the process, and it will be handled through the wastewater treatment plant consistent with typical refinery practices.

44. At the oil sands deposit in Alberta, Canada, state-of-the-art refining technology is being used to process some of bitumen, with a high-percentage conversion to light crude called synthetic crude oil, which is put into light products. In contrast, delayed coking is an older technology, which has been the subject of OSHA and USEPA safety warnings. Why is ConocoPhillips installing a delayed coker unit when it could use modern technology, like in Canada? Also, why couldn't the crude oil undergo hydrocracking in Canada before it is shipped? My understanding is that it could and the Wood River refinery would have more usable product and less coke and it would have less wastewater because too cut all that coke out and use voluminous amounts of water, which would help with the cone of depression and help with the discharges.

The refining of bitumen that takes place in Canada is performed because the bitumen recovered from oil sands is very viscous and cannot be directly shipped by conventional pipelines. It must generally either be blended or diluted with lighter petroleum products or processed or "upgraded," with the resulting material is generally referred to as "synthetic crude oil." This upgrading is performed using standard refining processes, including delayed coking followed by hydrocracking, as will also be performed with modern equipment at the Wood River refinery. The extent of processing that occurs in Canada is dictated by the need to produce a synthetic crude oil that is sufficiently liquid that is can be shipped by pipeline. It is more economical for existing refineries, which are closer to markets and have facilities to make a range of final products, to then complete the processing of the synthetic crude oil, rather than duplicate those facilities in Canada. Other factors also act to influence the extent of initial processing of the bitumen that is performed in Canada, e.g., the availability of natural gas to make the hydrogen needed for hydrocracking and the absence of local markets for petroleum coke.

45. Can a cleaner grade of crude oil be transported from Canada to the Wood River Refinery by using upgraded technology in Canada?

Production of a cleaner grade of crude oil in Canada would necessarily entail "full refining" of the crude oil in Canada. While it would be possible to construct a new

refinery in Canada at the source of the crude oil, it is more cost effective and efficient to pipe crude oil to existing refineries that already have the facilities to process material to supply the demands and environmental specifications for local markets.

46. Other refineries that process heavy crude have or have plans to build a facility to gasify the crude to make hydrogen and electricity for the refinery. From the perspective of national energy security, wouldn't it be better than the use of the natural gas, as proposed, and wouldn't that create more local jobs and wouldn't that be a higher value use of coke?

The Illinois EPA is not aware of any refineries that have facilities to gasify petroleum coke to directly produce hydrogen or that plan to construct such facilities. Certain refineries do have facilities to gasify petroleum coke to produce fuel gas, which can then be used as fuel in process units or in a cogeneration facility or used as a feedstock to produce hydrogen. A hydrogen plant is being developed to use pitch as a feedstock. However, steam methane reforming, as used at the Wood River refinery, using fuel gas or natural gas as a feedstock, is commonly used to produce hydrogen at refineries.

Most of the fuel combusted at the Wood River refinery is not natural gas as suggested by this comment. Rather, the primary fuel at the refinery is fuel gas that is a byproduct from certain refining processes. The gasification of petroleum coke would greatly increase the magnitude, duration and cost of expanding the Wood River refinery. It is also unclear what operational benefit would be derived from such effort as the refinery will produce sufficient refinery fuel gas and hydrogen for its operations without a gasification unit. Operation of a coke gasification unit would also add another element of complexity to the operation and management of the refinery. As gasification of petroleum coke is believed generally desirable, it is certainly possible for another company to pursue development of a new source specifically for that purpose, relying on ConocoPhillips and other refineries to provide its feedstock.

47. Some of the negative impacts of the use of petroleum coke as fuel in a boiler are its high sulfur content, which potentially contributes to higher emissions of sulfur dioxide (SO_2) and sulfuric acid mist from the boiler, the combustion characteristics of the coke, which potentially increases NO_x emissions, and the heavy metals in the ash.[4]

Use of petroleum coke as a fuel in a boiler generally poses emissions issues that are similar to those that are posed by use of high-sulfur coal in the boiler. That is, the boiler must be equipped with appropriate control systems for emissions of PM, NO_x and SO_2, as needed to comply with applicable emissions standards that apply to the boiler. While the trace levels of certain metals in petroleum coke, such as vanadium and nickel, are higher than in coal, emissions of these metals are controlled along

[4] *Challenges and Economics of Using Petroleum Coke for Power Generation*, World Energy Commission, http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/1_2_26.asp

with the PM and they end up in the ash. On the other hand, since the mercury content of petroleum coke is much lower than that of coal, use of petroleum coke does not pose the same concerns for mercury impact as the use of coal.

48. The analysis of alternatives to the proposed project should have considered the broader impacts on the United States of using crude oil from Canada. At a minimum, these impacts include the overall impacts additional energy use, additional hydrogen use, additional flaring, increases in refinery accidents, additional use of coke as fuel in power plants, impacts of new pipelines and pipeline accidents, and potential on impacts on regional air quality due to changes in vehicle fuels. These impacts and long-term implications are severe when considering added emissions criteria pollutants, toxic pollutants and greenhouse gases, as well as destruction of land and water resources, and impacts on people, plants, and wildlife.

It is beyond the scope of the analysis of alternatives for the proposed project to consider the impacts on the United States from using Canadian crude oil, as recommended by this project. The United States obtains crude oil from various oil fields, both domestic and foreign, with a variety of impacts associated with the production and transportation of that crude oil. While purchase of foreign crude oil reduces the environments impacts on the United States from oil production, it has economic impacts on the United States and the world economy. Use of domestic crude oil reduces those economic impacts but has environmental impacts. In some cases, those impacts can be severe. For example, the Exxon Valdez oil spill involved transportation of crude oil by tanker from Alaska.

GLOBAL WARMING

49. Condition 2.5 in the draft permit states that the Illinois EPA has broadly considered alternatives to the proposed project, as required by 35 IAC 203.306. However, the Illinois EPA was premature in finding that it has considered alternatives to the project. The high energy use of the project and resultant emissions of greenhouse gases should have been considered pursuant to 35 IAC 203.306, as a major environmental and social cost of the project. Alternatives to the project that would avoid severe project energy use and emissions of greenhouse gases should be evaluated, as required by 35 IAC 203.306. At a minimum, this cost of these impacts should be identified and evaluated, so that alternatives can be seriously evaluated.

Alternatives to the proposed project were reasonably analyzed. While there are theoretically alternatives to this project that would avoid the proposed project, these alternatives can be readily dismissed. For example, the existing motor vehicle fleet could be replaced with electrical vehicles, with electricity supplied by wind-based power plants. Not only is this not something that ConocoPhillips would undertake, but it is not something that could be undertaken as an alternative to the proposed project as it responds to needs for conventional fuels in the immediate future.

On a more realistic level, the continuing and increased demand for fuels in the

markets served by the Wood River refinery could potentially be met by refineries other than the Wood River refinery. However, importation of fuel to the Midwest from other locations would not eliminate the emissions from some similar project, as such project would still occur elsewhere to meet the public demand for fuels and changes in the global supplies of crude oil. As emissions of criteria pollutants affect air quality on a regional scale and greenhouse gases are of concern on a global scale, relocation of the project would be of uncertain benefits environmentally. Moreover, importation of fuels would certainly have significant impacts on residents of the greater St. Louis area as it would affect the cost and availability of fuels in the area. It could also have negative environmental effects as it would affect the availability of reformulated gasoline for the area, which the Wood River refinery produces as the local refinery serving the area. In summary, the proposed project is a reasonable proposal by ConocoPhillips for the Wood River refinery to continue in its historic role in supplying fuels to the Greater St. Louis area and the Midwest. While the refinery has impacts on the environment, those impacts are significantly outweighed by the benefits currently being provided for society of the fuels that the refinery produces.

50. In 2006, Governor Blagojevich announced a climate change initiative by the State of Illinois to address emissions of greenhouse gases, which will build on Illinois' role as a national leader in protecting public health and the environment. This initiative marks the beginning of serious efforts by Illinois to address global climate change and builds on steps that Illinois is already taking to lower emissions of greenhouse gases, such as providing incentives for energy efficiency and encouraging the use of wind power and biofuels.

Governor Blagojevich has instructed the Illinois Climate Change Advisory Group, which he has convened for this initiative, to evaluate a full range of policies and strategies to reduce Illinois' emissions of greenhouse gases. Accordingly, the Advisory Group is focused not only on the facilities that supply fuel and energy, but also on the facilities and people of Illinois who use that fuel and energy. This is critical as significant reductions in emissions of greenhouse gases requires comprehensive actions to reduce energy consumption, including significant improvements in the energy efficiency of transportation, heating, cooling, and lighting, machinery and appliances, etc. While facilities that produce fuels and energy, e.g., petroleum refineries, can <u>and do</u> make improvements to reduce the energy consumed in their operations, these reductions are not sufficient to roll back emissions of greenhouse gases. As related to emissions of greenhouse gases from "crude oil," a reduction in the usage of gasoline and other petroleum products usage is needed.[5] Thus the focus of efforts in Illinois to reduce emissions of greenhouse gases from use of petroleum-based fuels must be to actually reduce the usage of such fuels. This will also provide other benefits such as stabilizing fuel prices, maintaining and improving air quality, and reducing traffic congestion. The

[5] While renewable fuels, i.e., ethanol and biodiesel, can be substituted for some fuel, the extent of such substitution that is feasible is relatively minor in terms of the overall emissions of greenhouse gases attributable to use of petroleum-based fuels.

activities of the refineries that supply fuels are a secondary consideration in these efforts, both due to the lesser magnitude of their emissions and their role in meeting Illinois's current needs and demands for fuels.

51. The U.S. Global Change Research Program published a report on impacts of climate change in the Midwest,[6] which finds that, higher summer temperatures and resultant increased air pollution in the Midwest will result from climate change. This is because hotter summers could act to increase the formation of ground-level ozone, which is formed through reactions of precursor compounds energized by sunlight on hot days. As major urban areas in the Midwest are currently nonattainment for ozone, climate change is making it more difficult to attain and maintain compliance with the ozone air quality standards. The report also found that heat-related deaths in the region due to climate change will increase, and the report as a whole found many other severe impacts due to climate change. The public is relying on the Illinois EPA to seriously evaluate alternatives to the proposed project that will not only protect public health from traditional air pollutants, but also from greenhouse gases, whose effect is to exacerbate air pollution and threats to public health.

As observed by this comment, global warming potentially has myriad negative impacts on human health and welfare and the environment, both directly and indirectly. However, it is also obvious that the challenge of global warming will require a comprehensive regulatory approach in the United States, which is ultimately imposed by Congress on a national level. Until specific regulations are put into place by the appropriate state or national authorities, ad-hoc actions to compel individual action on global warming through conventional environmental permitting programs are capricious. Even if such actions were taken, they would probably provide only illusory benefits, as they would be limited in their scope to new projects. They would not reach or affect existing sources, which contribute the majority of emissions of concern. Such actions might also have a stifling effect on the continuing development and deployment of new technology to improve energy efficiency and reduce emissions of greenhouse gases, as such actions would stifle innovation or discourage capital investment.

52. The application for the proposed project does not contain information for emissions of CO_2, methane[7] and other greenhouse gases from the new and modified heaters that are part of the project, which could be readily calculated by ConocoPhillips. The analysis of alternatives to the project should have reviewed the environmental and social impacts of emissions of greenhouse gases, which requires a quantification of these emissions, in order to demonstrate that the benefits of the project will outweigh its environmental and social impacts, as required to comply with Illinois regulations. A full review of project

[6] Climate Change Impacts on the United States, The Potential Consequences of Climate Variability and Change, Overview: Midwest, by the National Assessment Synthesis Team, US Global Change Research Program, 2000, http://www.usgcrp.gov/usgcrp/Library/nationalassessment/7MW.pdf, (The U.S. Global Change Research Program (USGCRP) is a government research program codified by Congress in the Global Change Research Act of 1990.) Full webpage: http://www.usgcrp.gov/usgcrp/Library/nationalassessment/overviewmidwest.htm

[7] Many emissions points in the refinery emit methane, which is a potent greenhouse gas, 20 times stronger than CO_2, and a major component of the fuel gas used at refineries. Illinois' definition of VOM excludes methane.

alternatives should have also included prevention and/or mitigation of emissions of greenhouse gases. Estimates of CO_2 emissions were provided by ConocoPhillips for another recent proposal to expand its refinery in Rodeo California.[8] It showed that the increase in emissions of greenhouse gases would be larger than many of the decreases in emissions from California's Early Action measure, effectively wiping out decreases made in other sectors. Estimating emissions of greenhouse gases from the proposed project just makes good sense since the project will set refinery practice and the environmental impacts of the refinery for decades.

The important greenhouse gas emitted from processing of crude oil and use of petroleum refineries is CO_2. This is because CO_2 is the product of combustion when carbon, which makes up the bulk of crude oil, is burned. This is different from methane and other greenhouse gases, which are pollutants in the more traditional sense, as they are contaminants and processes may be manipulated or controlled to reduce the formation of these materials. For example, the trace levels of emissions of methane that accompany combustion of any fossil fuel can be minimized by good combustion practices. In contrast, CO_2 is the unavoidable product of combustion of carbon, as is desirable as it represents complete combustion of that carbon to CO_2, rather than CO.

As already discussed, use of petroleum-based fuels directly leads to emissions of greenhouse gases. The magnitude of this contribution is large, with activities related to use of petroleum products currently contributing about 45 percent of the CO_2 emissions of the United States. As observed by this comment, emissions of CO_2 can be readily calculated from information on the type and amount of fuel that is being burned. Emissions of CO_2 associated with use of crude oil can be roughly estimated using a factor of 1000 pounds of CO_2 per ton of crude oil consumed. Accordingly, as this project involves a nominal increase in the annual capacity of the Wood River refinery of about 27 million barrels, the project potentially involves handling crude oil that could annually contribute as much as about 12.5 million metric tons of CO_2 emissions to the atmosphere.[9] As the majority of these emissions would occur when gasoline, diesel and other petroleum products produced by the refinery are used, the split between consumption/emissions at the refinery and consumption/emissions of the users of fuels is of uncertain significance. Reductions in these emissions will require improvements in energy efficiency by the users as fuels so that less fuel is consumed on a regional, national and international level.

[8] ConocoPhillips is pursuing permit for a major expansion at its refinery in Rodeo California. For that project, ConocoPhillips provided an estimate of the CO_2 emissions increases, about 1.25 million metric tons per year. This is a large increase, as it is more than 1 % of the comprehensives inventory for emissions of greenhouse gases prepared by the BAAQMD for the entire Bay Area, which addresses emissions from industrial sources, cars, trucks, ships, building heating, etc. The proposed project at the Wood River refinery represents a much larger refinery and expansion (up to 385,000 bpd, compared to the Rodeo 76,000 bpd refinery) and involves heavy crude oil, which requires more processing than lighter crude oil. CO_2 emissions will be much higher for the proposed project than for the ConocoPhillips Rodeo refinery, which are already extremely large.

[9] While 12.5 million metric tons may see like a large number, global emissions of CO_2 are measured in terms of billions of metric tons per year.

53. ConocoPhillips has publicly announced plans to reduce emissions of greenhouse gases. In 2006, ConocoPhillips became the first major US oil company to join the US Climate Action Partnership. James Mulva, ConocoPhillips' chairman and chief executive has been reported as saying that "Voluntary programs are not going to meet the challenge of climate change," ... "The longer we wait - two or five years or more from now - it won't be mitigation, it will be adaptation."[10] Unfortunately, the proposed project is moving in the opposite direction, with more energy-intensive processing of very heavy Canadian crude oil.

In actual fact, ConocoPhillips went on record supporting mandatory, national regulations addressing greenhouse gas emissions. This is consistent with its participation in the US Climate Action Partnership, which is a diverse group of businesses and environmental leaders that have come together to call for mandatory action on climate change, endorsing a comprehensive approach involving phased targets for reduction of emissions of CO_2 accompanied by a range of policy approaches. ConocoPhillips should be praised for its endorsement of regulatory action to address global climate change, especially when certain other companies would prefer to ignore global warming. However, ConocoPhillips corporate position on climate change is not inconsistent with the current project, which would meet a need for fuel in the immediate future using an existing refinery.

54. Global warming is a scientific fact that is now accepted worldwide. The United States is far behind Europe in what it has done with alternative energy and energy conservation and ConocoPhillips is not helping. If ConocoPhillips wants to expand and get more energy, why doesn't it invest in some new alternative energy methods instead of investing in continued use of crude oil to produce fuels. Instead of building a new coker, why doesn't it put other processes at the refinery?

ConocoPhillips is pursuing the current project because its primary business is supplying petroleum based fuels, products for which there is both an ample need and even greater demand. As observed by this comment, the United States is far behind Europe and many other developed nations in actions that would reduce the demand for the petroleum-based fuels that ConocoPhillips produces. Other countries also provide stronger support for the development of alternative energy technologies, as will be critical to rollback emissions of greenhouse gas emissions.

55. Emissions of greenhouse gases should be monitored and measured. How much methane and CO_2 would be released by uncontrolled pressure-relief devices? How much $C0_2$ will be released by the hydrogen plant?

Treating emissions of CO_2 and other greenhouse gases as regulated air pollutant, as is effectively being requested by this comment, would be inconsistent with current Illinois law. In particular, CO_2 is a compound that is present in the earth's

[10] "ConocoPhillips: The anti-Exxon: The Texas-based oil company breaks with he other U.S. majors to support mandatory national regulation of greenhouse as emissions," *Fortune*, Marc Gunther, April 11, 2007, http://money.cnn.com/2007/04/10/news/companies/pluggedin_gunther_conocophillips.fortune/index.htm

atmosphere, occurring both naturally and as a product of fossil fuel combustion. CO_2 in the atmosphere has not been commonly regarded as an air "pollutant." Indeed, the ecosphere depends upon the presence of CO_2 emissions to support green plants. Historically, CO_2 in the ambient atmosphere has not been considered harmful to humans or the environment.

At the same time, the Illinois EPA is working to develop requirements for tracking and routine reporting of emissions of CO_2, and perhaps other greenhouse gases in Illinois in the near future. This activity would be comprehensive, as it would address all significant stationary sources of these emissions. Improved tracking of emissions of such emissions is important in conjunction with Illinois' current initiative to reduce emissions of greenhouse gases.

56. What energy efficiency evaluations were carried out for this project, if any?

ConocoPhillips indicated that is has an "energy action checklist" that sets energy standards that every new construction project must meet. For example, new process units must be designed so that the temperature of the final product is such that all usable heat energy has been recovered. This checklist is ConocoPhillips' way of evaluating proposed projects for energy efficiency.

57. How much additional methane will be emitted by flaring due to the proposed project?

Emissions of methane from the refinery from flaring should be decreasing due to the various measures that are being implemented to minimize flaring.

Air Permitting

FLARING

58. The proposed project will entail construction of two new flares and increased use of existing flares. These flares are subject to BACT for CO emissions and LAER for VOM emissions. However, the draft permit would not require BACT or LAER for flaring.

The existing flares are not subject to BACT or LAER because they are not being physically modified and will not experience a change in the method of operation. This is because they will be in the same service, with the same process stream and function, as at present. Indeed, due to the requirements of the Consent Decree it is appropriate to anticipate that emissions of the existing process flares at the refinery will be declining. The issued permit includes additional requirements as part of BACT and LAER for the new flares in response to public comments.

59. The application does not include emissions information related to flaring from the project or from contemporaneous projects over the last five years, which should have been provided. Not only is there a large potential to emit at the new flares, but emissions at existing flares will increase due to the project because of increased production at the

refinery. The application is not complete without this information and must be supplemented.

The application does include emissions information for new, modified and debottlenecked flares and for any increases in flaring and flaring emissions associated with contemporaneous projects.

60. USEPA prohibits routine flaring and requires preventative measures to minimize SO_2 emissions from flaring. A USEPA Enforcement Alert[11] warns that frequent, routine flaring, which may cause excessive, uncontrolled SO_2 emissions, is not considered "Good Pollution Control Practice," and may violate federal regulations adopted pursuant to the Clean Air Act. Unfortunately, none of these requirements are met by the proposed project. The application failed to provide the necessary analysis on available methods, such as having sufficient compressor capacity to rigorously prevent and minimize entire flaring events and thus achieve maximum controls and lowest emissions from flaring. Such methods minimize emissions of all pollutants from flaring, and are used at other refineries.

As already explained, the Wood River refinery is subject to requirements to minimize flaring as it contributes to SO_2 emissions. Incidentally, while expressing concerns about excessive flaring, the USEPA confirmed that the proper use of flaring is a good engineering practice, as flaring destroys hazardous and objectionable gases by burning those gases. Flaring also prevents injuries to employees, fires and explosions, and damage to equipment.

61. The application incorrectly states that there is no way to reduce CO emissions from flaring and at the same time control VOM emissions, assuming that either VOM waste gas must be flared or else directly emitted.[12] However, recovery of waste gas back to a refinery's fuel gas system acts to prevent both VOM and CO emissions from flaring.

This statement was made in the context of the Wood River refinery, where measures to reduce hydrocarbon and thus VOM emissions from flaring by minimizing and eliminating such events are in place. Given that such measures are in place, the flaring events that actually do occur must generally be considered unavoidable, as indicated in the application. (Certainly, any further discussion about whether a particular flaring event was avoidable will occur after the event has occurred.)

62. CO emissions from flaring are related to combustion efficiency, which varies. If the combustion efficiency of a flare were 100%, there would be no CO emissions from the flare. Flare combustion efficiency varies according to the quality of the gases burned, the

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[11] USEPA Enforcement Alert, Vol. 3, Number 9, October 2000
http://www.epa.gov/compliance/resources/newsletters/civil/enfalert/flaring.pdf

[12] "No process changes that would reduce the CO emissions exist. Since the flares serve as VOM control devices in an 8-hour ozone non-attainment area, their operation is necessary. Therefore, no CO control technologies exist for the new flares." Application, page 7-9

capacity of the flare, how well the flare mixes the fuels and air, flare exit velocity, wind conditions, etc. Combustion efficiency can vary from low, down to only 60% or less of VOM combusted to very high, over 99% efficiency. Regulators in Texas and California use destruction efficiencies down to 93% when calculating flare emissions when waste gas sent to a flare has a low Btu content instead of the 98% more commonly used in emission calculations. Many studies show that efficiency can be very low, down to even 30%. The ratios of emitted CO, CO_2, VOM, etc., also vary. Choosing USEPA's CO emission factor, which relates to average or typical conditions, for BACT for a flare would be unsound.

It is common practice to conservatively calculate VOM emissions from flaring using a minimum level of destruction efficiency so as to overstate VOM emissions. This level of combustion efficiency is 98 percent, which USEPA indicates is the minimum level of destruction efficiency that will generally be achieved when a flare is operated to comply with 40 CFR 60.18, as is required for flares at the Wood River refinery. Similar approaches are taken for emissions of other pollutants from flaring that are affected by destruction or combustion efficiency of the flare. While the destruction efficiency for flaring that does not comply with 40 CFR 60.18 may be lower than 98%, as discussed by this comment, this is not relevant to the flares at the Wood River refinery. In addition, this comment does not identify a method by which the effect of normal variation in destruction efficiency of a flare and its effect on VOM emissions could be readily determined in practice or show that such a method is needed.

63. The flare associated with the new hydrogen plant would not be "assisted" with either introduction of air or steam. Steam or air-assisted flares are considered basic to provide good mixing in a flare and maintain combustion efficiency. Non-assisted flares should not be considered to meet BACT requirements.

The waste gas from the hydrogen plant that would be flared, which should only occur during upsets or emergencies given the nature of hydrogen plants, is expected to be low-Btu gas, which is primarily CO and CO_2 and has a low VOM content. As the heat content of the waste gas is between 200 and 300 Btu per SCF, use of steam or air assist is not required for effective combustion, as reflected in USEPA's regulations for proper design and operation of flares.

64. There are many proven approaches for reducing the number of flaring episodes and the quantity of waste gas flared and thus reducing all flaring emissions. They include: 1) Having sufficient compressor capacity, including redundant compressor capacity to recycle waste gases to the refinery fuel gas system (especially important when the refinery is being expanded so that more waste gases may be produced); 2) Managing depressurization during unit shutdowns so that the gas recovery system is not overwhelmed; 3) Constructing stronger process vessels to increase working pressures to enable containment of process gases during shutdown rather than flaring; 4) Implementation of detailed procedures to diagnose and eliminate unnecessary flaring, and 5) Fixing equipment that repeatedly malfunctions and causes unnecessary "emergency"

flaring. A plan for minimizing flaring and root cause analysis for flaring activity that does occur are keys to preventing unnecessary flaring. These approaches are used at existing refineries and have been shown to lower the number and magnitude of flaring events. An analysis of such approaches was not provided for the proposed project and the draft permit would only superficially address these approaches to reducing flaring and flaring emissions.

As generally observed by this comment, there are many ways to reduce emissions from flaring. For the new process flare systems at the refinery, the various approaches to minimization of flaring and flaring emissions discussed in this comment are required as appropriate for the particular process units that are served by the flare system. This has been clarified in the conditions of the issued permit for flaring. The one exception is constructing stronger process vessels. This has not been identified as a reasonable or recommended approach to reducing flaring emissions. It would pose operational concerns as it would implicitly entail operation of process vessels at higher pressures. In addition, careful management of depressurization of vessels during unit shutdowns appears to be very effective in minimizing and eliminating shutdowns as a contributor to flaring.

65. The SCAQMD and the BAAQMD have both identified adequate compressor capacity for recovery of waste gas as being effective in minimizing flaring events and their associated emissions. This approach was not evaluated for the proposed project for BACT and LAER.

The new flare system for the new Delayed Coker Unit will include redundant waste gas compressors, as currently used at the Shell, Martinez refinery. A condition has been included in the issued permit requiring this as an element of BACT and LAER for this new flare system. The flare for the new hydrogen plant does not handle a waste gas that is suitable for recovery for use in the refinery fuel gas system.

66. Without rigorous monitoring, adequate compressor capacity, process control, and appropriate permit conditions, significant flaring can be expected at the Wood River refinery with the proposed project.

The extent of future flaring at the Wood River refinery is minimized by operational and economic incentives to maintain stable process operation with consistent product yields and to recover waste gas that is produced for use as fuel. ConocoPhillips also has a stated objective of minimizing its CO_2 emissions. Accordingly, it is unclear to what extent, if any, the permit must mandate particular action by ConocoPhillips to prevent significant flaring at the refinery in the future. Nevertheless, the issued permit mandates that ConocoPhillips take particular actions to minimize flaring, consistent with the actions that have been taken at and required of other refineries.

67. Without adequate compressor capacity, significant flaring can be expected at the Wood River refinery with the proposed project. The application does not provide information

for the nine existing flares in different areas of the refinery for baseline compressor capacity or the amount, if any, that this capacity would be increased with the proposed project. As found by the BAAQMD and SCAQMD, compressor capacity is key in preventing flaring. It allows the refinery to consistently recover waste gases for use as fuel, rather than flaring these gases with associated emissions. Adding compressor capacity, as discussed in its Flare Minimization Plan, enabled Shell, Martinez to reduce flaring, including emergency flaring, to very low levels compared to other refineries in the Bay Area. The Tesoro, Avon refinery (previously Tosco), also in the Bay Area, which had the worst flaring record prior to the BAAQMD rulemaking, reduced its emissions greatly by adding compressor capacity.

Adequate compressor capacity is only one approach to minimizing flaring. Whether other approached are adequate for the existing flares at the Wood River refinery or additional waste gas compression capacity will have to be installed at the refinery is not a matter that can be determined at this time as measures to reduce emissions from existing flares are ongoing. Whether additional compressor capacity should be installed for existing flare systems at the refinery is a matter that is appropriately dealt with in the context of the Consent Decree.

68. At the refineries in the Bay Area, flaring, including emergency flaring, was also further reduced after adoption of rules for flaring by the BAQMD, showing the feasibility of controlling flaring through prevention mechanisms. The principles and equipment used by refineries in the Bay Area must be applied with specificity to the proposed project.

For the flare for the Delayed Coking Unit, for which BACT and LAER are required, the issued permit requires that ConocoPhillips implement the measures similar to that specified by the BAAQMD to reduce flaring. These are preparation of and operation pursuant to a Flare Minimization Plan and performance of "root cause analyses" for significant flaring incidents. In this regard, the BAAQMD's flaring rules put into place certain administrative requirements whose purpose is to lead to reduction in flaring and flaring emissions. The rules do not identify or prescribe specific measures that refineries must use to reduce flaring. Thus, while the Delayed Coking Unit will have a gas recovery system with redundant compressor capacity as already discussed, this is not a measure that is mandated by the BAAQMD rules.

The BAAQMD's rules for flaring at petroleum refineries do not address flaring at wastewater treatment plants. At wastewater treatment plants, flares serve as control devices for the emissions from certain units and do not handle waste gas streams as are potential present with the operation and upset of process units at a refinery.

69. A detailed evaluation[13] of the refineries in the Bay Area, which reviewed data reported by the refineries and their Flare Minimization Plans, found that the dirtiest refinery processes caused more flaring, with more emissions, than other refinery processes. This

[13] "Flaring Prevention Measures," Communities for a Better Environment (CBE), Greg Karras, April 2007

is directly applicable to the Wood River refinery, which is expanding its dirtiest refining processes.

This evaluation found that certain refining processes had the potential to generate more emissions from flaring. Accordingly, it recommended that these particular processes be subject to especially thorough review with appropriate actions implemented to minimize flaring associated with these processes.

70. The application failed to evaluate LAER achieved in practice by refineries that rigorously implement approaches to minimize flaring. Shell has documented its approaches for minimizing flaring and achieving very low flaring emissions at its refinery in Martinez, California, in the Flare Minimization Plan for this refinery[14] required by BAAQMD rules. BACT and LAER for flaring at the Wood River refinery should be at least as stringent as the equipment and practices in place at the Shell Martinez refinery. Even before adoption of the BAAQMD rules, the Shell Martinez refinery did not have large flaring events compared to the large and routine flaring events, with substantial emissions, at other refineries in the Bay Area. The Shell Martinez refinery has continued to exhibit very low flaring emissions compared to other Bay Area refineries. The Flare Minimization Plan for the Shell Martinez refinery should be evaluated and the approaches applied to Wood River refinery in detail to satisfy BACT and LAER requirements.

In response to this comment, the Flare Minimization Plan prepared by Shell Martinez has been closely reviewed. The issued permit requires a Flaring Minimization Plan for the new coker flare being constructed as part of this project (coker flare) that address the various approaches that have been taken by Shell Martinez to reducing flaring, as presented in the Flare Minimization Plan for that refinery.

71. Shell, Martinez has two waste gas recovery compressors for dedicated use in its Delayed Coking Area, with each compressor having enough capacity to handle gases from this area when one of the compressors is out of service. ConocoPhillips should do the same.

As previously discussed, the flare system for the new Delayed Coker Unit will include redundant waste gas compressors, like the system at the Shell Martinez refinery. In this regard, Shell Martinez, with its Delayed Coker Unit that was installed in the mid-1990's, also provides anecdotal evidence that operation of a modern Delayed Coker Unit does not significantly contribute to flaring emissions, given Shell Martinez's excellent record on minimizing flaring emissions as cited by

[14] Shell's Flare Minimization Plan for the Martinez refinery indicates that "As the refinery already has very significant capital infrastructure for flare gas recovery in place, procedural modifications can be used to achieve much higher returns on a $/ton emissions reduction basis. New refinery procedures described in this Flare Minimization Plan address actions to further minimize flaring during process upsets and additional planning requirements for maintenance and turnaround activities. Careful planning of any activity with the potential for flaring is the most successful minimization approach that has been employed at SMR. Procedures for reporting and investigating all flaring provide means to learn from unanticipated events. The result of this work will be further reductions in flaring." Excerpt from the Shell Martinez Refinery, Flare Minimization Plan, Redacted Version, Revised March 25 2007, submitted to the Bay Area Air Quality Management District

this commenter.

72. The Shell Martinez Refinery Flare Minimization Plan emphasized the importance of thorough root cause analysis of flaring incidents to avoid similar events in the future and reduce emissions from flaring emissions. This measure is needed for the proposed project due both to the large increase in refinery capacity and the refinery's history of flaring.

The issued permit requires that root-cause analyses be performed for the new flare for the Delayed Coking Unit for any significant flaring incident for hydrocarbons.

73. Operational monitoring for waste gas that is flared is important to provide accurate data for emissions from flaring and to provide a factual basis for evaluation of the number and nature of flaring events and their associated emissions and to perform root cause analyses for flaring. Monitoring devices are available to track the flow of gases to a flare. Monitoring for the concentration of VOM and sulfur compounds in waste gases, in combination with records for pilot and purge gas flow, is needed to provide good information on the waste gas burned by a flare and the accompanying emissions.

The issued permit requires continuous monitoring to identify when waste gases are flared. This requirement is accompanied by requirements for monitoring or instrumentation to reasonably determine the amount of gas that is flared, requirements for sampling and analysis of waste gas or maintenance of records for the composition of the gas, and requirements for monitoring or records related to fuel usage for the pilot and venting of purge gas to the flare.

74. The draft permit would only superficially address monitoring for flaring. Despite readily available monitoring devices and a Consent Decree that addresses excessive flaring at the wood River refinery in the past, it is surprising that the draft permit does not contain requirements for monitoring of flow or composition of waste gas going to the flare. BACT and LAER for flaring necessitate operational monitoring in order to minimize emissions. As monitoring of flaring has been successfully implemented pursuant to applicable regulations at many California refineries, this work provides a ready-made solution for deficiencies in the application for the proposed project, with proven methods that can be included directly into the permit.

In particular, rigorous operational monitoring should be required for flaring as specified by the rules of the SCAQMD and BAAQMD. The Flare Monitoring Rule, Regulation 12-11,[15] which was adopted by the BAAQMD in 2003, shows that issues related to operational monitoring for flaring have been worked out, including verification of gas flow and analysis for hydrocarbons and sulfur content of waste gas. This rule was adopted following input with manufacturers of monitors, refineries and the public. Each requirement of this rule should be incorporated into the permit for the proposed project. These measures are needed for the proposed project due both to the large increase in refinery capacity and the refinery's history of flaring. The Texas Commission on

[15] BAAQMD Regulation 12 Rule 11, http://www.baaqmd.gov/dst/regulations/rg1211.pdf

Environmental Quality also found that accurate emissions data must first be collected in order to then be able to identify and develop options for controlling refinery flaring, which emphasizes the importance of operational monitoring as part of flare emission control.[16] The Shell Martinez Refinery Flare Minimization Plan also emphasized the importance of monitoring.

The issued permit includes an appropriate level of specificity for operational monitoring for flaring. As the fundamental objective for flaring is to minimize and eliminate flaring, it is not appropriate for the permit to include the detailed requirements for operational monitoring present in the BAAQMD's Flare Monitoring Rule. Given the very low level of flaring that should occur in the future at the Wood River refinery, a simpler approach to operational monitoring at the refinery should be established, as compared to the circumstances of the refineries in California that led to the BAAQMD and SCAQMD adopting their Flare Monitoring rules several years ago. Accordingly, the issued permit sets the purposes that must be fulfilled for the operational monitoring for flaring, i.e., *collection of data to* identify when waste gases are flared and in what quantity. The permit does not prescribe what monitoring techniques must be used and how monitoring must be conducted.

75. In 2006, the BAAQMD adopted additional requirements for reporting of flaring at refineries in its rules for Flares At Petroleum Refineries, Regulation 12-12. The provisions of this rule should also be included in the conditions of the permit for the project.[17]

The issued permit includes appropriate provisions for reporting related to flaring. Given the nature of the Illinois EPA's procedures for review of reports from sources, detailed reporting related to flaring associated with this project will be more efficiently and effectively handled if it occurs in conjunction with routine quarterly reporting, rather than as stand-alone reports for significant flaring events. Provisions for prompt reporting upon occurrence of certain flaring events are appropriately set in the *Clean Air Act Permit Program* (CAAPP) permit for the refinery.

76. The monitoring conditions in the draft permit for flaring, which only reiterate federal

[16] TCEQ Master Control Strategy List, Point Sources, page 5, September 7, 2005 http://www.nctcog.org/trans/air/sip/future/lists/TCEQ-oint%20Source%20List.pdf

[17] Reportable Flaring Event: Any flaring where more than 500,000 standard cubic feet per calendar day of vent gas is flared or where sulfur dioxide (SO_2) emissions are greater than 500 pounds per day. For flares that are operated as a backup, staged or cascade system, the volume is determined on a cumulative basis; the total volume equals the total of vent gas flared at each flare in the system. For flaring lasting more than one calendar day, each day of flaring constitutes a separate flaring event unless the owner or operator demonstrates to the satisfaction of the APCO that the cause of flaring is the same for two or more consecutive days. A reportable flaring event ends when it can be demonstrated by monitoring required in Section 12-12-501 that the integrity of the water seal has been maintained sufficiently to prevent vent gas to the flare tip. For flares without water seals or water seal monitors as required by Section 12-12-501, a reportable flaring event ends when the rate of flow of vent gas falls below 0.5 feet per second. http://www.baaqmd.gov/dst/regulations/rg1212.pdf

requirements for monitoring of flares and which were in place in the past when ConocoPhillips had excessive flaring, are vaguely stated.

The monitoring requirements of the applicable federal rules for flaring are appropriately incorporated by the permit by reference to those rules. These requirements address proper operation of a flare for effective destruction of organic constituents in waste gas and effective combustion as related to generation of CO.

77. The Wood River refinery has a major potential for emissions from flaring.[18] Baseline flaring emissions and compressor capacity at the refinery must be provided to the public, and potential increases from flaring must be evaluated in light of this information about other refineries. However, the application did not provide information on existing or waste gas compressor capacity or information on root causes of past flaring at the refinery, or the volume, duration, and emissions of individual flaring events. Without monitoring of the volume and composition of waste gas sent to the flare, and without designing sufficient gas recovery capacity, increased and poorly quantified flaring will occur at existing flares at the refinery with this project.

Under the Consent Decree, ConocoPhillips must prepare and submit its Compliance Plan for Flaring Devices, which will address the existing flares at the Wood River refinery, by December 31, 2007 [Paragraphs 141 and 142 of the Decree]. ConocoPhillips must also use flow meters or reliable flow estimation parameters to determine the emissions from flaring [Paragraph 165].

78. The permit should require ConocoPhillips to develop and implement a flare minimization plan to capture waste gas for use as fuel, rather than flaring it, so that flaring emissions are reduced.

Waste gas is routinely captured for use as fuel rather than being flared. For existing process units, requirements for minimization of flaring are established by the Consent Decree. The Decree requires ConocoPhillips to develop a plan that includes steps to correct the conditions that cause or contribute to excessive Acid Gas Flaring and Hydrocarbon Flaring.

As part of this project, ConocoPhillips will be installing redundant waste gas recovery compressors for the new Delayed Coker Unit, each of which is designed for 100 percent of routine gases from the unit. The issued construction permit also requires ConocoPhillips to develop and implement a Flaring Minimization Plan for the new Coker Unit and the new Hydrogen Plant.

[18] Although it is unlikely that the Wood River refinery performed as well as the average Bay Area refinery before the Bay Area reductions occurred (since USEPA found that excessive flaring was occurring), if the Wood River refinery had performed as well per barrel of crude oil processed, baseline emissions of Total Organic Carbon (TOC) for the refinery would be about 1898 tons per year. Furthermore, the proposed project represents a 126% increase in refinery capacity (306,000 to 385,000 bpd). Flaring emissions will likely increase more than 26% because the refinery is increasing production in the most intensive part of the refinery, with higher-sulfur inputs. With a 26% increase on top of base TOC emissions 1898 tons per year, TOC emissions from flaring at the Wood River refinery would increase by almost 500 tons per year, even using conservative assumptions that could underestimate flaring.

79. What monitoring devices with what detection limits are currently installed to measure flow and composition of waste gases for each existing flare at the refinery? What specific monitoring devices will be installed for the new flares?

The existing flares must be operated to comply with the requirements of the New Source Performance Standards (NSPS) and/or National Emission Standards for Hazardous Air Pollutants (NESHAP) for flares. The NSPS and NESHAP require monitoring for a pilot flame be present in a flare at all times that waste may be sent to the flare, which ensures that any waste gases that are sent to the flare will be ignited and combusted. They do not require other monitoring. Under the Consent Decree, ConocoPhillips must be able to reasonably determine flow and H_2S content of waste gas.

The issued *permit requires that monitoring* and recordkeeping be implemented for new flares to be able to determine flow and composition of waste gas. Use of specific monitoring devices is not required and can be addressed in the processing of a revised Title 5 permit (Clean Air Act Permit Program Permit) to address the proposed project.

80. How many flaring events due to upsets occurred at the Wood River refinery during the last three years.

There were ten events in 2005, ten events in 2006, and four events in 2007. The majority of events occurring in 2005 were attributable to problems with the startup of the gas compressor on the distilling west coker. The majority of events for 2006 were attributable to power outages. Power outages also contributed to events. Power outages affect both the process unit and the waste gas system, as they rely upon availability of electrical power. ConocoPhillips indicates that it is working with Ameren to improve the reliability of the power supply for the refinery.

81. How many flaring events resulted in visual smoking and what evaluations were performed to determine the associated emissions of particulate matter and polycyclic aromatic hydrocarbons?

There were seven events in 2005, seven events in 2006, and one event in 2007. Specific evaluations were not conducted to quantify emissions of particulate matter or polycyclic hydrocarbons. Such evaluation was not considered necessary given the duration of events and the composition of the refinery's waste gas streams, which do not contain significant levels of aromatic hydrocarbons.

82. How much SO_2, VOM, PM, NO_x, CO, and CO_2 is emitted from the existing flares affected by the project? Is that listed somewhere and should it be part of the permit?

Table C-1 of the application contains the baseline annual emissions of CO, NO_x, and VOM for the existing flares affected by the project. The annual emissions, based on

24 consecutive months of actual emission data are: 7.8 tons of CO, 3.6 tons of NO_x, and 3.4 tons of VOM. The emissions of PM and SO_2 were not quantified as they would be minimal given the nature of the gas streams being flared. Historically, emissions of CO_2 from the refinery have not been quantified. The increases in emissions at these flares are addressed in Attachment 1 of the permit.

83. What is the destruction efficiency assumed for calculating flaring emissions and what is the basis of this figure?

For purposes of calculation emissions, properly operated flares are assumed to achieve 98 percent destruction efficiency for VOM and CO contained in the waste gas. This conservative level of performance is based on information on USEPA's *Compilation of Air Pollutant Emission Factors*, AP-42. Actual destruction efficiency could be significantly higher.

84. How much compressor capacity for recovering waste gases is being installed for each of the new flares for the project? What calculations were performed to ensure the compressor capacity will be sufficient to eliminate all routine flaring?

Redundant compressors are being installed on the new coker flare. Each compressor is designed to route 100 percent of the projected flow of waste gas from the coke unit to the fuel gas recovery system.[19] The adequacy of the recovery system in practice will be addressed by the required Flaring Minimization Plan. Other flares which would handle gases from the existing flare gas recovery system are not affected by this project.

CRUDE OIL SUPPLY

85. The proposed project would involve modifications and expansion for the purpose of processing less-expensive, heavier crude oil, with resultant increased local and global pollution and hazards, that will be locked in for decades. The proposed project represents a major new direction in U.S. refinery operations with modifications to process heavy Canadian crude oil recovered from oil sands. This project is a test case of this trend for use of heavier crude oil with higher energy use. Processing of oil sands has impacts in Canada, including degradation of pristine boreal forest and impacts on plants and wildlife Canada. This project requires careful evaluation due to its nature and its long-term implications.

It is beyond the scope of the Illinois EPA's review of the applications for the proposed project to formally consider the various impacts in Canada from the recovery and processing of crude oil from oil sands. This is a matter that is appropriately considered and addressed by the federal and provincial governments of Canada as they regulate this activity. However, as this comment observes, the recovery of crude oil in Canada is accompanied by environmental impacts, as is the

[19] ConocoPhillips indicates that the gas flow rates of process units were modeled at maximum design rates of units plus an engineering safety factor using computer simulation software for petroleum refining processes.

recovery of oil from other locations. These impacts are lowered as the consumption of crude oil is reduced.

86. What evaluations of heavy-metals, such as lead and mercury, in the heavy crude oil have been performed? Will mercury and lead be emitted from the refining process? What measurements are planned for the future for heavy metals in coke to be manufactured and what will be done because of the increase in these heavy metals? What practices will be used to ensure that these increases of heavy metals do not escape into the environment?

Heavy metals, which are present in parts per million and billion levels in crude oil, have not been identified as a special concern for crude oil.[20] Loss of metals to the environment is controlled by the general nature of refining operations and the emission control practices and add-on control equipment implemented for certain units. As an operational matter, there are also production consequences as metals can poison catalysts used in refining operations. USEPA and the American Petroleum Institute are currently engaged in studies on the heavy metal contents in various crude oils, to further improve the understand the relationship between metals in the crude oil supply, the operation of refining units, and the metals content of products and environmental discharges.

87. The heavy crude oil that will be used at the Wood River refinery will be very cheap. ConocoPhillips stands to make a lot of money from this project and it can afford these enhanced environmental controls without sacrificing jobs. Often with increased environmental controls, there might actually be opportunity for more jobs because of the workers that are needed to operate and maintain of these controls.

Heavy crude oil is not cheap. It is only less expensive when compared to lighter crude oil. The lower cost of heavier crude oil is accompanied by additional expenses for investment in the facilities needed to be able to process the heavier material. It is also accompanied by shifts in the amount of different products that can be made and the revenue stream for a refinery. The quality of different products may also be affected so that additional effort may be needed to adapt and enhance certain process units to maintain product quality. As Canada has ratified the Kyoto protocol, the cost of heavy crude from Canada may increase due to the costs of mitigating emissions of greenhouses associated with the extraction and initial processing of crude oil from oil sands. Accordingly, this project is the result of a complex business decision by ConocoPhillips. One of the elements that must go into this business decision is a recognition that the Wood River refinery will have to operate in compliance with environmental requirements, with a workforce that is able to properly operate and maintain environmental control systems. This is an essential aspect of the proposed project irrespective of the cost of compliance.

88. Processing of heavier crude oil (with longer hydrocarbon molecules and higher sulfur content) means more refining to produce gasoline and diesel, and to remove sulfur. This

[20] According to information provide by ConocoPhillips, the lead and mercury content in the expected crude slate is approximately 3 ppm and 7 ppb respectively.

will increase the potential for upset conditions and associated emissions due to the higher temperatures and pressures needed to process heavier crude oil.

The refinery currently processes heavy crude oil, so that the proposed project would not represent a significant change to the overall operation of the refinery. While the project involves installation of a second Delayed Coker Unit to have more capacity to crack the heaviest stream from crude oil, the new cracking units would be designed for this purpose and include appropriate features to maintain safe operation. Accordingly, an increase in upsets should not be expected with the proposed project.

89. ConocoPhillips has applied for authorization to operate during breakdowns when pollution control equipment does not work. This undermines the effective control of emissions, which will be especially important when processing heavier crude oil, which is likely to increase process upsets at the refinery.

ConocoPhillips request for authorization for excess emissions during malfunction and breakdown addressed possible exceedances of a generic state emission standard for SO_2 emissions. Under state rules, ConocoPhillips must obtain "prior authorization" for exceedances of the state standard as it must show that continued operation with excess emissions may be necessary to protect personnel or equipment. This also enables a permit to be prepared with conditions that appropriately address the possibility that such continued operation with excess emissions may occur. However, whether ConocoPhillips actions to avoid malfunctions and reduce emissions in the event of a malfunction are still subject to scrutiny by the Illinois EPA and USEPA as to whether the particular event was avoidable and good air pollution control practices were followed. In contrast, the federal NSPS state that the otherwise applicable standard simply does not apply during malfunctions. The appropriateness of actions taken by a source relative to malfunction are only subject to after-the-fact review as to whether it was avoidable and good air pollution control practices were followed.

DELAYED COKING

90. Coking is a high temperature and pressure process for the heaviest fraction of crude oil handled by a refinery. Emissions of particulate matter, other criteria pollutants, toxic heavy metals, and greenhouse gases can be extreme, especially considering fugitive emissions and accidental releases. These should all have been evaluated. This is especially necessary given the proposed use of crude oil from Canadian oil sands, which is particularly heavy, so this project results in a large amount of coking and energy use. Data on the carbon content of the crude oil supply to the refinery and the range of sulfur, heavy metals, selenium, and other contaminants contained in the crude oil and impacts of these pollutants should have been provided by ConocoPhillips.

Emissions of PSD/NSR pollutants from coking are addressed in the application, including emissions from both routine operation and emergency flaring. Emissions

of heavy metals have not been identified as a particular concern for coking units as fine material is not entrained in a gas stream during the coking process. While USEPA has adopted NESHAP standards for emissions of metal hazardous air pollutants from catalytic cracking and catalytic reforming units, it has not adopted similar NESHAP standards for coking. Moreover, these NESHAP for these catalytic process units set a number of alternative standards that apply either to total particulate emissions or nickel emissions, a single heavy metal. Emissions of greenhouse gases associated with coking are better addressed in terms of the overall energy consumption and emissions of a refinery[21] or in terms of the total emissions of greenhouse gases associated with the crude oil that a refinery processes.

91. An evaluation is needed for the impacts of increased coking at the refinery on wastewater. This is especially true given the planned use of crude oil from Canadian oil sands.

The impacts on the wastewater treatment plant have been addressed by the air permit as further shown in Section 4.10 of the permit. The wastewater treatment plant will require modifications to accommodate an increase in wastewater flow and solids and organic loading due to increased refining operations and to treat the wastewater from the scrubbers on the FCC Units. These modifications will have emission consequences and are appropriately limited by this section of the permit.

92. An evaluation is needed for the impacts of increased coking at the refinery on soil contamination. This is especially true given the planned use of crude oil from Canadian oil sands.

This project should not contribute to soil contamination at the refinery. Soil contamination at refineries is generally the result of historic refinery design and operating practices. As such spills occurred, lighter materials typically are of particular concern for contamination. As spills of material now occur at the refinery with the potential for soil contamination, such spills must be investigated and either remediated or appropriately contained pending remediation in the future.

93. Because of employee accidents associated with Delayed Coker Units, a Chemical Safety Alert (Hazards of Delayed Coker Unit (DCU) Operations, August 2003) was jointly issued by USEPA, the Occupational Safety and Health Administration (OSHA), the U.S. Department of Labor, and the Chemical Emergency Preparedness and Prevention Office. This alert found that Delayed Coker Units are increasing in use due to their ability to process lower quality crude oil, as higher quality crude becomes less available to refiners. The alert found that these units have hazards that must be addressed by the operators of the units, listing the various process steps and the specific hazards that are posed.

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[21] The quantity and quality of the intermediate streams produced by an initial conversion process, like coking, has implications for the amount of energy consumed by downstream process units at a refinery. The product slate of a refinery is also relevant for a meaningful assessment of the energy efficiency of a refinery.

While this Chemical Safety Alert identified potential safety hazards for workers from delayed coking units, it also described actions that could be taken to minimize those risks. ConocoPhillips indicates that the new Delayed Coker Unit is being designed with features, such as mechanical interlocks and an automated remote drum unheader, to address the dangers that may be posed by older coker unit and help prevent accidents. Similar upgrades are planned for the existing coker unit during a future maintenance turnaround at the refinery. In the meantime, a manual safety procedure involving multiple signatures as cross-checks is being used to prevent incidents. That procedure was enhanced this spring and ConocoPhillips indicates that it has been very effective. The Illinois EPA will be examining the effectiveness and the adequacy of the measures currently being implemented by ConocoPhillips and the measures that are planned. This will occur as part of the Illinois EPA's investigation into recent releases that have occurred from the existing coker unit at the refinery.

94. The new coking unit, which will process the heavy crude, is going to produce petroleum coke. Given USEPA's and Illinois' new rules on mercury emissions from coal fired power plants, what will ConocoPhillips do with the petroleum coke if power plants can not use it? Do all the coal-fired power plants around use it or just a few or some?

There is no reason to believe that coal-fired power plants will no longer use petroleum coke from the refinery. Additionally, the market that the refinery chooses to sell products to has no impact on its ability to comply with the applicable regulations.

Incidentally, the new coker will not directly process heavy crude oil. The function of the new coker unit is to further process more of the bottom fraction of crude oil, which is currently produced at the refinery and sold as asphalt. The coker unit will convert this bottom fraction into petroleum coke, a solid fuel material, and a liquid stream that can be further processed into higher value petroleum products.

95. I am concerned about coking because of past releases from the coker units at the refinery, which released material that caused damage to homes and property. As part of this project, is ConocoPhillips taking into consideration that according to an August 2003 document prepared by the USEPA and OSHA, delayed coker units have been found to cause frequent and severe accidents. Considering the past violations at the refinery, will employees be safe and nearby residents be safe given the hazards associated with these units? What steps will be taken to ensure the safety of employees?

The past releases appear to have been caused by operator error. As part of this project, safety interlocks will be installed on the new coking unit to prevent similar releases from the new unit. ConocoPhillips indicates that the new coker unit will have all of the latest safety features for a coking unit, including automated equipment, interlock valves, enhanced instrumentation and other safety systems.

96. What measures have been evaluated to eliminate fugitive dust from coking during the

manufacture, storage and transportation of petroleum coke due to the project? Have there been recent violations at the refinery involving these operations.

With appropriate housekeeping practices, the handling of petroleum coke is not a significant source of fugitive dust. The coke is cut out of the coke drums with water jets, which wets the surface of the coke preventing dusting. Thereafter, fugitive dust can be readily controlled by appropriate handling practices with application of additional water or other dust suppressant as needed to control fugitive dust. Given these circumstances, the handling of coke by ConocoPhillips has not posed any concerns for compliance.

EMISSIONS

97. A full evaluation is needed for emissions $PM_{2.5}$ from the project, including secondary formation of $PM_{2.5}$ caused by SO_2 and NO_x emissions from the project.

The general effect of the changes occurring at the refinery, including the proposed project, is to reduce its contribution to the levels of $PM_{2.5}$ in the ambient air and to improve air quality. This is because the net effect of these changes is to reduce emissions of direct PM. Emissions of precursors to $PM_{2.5}$ are also reduced as emissions of emissions of SO_2 are substantially reduced. (Emissions of NO_x would not increase significantly, even with the permitted increase in production.)

As the Greater St. Louis area is currently designated nonattainment for $PM_{2.5}$, the Illinois EPA and the Missouri Department of Natural Resources must develop and implement attainment plans to bring the area into attainment of the National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$. This will provide a comprehensive evaluation of local and regional emissions of direct $PM_{2.5}$ and precursors to $PM_{2.5}$, including emissions from the Wood River refinery, as necessary to assure that the compliance of the NAAQS for $PM_{2.5}$ is achieved and maintained throughout the area.

98. This provision of the Consent Decree purporting to allow use of emission reductions as part of projects at the refinery is contrary to the Clean Air Act and thus invalid.[22] Section 173(c)(2) of the Clean Air Act expressly prohibits the use of emissions reductions required by the Act as offsets. ConocoPhillips cannot be allowed to use emission reductions required by the Consent Decree as offsets for this project because these reductions are required by the Clean Air Act.

Section 173(c)(2) of the Clean Air Act, which deals with emission offsets for major projects in nonattainment areas, is not relevant to the permitting of the proposed project for emissions of SO_2. Not only will the proposed project occur in an

[22] Paragraph 262(d) of the Consent Decree provides that "...utilize emissions reductions from the installation of controls required by this Consent Decree in determining whether a project that includes both the installation of controls under this Consent Decree and other construction that occurs at the same time and is permitted as a single project triggers major New Source Review requirements.;"

attainment area for SO_2, and not in a nonattainment area, but the decreases in SO_2 emission are being used for purposes of "netting" to demonstrate that the proposed project is not a major project. The emissions decreases are not being used as emission offsets, which would entail a transfer of emission reduction credits from one source to another, as is occurring for the proposed project for emissions of VOM.

99. If the emission decreases from the installation of scrubbers on the FCC Units were not credited against the proposed project, the project would have a significant increase in SO_2 emissions and be a major modification for emissions of SO_2 under the PSD rules. The addition of the scrubbers to the FCC Units results in decreases in SO_2 emissions of 5,909.6 tpy from FCC 1 and 5,221.9 tpy from FCC 2 (total 11,132 tpy). If these decreases were not credited towards the project, the project would have a net SO_2 decrease of only 36 tpy.[23] When increased SO_2 from flaring, missing from the application, are included, hundreds of tons per year more emissions are added with the proposed project. While these emissions can be prevented with BACT for new and existing flares that will handle the additional waste gases due to the proposed project, the project would increase SO_2 emissions by more than 40 tpy as currently proposed. This triggers PSD for emissions of SO_2, requiring BACT for emissions of SO_2 from new and modified emission units.

As this comment confirms, at most only a fraction of the decrease in SO_2 emission from the installation of scrubbers on the FCC Units is needed to ensure that the proposed project is not a major project for emissions of SO_2. Accordingly, assuming for purposes of argument that even most of the decrease in SO_2 emissions from installation of scrubbers on the FCC Units could not be relied upon for the permitting of the proposed project, the remaining decreases would still be sufficient for the project not to be a considered a major modification for emissions of SO_2.

In addition, the refinery is subject to requirements, as touched upon by this comment, that act to prevent increases in SO_2 emissions due to increased flaring at existing flares in conjunction with this project. In particular, the Consent Decree includes requirements to investigate the cause of flaring incidents that contribute to SO_2 emissions, including performance of root cause analysis, to take steps to correct the conditions that cause such incidents, and to minimize the number and extent of such incidents. These requirements are accompanied by provisions for detailed reporting for significant flaring incidents with estimates of SO_2 emissions, the root cause analysis and the corrective action plan. Stipulated penalties apply if an incident resulted from careless operation, failure to operate in accordance with good engineering practice, or failure to follow written procedures. A condition has been included in the issued permit that makes clear that these practices, other than stipulated penalties, are also applicable for the new flare that would be installed with the new Delayed Coking Unit.

100. In order to clearly evaluate the proposed project and alternatives, the project should be assessed without the SO_2 emission decreases from the scrubbers on the FCC Units

[23] 11,168 tpy - 11,132 tpy = 36 tpy

(11,132 tons), which are not allowable under the Clean Air Act, and separately from offsets from other projects (3,165 tons). In this light, the proposed project by itself will result in an annual SO_2 emissions increase of 3,129 tons.

This comment reflects an incorrect evaluation of the proposed project for emissions of SO_2. The project is only being permitted for 1548 tons per year of "new" SO_2 emissions. The project also will only be accompanied by an emissions decrease of 1,554 tons per year from other contemporaneous projects. However, these decreases by themselves would still be sufficient for the project to net out of PSD review for emissions of SO_2. The installation of the scrubbers on the existing FCC Units will provide a further decrease in emissions of SO_2 of at least 11,132 tons per year. In summary, there will be a substantial decrease in refinery's SO_2 emissions from current levels after the proposed project is complete. These circumstances do not necessitate an alternative formulation of the extent of those decreases to assess the effect of the project or consider *alternatives to the proposed project.*

101. To the extent the decreases in SO_2 emissions listed for other "Contemporaneous" projects were or will be carried out pursuant to the Consent Decree or are otherwise required by the Clean Air Act, they are not allowable for offsets. The Illinois EPA must provide a detailed evaluation of this issue and historical review of reasons for these contemporaneous projects in order to address the potential improper use of offsets by ConocoPhillips for this project.[24]

The emissions decreases for Contemporaneous Projects are itemized in Table C-12 of the application. These decreases occurred with and were relied upon for other projects at the refinery. Their circumstances of these past decreases are identical to the future emissions decreases that will occur at the FCC Units with installation of scrubbers. Incidentally, the amount of these decreases is only about 1,580 tons.

102. The current SO_2 emissions of the Wood River refinery are very high compared to those of refineries in Texas and California. The touted 11,168 ton reduction in annual SO_2 emissions that will accompany the proposed project is long overdue and is improperly being used to cover up the increases in SO_2 emissions that actually result from the proposed project, when SO_2 emissions should have been reduced separately, on its own merits. For example, the baseline annual SO_2 emissions of the Wood River refinery, with a current capacity of about 306,000 bpd, are about 11,468 tons, which is almost 8 times higher than the emissions of BP's South Coast refinery when adjusted for capacity.[25]

Emission of SO_2 should not be compared as simply as suggested by this comment.

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[24] Appendix C of the application shows the total use of 3,165 tpy of SOx offsets, i.e., 1,580 tpy of offsets from contemporaneous projects of at startup of "FCCU-3 and DU-2 LC Startup" and 1,585 tpy of additional offsets when the project is completed.

[25] In 2005, the average SO_2 emissions reported for the 28 refineries in Texas were 1,985 tons, for a total 52,868 tons. In 2005, the average SO_2 emissions for the five refineries in the San Francisco Bay Are were 2532 tons, for a total of 12,662 tons. In the South Coast area (Los Angeles area), the average SO_2 emissions of seven refineries were 683 tons, for a total of only 4779 tons. The largest capacity California refinery, the BP South Coast refinery with a capacity of 260,000 barrels per day (bpd), emitted only 1221 tons of SO_2 in 2005.

This is because of the various factors that affect SO_2 emissions of a refinery. These factors include location and access to different sources of crude oil, the nature of crude oil that a refinery is capable of processing, the nature of the refining processes at the refinery, age of the units at a refinery, and a number of other factors.

103. The total SO_2 baseline emissions of the Wood River refinery are not provided in the application (Table C-1, proposed Project Emission Increases Summary, Appendix C 5)[26] There may be additional significant SO_2 emissions from facilities at the refinery that are not included in this listing, which should be provided to the public as part of the application and for consideration of alternatives to the project.

The application was appropriately prepared to address the existing emission units at the refinery that are affected by the proposed project. Information on the total baseline emissions of SO_2 of the Wood River Refinery is available from the Annual Emission Reports submitted by ConocoPhillips for 2004 and 2005, which indicate annual SO_2 emissions of about 12,500 tons. It is not necessary to include data in the application for baseline emissions for existing units that are not affected by this project. In fact, the majority of the emissions of the refinery are addressed in the application, since the project includes changes at existing process units at the start of the refining process.

104. Even after the emissions decreases with the project are achieved, with control of SO_2 emissions of the FCC Units, the total annual SO_2 emissions for the various operations at the Wood River refinery listed in the application are 1891 tons (Appendix C Table C-1). This Table does not provide total SO_2 for all refinery units, only emissions from the units in the project, so the total for the refinery may be even higher. When compared to the average SO_2 emissions for refineries in other regions, the Wood River refinery will still have more SO_2 emissions than the typical refinery in Texas, (1786 tpy)[27] or California (1,607 tpy). It will also have higher emissions than the largest California refinery (BP with 1,221 tpy). Accordinglly, the Wood River refinery cannot be considered to provide the best control for emissions of SO_2, or even the average rate of control, after the proposed project.

It is wholly inappropriate to compare the future <u>permitted</u> SO_2 emissions of the Wood River refinery, as set by the permit, to the <u>actual</u> emissions of other refineries. The permitted emissions of the refinery, as set by the permit, incorporate safety factors to account for normal variation in the operation of processes and control measures as related to emissions. After the proposed project is completed, it is expected that the actual SO_2 emissions from the Wood River refinery will consistently be significantly lower than the permitted emissions, with actual SO_2

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[26] The total of emissions listed for the units at the refinery after the project in Appendix C, Table C-1 is not provided, only the change in emissions. However, the column entitled "Potential/Projected Actual Emission Rate (tons/yr)" provides emissions expected after the CORE Project for individual units, which totals on the Table to 1891 tons/yr.

[27] The refinery in Texas that emitted 11,786 tons of SO_2 in 2005 is not typical and is an outlier compared to the other Texas refineries.

emissions that coincidentally are equal to or less than the "average" refineries discussed in this comment.

The actual SO_2 emissions of other refineries are also not indicative of the amount of SO_2 emissions that those refineries are allowed to emit by applicable emissions standards and permits. Accordingly, their actual SO_2 emissions do not provide a meaningful reference for whether the SO_2 emissions of the Wood River refinery would be well controlled in the future. In this regard, the Consent Decree, which addresses existing emission units, and the federal New Source Performance Standards, which will address new and modified units at the refinery, can be considered to require very good control of the SO_2 emissions of the refinery in the future.

105. The decreases in the SO_2 emissions of the FCC Units are required by a Consent Decree with the USEPA, the State of Illinois and other states that address the Wood River refinery and other refineries operated by ConocoPhillips.[28] Therefore ConocoPhillips cannot take credit for these decreases for permitting the proposed project. In particular, the Consent Decree requires ConocoPhillips to install certain emission controls at the Wood River refinery, including scrubbers on the FCC Units, which provide most of the SO_2 emissions decreases. The Consent Decree also states that ConocoPhillips may not take credit for reductions required by the Consent Decree.

The provisions of the Consent Decree with respect to "use" of emission reductions are more involved that indicated in this comment. The ability of ConocoPhillips to use emissions decreases that result from actions under this decree is a matter that is addressed by the actual terms of the Consent Decree, which allow use of the emission decreases for permitting of the proposed project. (Paragraph 262(d) of the Consent Decree). The provisions of the Consent Decree that address use of emission decreases were negotiated by ConocoPhillips, the USEPA and other parties to the Decree, as the Decree constitutes a negotiated settlement of alleged violations on the part of ConocoPhillips.

106. The SO_2 limits for the FCC Units proposed in the draft permit do not represent BACT and should be lower. The draft permit would require the FCC Units to meet limits of 25 ppmvd SO_2, 365-day rolling average, and 50 ppmvd, 7-day rolling average, both at 0% O_2, pursuant to Paragraphs 57 and 60 of the Consent Decree. A study by the USEPA, the University of Texas, and the Texas Commission on Environmental Quality reviewing the emission rates achieved in practice found that the Valero refinery in Corpus Christi, Texas met a 20 ppm limit in 2003. This limit should be required for this project.

This comment does not support setting lower SO_2 limits for the FCC Units. The proposed project does not trigger a requirement for BACT for emissions of SO_2. In addition, these comments suggest that a stringent level of control for SO_2 emissions

[28] 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)

is already required by the Consent Decree. The study cited by this comment shows actual SO_2 emissions at 20 ppm in a particular year, which is consistent with an emission limit set at 25 ppm, to provide a safety factor for normal variation in operation of an FCC Unit and its SO_2 emission control systems.

107. It is not clear whether there is a net reduction in emissions from this project, as ConocoPhillips claims. With all of the netting and all of the debottlenecking and all of the problems that are involved, there is going to be an increase in emissions. I don't want the netting to be "smoke and mirrors." I want there to be an actual decreases in emissions.

The project will result in a net increase in emissions of some regulated pollutants (e.g., VOM, CO, and PM). For pollutants for which there is net decrease in emissions(e.g., NO_x and SO_2). In order for emissions decreases to be considered creditable for purposes of a netting exercise, they must be actual decreases in emissions.

108. What will be the increase in emission of H_2S from the proposed project, in pounds, from both the Wood River and the Distilling West facilities?

There will be at most a minimal increase of H_2S as a result of this project. Most of the H_2S and other sulfur compounds will be recovered by the new sulfur recovery units as elemental sulfur. The H_2S in the tail gas from the Sulfur Recovery Units is converted to SO_2 in the oxidizers. The H_2S in the fuel gas system will be converted to SO_2 through combustion in the heaters or other combustion devices.

109. An evaluation is needed for emissions and impacts of the project on the public from odors, including odors due to flaring, fugitive H_2S emissions from higher sulfur products at the refinery, and other sources of emissions.

This project will not be significant for emissions of H_2S. This is because streams with potentially significant levels of emissions of H_2S will be combusted, either as fuel gas or by flaring, converting the H_2S to SO_2. Overall, the emissions of H_2S from the refinery should be decreasing because of improvements being made pursuant to the Consent Decree.

OTHER

110. The D.C. Circuit Court recently vacated the Boiler MACT Rule, which means there is no industry standard and permits require individual MACT analyses for any boilers that were subject to this rule.[29]

While the D.C. Circuit Court recently issued an order finding that the "Boiler MACT Rule" should be vacated, the Circuit Court has not yet issued a final mandate to vacate this rule. In the interim, the Boiler MACT Rule remains in

[29] http://pacer.cadc.uscourts.gov/docs/common/opinions/200706/04-1385a.pdf.

effect. When and if a final mandate is issued, the Illinois EPA would proceed as instructed by USEPA for this unusual development with respect to this rule. This could necessitate ConocoPhillips having to obtain a revised construction permit for the boilers and steam generating units that would have otherwise been subject to the Boiler MACT Rule. A case-by-case MACT determination might also have to be made through an appropriate revision of the CAAPP permit for the refinery, so as to address existing boilers at the refinery, independent of the proposed project.

111. How many pressure-relief devices at the refinery vent to the atmosphere and what monitoring devices are used to determine whether these devices have vented? How many pressure-relief devices from the new project will vent to the atmosphere? What monitoring devices will be used to determine whether they have vented?

While many of the pressure relief devices vent to the existing vent gas recovery system, which routes discharges to the fuel gas system, there are certain pressure relief valves that vent directly to the atmosphere to protect equipment and workers from catastrophic failure. There are no new hydrocarbon pressure relief valves as part of the proposed project. Pressure relief valves are recognized as potential sources of emissions due to leaks and are addressed by the Leak Detection and Repair (LDAR) program that ConocoPhillips must implement under state and federal rules. For pressure relief valves, this program requires measurements with a portable organic vapor analyzer whenever a valve opens. These measurements are used to confirm that the valve has properly resealed after the event was over or that the new rupture disk was properly installed over the pressure relief valve.

112. Will the valves for the proposed project be leakless bellow valves? How many new compressors and pumps will have double seals and how many will not?

ConocoPhillips is not planning to use bellow valves. Bellows valves and certain other "leakless" equipment can have significant emissions when failures occur. In particular, bellow valves are not reliable in "aggressive" service. This type of equipment is also not available for all situations in refinery operations.

All new pumps in light liquid service in the new units will be equipped with double seals. It is anticipated that the definition for a leak set as LAER could be met with control technologies such as dual or mechanical seals.

113. Has the Illinois EPA analyzed how the proposed changes to federal New Source Performance Standards (NSPS) for petroleum refineries, which will be applicable to this project, affect the permit?

Many of the amendments and new rules[30] were driven by the control technologies required by USEPA's New Source Review Consent Decrees for various refineries. Although these rules are not expected to be adopted until 2008, the proposed project

[30] On April 30, 2007, the USEPA proposed amendments to the current NSPS for Petroleum Refineries (40 CFR 60 Subpart J) and a new NSPS for units including FCC units, coking units, and sulfur plants. (40 CFR 60, Subpart Ja).

will be designed comply with these new and revised NSPS standards, which are consistent with the stringent emission limits set in the ConocoPhillips Consent Decree.

114. The Endangered Species report submitted by ConocoPhillips is inadequate because they used what appears to be an inappropriate model for the deposition modeling and the follow-up evaluation – using one for hazardous waste incineration facilities rather than for the refining of crude oil from Canadian tar sands. In addition, the data used in the model appears to for the existing supplies of crude oil.

The analysis for impacts of the proposed project on threatened and endangered species was properly prepared. Deposition modeling was conducted with an appropriate model. While the specific model was originally developed to address deposition associated with hazardous waste incineration, it is also suitable for addressing deposition of emissions from other types of sources. This is because there is nothing unique about how deposition occurs from a hazardous waste incinerator as compared to how deposition occurs from other types of sources. The data used in the analysis that reflected "current" composition of certain emissions was appropriate given the very conservative nature of the particular data. In addition, the analysis showed very low potential impacts so that the precision of this data was not a critical element for the conclusion of the analysis.

Existing Groundwater Contamination

115. Will the cone of depression under our towns get larger with the additional groundwater that will be pumped and used for the proposed project?

The proposed project will not expand the cone of depression as the pumping rate will not increase with this project. The cone of depression is the intentional result of actions taken to prevent the migration of existing soil contamination under certain areas of the refinery. By pumping groundwater from under the refinery and maintaining a cone of depression, groundwater flows toward the refinery, rather than away from the refinery, which prevents the spread of contamination. Collected groundwater is then treated to remove contamination.

116. Is there a reason that that contamination is not being remediated in another way instead of just pulling the water down far enough so it is not coming into contact with contaminated soil? Given ConocoPhillips stated goal of protecting the local community and the environment, it should find another approach to the contamination instead of wasting this much groundwater, which could be otherwise be used for productive purposes.

Equilon Enterprises LLC d/b/a Shell Products US is required by a RCRA permit issued by the Illinois EPA, Bureau of Land to maintain a gradient control under the refinery. This is done by maintaining a cone of depression that prevents contamination from migrating off-site. ConocoPhillips is maintaining the cone of depression for Equilon, as it is required to do under a contract with Equilon. When

the RCRA permit was issued, this approach was determined to be an acceptable approach for containing contamination. This approach is both feasible and cost-effective as it does not disrupt the operation of the refinery. The groundwater that is pumped is productively, as it is one of the sources of water for the refinery

117. How is the groundwater contamination in the Hartford area, where a layer of oil floats on the top of groundwater, being addressed?

The groundwater contamination in the Hartford area is being remediated by the Hartford Working Group under an Administrative Order on Consent from USEPA (No. R7003-5-04-001). The Hartford Working Group is a consortium of the companies that have been found to be responsible for this contamination and are subject to this Order. ConocoPhillips is not one of these companies.

Compliance

118. It is the responsibility of the Illinois EPA to review and grant the construction permit not only for what complies with the Clean Air Act and Illinois' regulations but also how it impacts the people who live here. The Illinois EPA has discretion. The Illinois EPA can be permissive and relax requirements or it can require the best technologies and actual pollution reductions. The Illinois EPA can require strict controls and monitoring and can enforce compliance and prosecute violations.

The Illinois EPA's action on the application for the proposed project is constrained by applicable laws and regulations. The Illinois EPA does not have the authority to relax requirements as suggested by this comment. Likewise, the Illinois EPA does not have the authority to arbitrarily set requirements for control of emissions that are more stringent than allowed under applicable regulations and permitting programs. The Illinois EPA has used the discretionary authority that it does possess to set stringent requirements for the proposed project, accompanied by rigorous requirements for monitoring. The Illinois EPA also enforces compliance and, with the assistance of the Office of the Attorney General, prosecutes violations.

119. The Wood River Refinery has a history of noncompliance with environmental regulations as does ConocoPhillips. ConocoPhillips was sued by the USEPA and the State of Illinois for violating the Clean Air Act. It is the subject of a Consent Decree that requires it to do certain things by certain dates so that their facilities comply with the law. It has asked for more time to comply with certain requirements.

The request for extension does not apply to the Wood River refinery. ConocoPhillips has requested for some of its other refineries that were affected by a hurricane, which prevented them from meeting the schedule in the Consent Decree.

120. The proposed project requires evaluation of the commitment of ConocoPhillips to clean up emissions of the refinery due to past violations independent of this expansion.

ConocoPhillips has been fulfilling its obligations under the Consent Decree to resolve alleged emission violations at the Wood River refinery.

121. ConocoPhillips was out of compliance wit the Clean Air Act for the last twelve quarters.

The ECHO database does indicate that the refinery has allegedly been out of compliance with the Clean Air Act. However, the Illinois EPA is not aware of current violations of applicable air pollution control laws or regulations. It is believed that the noncompliance that underlies the data in the ECHO database is historic noncompliance, which has been legally resolved with the Consent Decree.

Public Participation

122. It has been my experience with other public hearings on construction permit applications that I ask questions at the hearing, and if the Illinois EPA staff does not know the answers, then I don't get the answers until after it is all over. I have no opportunity to comment on the answers. The Illinois EPA should find some way of putting the answers on the record so that I can then submit and extend the comment period so I can comment on the answers. I do not expect all the answers to be available at a public hearing, but it would be very helpful if I would be able to have the answers and then be able to comment on them.

The procedures for public comment periods and public hearings do not accommodate the continuing exchange or dialog on draft construction permits requested by this comment. The Illinois EPA staff responds to questions at public hearings on construction permits as it is able to do so. However, the primary purpose a public comment period, including a public hearing is to obtain input from the public on the Illinois EPA's preliminary decisions that a proposed project is entitled to a construction permit.

123. More detailed data must be provided by ConocoPhillips, rather than requiring the public to effectively provide the analysis by pulling together this information. An evaluation is needed for many of the issues raised at the public hearing that were not answered at the hearing. The public brought up key environmental and health issues and questions about basic data and impacts of the project. The transcript shows that many of these issues were not evaluated. There should be a follow-up on all questions evaluated.

This Responsiveness Summary provides the Illinois EPA's follow-up to the various issues and questions raised at the hearing and in written public comments. As explained in response to various comments, comments did not identify issues that required submittal of more data or performance of additional analyses by ConocoPhillips.

124. There are many additional clear hazards from this project, but the application failed to provide basic information for public analysis, and the time for public review was short considering the fact that the public had to assemble much basic data. The Illinois EPA

should re-evaluate the project taking into account these additional issues and re-open the comment period.

The public comment period, which lasted over 80 days, provided a reasonable amount of time for the public to review the application for the proposed project and submit informed comments. The public comments do not raise any issues whose nature is such that they warrant preparation of a new draft permit by the Illinois EPA and re-opening of a public comment period. While various concerns are raised about the proposed project, the comments do not show that the project, as currently proposed by ConocoPhillips, would pose significant hazards to the public or should not be permitted.

Other Comments

125. Fuel efficiency standards for vehicles need to be increased. We also need to move past fossil fuels and develop electric cars and wind and solar energy. As Senator Obama has stated, for the sake of our security, our economy, our jobs and our planet, the age of oil must end in our time.

126. There are a lot of health problems in this area. Many of our children have asthma. We do not need any more particulate matter or ozone in the air.

127. ConocoPhillips should operate its heating and cracking units more efficiently.

128. It is important to work to devise credible, practical, cost-effective approaches to address the emissions of greenhouse gases at the national and at the international level, given the global nature of climate change. ConocoPhillips should strive to do this for this project.

For Additional Information

Questions about the public comment period and permit decision should be directed to

Bradley Frost, Community Relations Coordinator
Illinois Environmental Protection Agency
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1021 North Grand Avenue, East
P. O. Box 19506
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CONSTRUCTION PERMIT - NESHAP SOURCE - NSPS SOURCE - PSD APPROVAL

PERMITTEE

ConocoPhillips Company
Attn: Tom Wynn
1000 South Pine, 5540 CB
Ponca City, Oklahoma 74602

Application No.: 06110049
I.D. No.: 119050AAN
Applicant's Designation:
Date Received: November 27, 2006
Subject: Terminal Expansion
Date Issued: July 19, 2007
Location: 2150 South Delmar Avenue, Hartford

This Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source(s) and/or air pollution control equipment consisting of a terminal expansion, that is, modifications to the existing petroleum product terminal to accommodate the neighboring Wood River Refinery's CORE project, 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.
Acting Manager, Permit Section
Division of Air Pollution Control

Date Issued: ____________________

ECB:JMS:psj

cc: Region 3
Lotus Notes
CES

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 – (217) 782-3397
JAMES R. THOMPSON CENTER, 100 WEST RANDOLPH, SUITE 11-300, CHICAGO, IL 60601 – (312) 814-6026

ROD R. BLAGOJEVICH, GOVERNOR   DOUGLAS P. SCOTT, DIRECTOR

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1.0 LIST OF ABBREVIATIONS AND ACRONYMS COMMONLY USED

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
CORE	Coker and Refinery Expansion Project
F	Fahrenheit
FCCU	Fluidized Catalytic Cracking Unit
HAP	Hazardous Air Pollutant
hr	Hour
IAC	Illinois Administrative Code
I.D. No.	Identification Number of Source, assigned by Illinois EPA
Illinois EPA	Illinois Environmental Protection Agency
Kg	Kilogram
LAER	Lowest Achievable Emission Rate
Lb	Pound
Mg	Megagram
MACT	Maximum Achievable Control Technology
Mo	Month
m^3	Cubic meters
mg/L	Milligrams per Liter
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
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
SO_2	Sulfur Dioxide
USEPA	United States Environmental Protection Agency
VCU	Vapor Combustion Unit
VOC	Volatile Organic Compounds (synonymous with VOM)
VOM	Volatile Organic Material
Yr	Year

2.0 FINDINGS

2.1 a. ConocoPhillips has requested a permit for modifications to the existing petroleum product terminal that are required to accommodate the Wood River Refinery's proposed CORE (Coker and Refinery Expansion) project. A separate construction permit application (Application Number 06050052) has been submitted for the changes at the refinery. 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. 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 and NA NSR.

2.2 The petroleum product terminal 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 project 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 5b.)

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 3.3.1 (storage tanks with increase in utilization).

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. 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 modifications to the existing petroleum product terminal are required to accommodate the Wood River Refinery's proposed CORE (Coker and Refinery Expansion) project. The following are the key elements of the proposed modification:

- One new gasoline tank;
- Two new ethanol tanks;
- Two new distillate tanks;
- Expansion of the existing truck loading rack;

The key elements discussed above and other changes made as part of this project are further addressed in unit-specific conditions (see Section 4.1 through 4.4).

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.

3.2.3 Emissions Offsets

a. The Permittee, either alone or coordinated with ConocoPhillips' Wood River Refinery, 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.

COMPANY NAME, I.D. No.
Permanent Shutdown of Facility 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 this 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 State Rules for Gasoline Distribution

Gasoline loadout operations at this terminal are subject to 35 IAC 219 Subpart Y, which provides that:

a. No person shall cause or allow the transfer of gasoline into any delivery vessel from any bulk gasoline terminal unless [35 IAC 219.582(a)]:

i. The bulk gasoline terminal is equipped with a vapor control system that limits emission of VOM to 80 mg/1 (0.00067 lbs/gal) of gasoline loaded;

ii. The vapor control system is operating and all vapors displaced in the loading of gasoline to the delivery vessel are vented only to the vapor control system;

iii. There is no liquid drainage from the loading device when it is not in use;

iv. All loading and vapor return lines are equipped with fittings which are vapor tight; and

v. The delivery vessel displays the appropriate sticker pursuant to the requirements of 35 IAC 219.584(b) or (d); or, if the terminal is driver-loaded, the terminal owner or operator shall be deemed to be in compliance with 35 IAC 219.582 when terminal access authorization is limited to those owners and/or operators of delivery vessels who have provided a current certification as required by 35 IAC 219.584(c)(3).

b. The operator of a bulk gasoline terminal shall [35 IAC 219.582(b)]:

i. Operate the terminal vapor collection system and gasoline loading equipment in a manner that prevents:

A. Gauge pressure from exceeding 18 inches of water and vacuum from exceeding 6 inches of water as measured as close as possible to the vapor hose connection; and

B. A reading equal to or greater than 100 percent of the lower explosive limit (LEL measured as propane) when tested in accordance with the procedure described in EPA 450/2-78-051 Appendix B, incorporated by reference in 35 IAC 219.112; and

C. Avoidable leaks of liquid during loading or unloading operations.

ii. Provide a pressure tap or equivalent on the terminal vapor collection system in order to allow the determination of compliance with 35 IAC 219.582(d)(1)(A); and

iii. Within 15 business days after discovery of the leak by the owner, operator, or the Agency repair and retest a vapor collection system which exceeds the limits of 35 IAC 219.582(c)(1)(A) or (B).

c. The Permittee shall comply with the applicable gasoline delivery vessel requirements and gasoline volatility standards in 35 IAC 219.584 and 219.585, respectively.

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 that was filed on January 27, 2005.

3.3 Source-Wide Non-Applicability of Regulations of Concern

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 source 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 gasoline and distillate as a consequence of the CORE project of at most 6.7 tons/year (Refer to Condition 4.2.6(a)(ii)).

3.3.2 NESHAP

This permit is issued based on the terminal being operated by the distribution division of ConocoPhillips Corporation, so that it is subject to the NESHAP for Gasoline Distribution Facilities, 40 CFR 63 Subpart R (Refer to Gasoline Distribution Industry (Stage I) - Background Information for Promulgated Standards, USEPA, November 1994, EPA-453/R-94-002b, PB 95-170346, page 3-18).

Note: If the terminal were managed by the same personnel as the refinery, the terminal would be subject to the NESHAP for Refineries, 40 CFR 63 Subpart CC.

3.4 Source-Wide Production and Emission Limitations

None.

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 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 terminal's maximum capacity from the CORE project (gallons/month).

ii. Emissions of VOM attributable to the increase in throughput (tons/month and tons/year).

3.6 <u>Plant-Wide Reporting Requirements</u>

3.6.1 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 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.

B. Control equipment information.

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 Loading Rack

4.1.1 Description

The existing loading rack will be physically modified by adding loading bays/arms. The rack will continue to load petroleum products and various gasoline feed stocks into trucks. A new loading rack control device (e.g., vapor combustion unit (VCU)) will be installed to control VOM emissions from the loading rack.

4.1.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
EP-1	Modified Loading Rack	VCU*

* Or a similar control device capable of achieving an equivalent level of control.

4.1.3 Applicable Provisions and Regulations

a. The "affected unit" for the purpose of these unit-specific conditions, is the loading rack described in Conditions 4.1.1 and 4.1.2.

4.1.3-1 Applicable Federal Standards (40 CFR 63, Subpart R)

The affected unit is subject to 40 CFR 63, Subpart R: National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), which provides that:

a. Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of Subpart R shall comply with the requirements in 40 CFR 60.502 except for 40 CFR 60.500(b), (c), and (j). For purposes of 40 CFR 63.422, the term "affected facility" used in 40 CFR 60.502 means the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart [40 CFR 63.422(a)].

b. Emissions to the atmosphere from the vapor collection and processing systems due to the loading of gasoline cargo tanks shall not exceed 10 milligrams of total organic compounds per liter of gasoline loaded [40 CFR 63.422(b)].

c. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall comply with 40 CFR 60.502(e) as follows [40 CFR 63.422(c)]:

i. For the purposes of 40 CFR 60.502, the term "tank truck" as used in 40 CFR 60.502(e) means "cargo tank."

ii. 40 CFR 60.502(e)(5) is changed to read: The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline cargo tank will not be reloaded at the facility until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

A. The tank truck or railcar gasoline cargo tank meets the test requirements in 40 CFR 63.425(e), or the railcar gasoline cargo tank meets applicable test requirements in 40 CFR 63.425(i);

B. For each gasoline cargo tank failing the test in 40 CFR 63.425(f) or (g) at the facility, the cargo tank either:

1. Before repair work is performed on the cargo tank, meets the test requirements in 40 CFR 63.425(g) or (h); or

2. After repair work is performed on the cargo tank before or during the tests in 40 CFR 63.425(g) or (h), subsequently passes the annual certification test described in 40 CFR 63.425(e).

4.1.3-2 <u>Applicable Federal Standards (40 CFR 60, Subpart XX)</u>

The affected unit is subject to 40 CFR 60, Subpart XX: Standards of Performance for Bulk Gasoline Terminals.

Note: Pursuant to 40 CFR 63.420(g), each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of 40 CFR 63, Subpart R that is also subject to applicable provisions of 40 CFR part 60, Subpart XX shall comply only with the provisions in each subpart that contain the most stringent control requirements for that facility.

4.1.3-3 <u>Applicable State Regulations (35 IAC Part 219, Subpart B)</u>

The affected unit is subject to 35 IAC 219.122(a), which provides that no person shall cause or allow the discharge of more than 3.6 kg/hour (8 lbs/hour) of organic material into the atmosphere during the loading of any organic material from the aggregate loading pipes of any loading area having throughput of greater than 151 cubic meters per day (40,000 gallons/day) into any railroad tank car, tank truck or trailer unless such loading area is equipped with submerged loading pipes or a device that is equally effective in controlling emissions and is approved by the Agency according to the provisions of 35 IAC 201, and further processed consistent with 35 IAC 219.108.

4.1.4 Non-Applicability of Regulations of Concern

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

4.1.5 Control Requirements and Work Practices

a. i. BACT Technology

The loading rack control device (e.g., VCU) shall be maintained and operated with good combustion practice to reduce emissions of CO.

ii. BACT Emission Limit

Emissions of CO from the control system for the affected unit shall not exceed 0.0835 lb/1,000 gallons of petroleum product loaded, during loading of material.

b. i. LAER Technology

A. The affected unit shall be controlled by the loading rack control device (e.g., VCU), consistent with the NESHAP (40 CFR 63, Subpart R), which system shall be maintained and operated with good combustion practice to reduce emissions of VOM.

B. The uncaptured emissions from the affected unit shall be minimized by compliance with the requirements of the NESHAP (40 CFR 63, Subpart R) addressing vapor tightness of cargo tanks and operation of vapor collection systems.

ii. LAER Emission Limit

Emissions of VOM from the loading rack control device (e.g., VCU) ,expressed as Total Organic Compounds (TOC) shall not exceed 7.0 mg/L of gasoline loaded.

Condition 4.1.5(a) represents the application of the Best Available Control Technology. Condition 4.1.5(b) represents the application of the Lowest Achievable Emission Rate.

4.1.6 Production and Emission Limitations

a. Operation of the affected unit shall not exceed the following limits:

Material	Throughput	
	(Gallons/Month)	(Gallons/Year)
Gasoline	51,100,000	306,600,000
Distillate	51,100,000	306,600,000

b. Emissions from the affected unit attributable to material combusted in the VCU shall not exceed the following limits:

Pollutant	Emission Limit		Increase[1]
	(Tons/Month)	(Tons/Year)	(Tons)
CO	4.3	25.6	23.8
NO_x	1.7	10.2	9.5
VOM (Captured)	---	12.8	12.5
VOM (Fugitive)	---	20.1	19.9

[1] The increase in emissions is based upon a comparison of the actual emissions (average of 2004 and 2005) with the emission limits.

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

4.1.7 Testing and Inspection Requirements

a. The Permittee shall comply with the applicable test methods and procedures in 40 CFR 63.425. In particular, the owner or operator subject to the emission standard in 40 CFR 63.422(b) shall comply with the requirements in 40 CFR 63.425(a)(1) and (2) [40 CFR 63.425(a)].

i. Conduct a performance test on the vapor processing and collection systems according to either 40 CFR 63.425(a)(1)(i) or (ii).

A. Use the test methods and procedures in 40 CFR 60.503, except a reading of 500 ppm shall be used to determine the level of leaks to be repaired under 40 CFR 60.503(b); or

B. Use alternative test methods and procedures in accordance with the alternative test method requirements in 40 CFR 63.7(f).

ii. The performance test requirements of 40 CFR 60.503(c) do not apply to flares defined in 40 CFR 63.421 and meeting the flare requirements in 40 CFR 63.11(b). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in 40 CFR 63.11(b) and 40 CFR 60.503(a), (b), and (d), respectively.

4.1.8 Monitoring Requirements

a. The owner or operator shall install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) as specified in 40 CFR 63.427(a)(1), (a)(2), (a)(3), or (a)(4), except as allowed in (a)(5) [40 CFR 63.427(a)].

   i. Where a carbon adsorption system is used, a continuous emission monitoring system (CEMS) capable of measuring organic compound concentration shall be installed in the exhaust air stream [40 CFR 63.427(a)(1)].

   ii. Where a refrigeration condenser system is used, a continuous parameter monitoring system (CPMS) capable of measuring temperature shall be installed immediately downstream from the outlet to the condenser section. Alternatively, a CEMS capable of measuring organic compound concentration may be installed in the exhaust air stream [40 CFR 63.427(a)(2)].

   iii. Where a thermal oxidation system other than a flare is used, a CPMS capable of measuring temperature must be installed in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs [40 CFR 63.427(a)(3)].

   iv. Where a flare meeting the requirements in 40 CFR 63.11(b) is used, a heat-sensing device, such as an ultraviolet beam sensor or a thermocouple, must be installed in proximity to the pilot light to indicate the presence of a flame [40 CFR 63.427(a)(4)].

   v. Monitoring an alternative operating parameter or a parameter of a vapor processing system other than those listed in 63.427(a) will be allowed upon demonstrating to the USEPA's satisfaction that the alternative parameter demonstrates continuous compliance with the emission standard in 40 CFR 63.422(b) [40 CFR 63.427(a)(5)].

4.1.9 Recordkeeping Requirements

a. The Permittee shall comply with the applicable recordkeeping requirements of 40 CFR 63.428.

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

   i. Identification of each type of material loaded.

ii. Amount of each material loaded (gallons/month and gallons/year).

iii. Emissions from the affected unit (tons/month and tons/year) with supporting calculations and documentation.

4.1.10 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 4.1). Reports shall include information specified in Conditions 4.1.10(a)(i) and (ii).

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

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

b. The Permittee shall comply with the applicable reporting requirements specified in 40 CFR 63.428.

4.2 Storage Tanks

4.2.1 Description

New tanks will be installed as part of this project as follows:

- Two new ethanol tanks (Tanks 209 and 210). These tanks will have an internal floating roof.
- Two new distillate tanks (Tanks 2001 and 2002). These tanks will be a fixed roof design.
- A new gasoline tank (Tank 2003). This tank will have an internal floating roof.

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

4.2.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Tank 209	New ethanol storage tank; 20,000 barrel capacity.	Internal Floating Roof
Tank 210	New ethanol storage tank; 20,000 barrel capacity	Internal Floating Roof
Tank 2001	New distillate storage tank; 200,000 barrel capacity; fixed roof.	None
Tank 2002	New distillate storage tank; 200,000 barrel capacity; fixed roof.	None
Tank 2003	New gasoline storage tank; 200,000 barrel capacity.	Internal Floating Roof

4.2.3 Applicable Provisions and Regulations

a. An "affected tank" for the purpose of these unit-specific conditions, is a storage tank described in Conditions 4.2.1 and 4.2.2.

4.2.3-1 Applicable Federal Standards (40 CFR 60, Subpart Kb)

The affected ethanol and gasoline tanks 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, which provides that the affected ethanol and gasoline tanks shall be equipped with a fixed roof in combination with an internal floating roof meeting the following specifications:

a. 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)].

b. 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:

   i. 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)].

c. 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)].

d. 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)].

e. 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)].

f. 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)].

g. 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)].

h. 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)].

i. 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)].

4.2.3-2 Applicable Federal Standards (40 CFR 63, Subpart R)

The affected gasoline tank is subject to 40 CFR 63, Subpart R: National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), which provides that the affected gasoline storage tank shall be installed according to the requirements in 40 CFR 60.112b(a)(1), except for the requirements in 40 CFR 60.112b(a)(1)(iv) through (ix) [40 CFR 63.423(a)].

4.2.3-3 Applicable State Regulations (Storage Containers of VOL)

The affected ethanol tanks are subject to 35 IAC 219.120: Control Requirements for Storage Containers of VOL, which provides that the affected ethanol tanks shall be equipped with an internal floating roof that meets the following specifications:

a. 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 and subsequently 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.

b. Each 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:

    i. 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.

c. 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.

d. 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.

e. 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.

f. 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.

g. 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.

h. Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

4.2.3-4 Applicable State Regulations (Storage Containers of VPL)

The affected gasoline tank is subject to 35 IAC 219.121: Storage Containers of VPL, which provides that:

a. The affected gasoline tank 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)].

4.2.3-5 Applicable State Regulations (Loading Operations)

The affected tanks are subject to 35 IAC 219.122: Loading Operations, which provides that:

a. 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)].

b. Pursuant to 35 IAC 219.122(c), if no odor nuisance exists the limitations of 35 IAC 219.122(b) shall only apply to the loading of volatile organic liquids with a vapor pressure of 17.24 kPa (2.5 psia) or greater at 294.3°K (70°F).

4.2.4 Non-Applicability of Regulations of Concern

a. The affected distillate tanks are not subject to 40 CFR 60 Subpart Kb, because the affected distillate tanks are storage vessels 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)].

b. This permit is issued based on the affected distillate and gasoline tanks not being subject to 35 IAC 219.120 pursuant to 219.119(e) because the affected tanks are only used to store petroleum liquids.

c. i. This permit is issued based on the affected distillate tanks not being subject to 35 IAC 219.121: Storage Containers of VPL, because the affected distillate tanks 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 ethanol tanks not being subject to 35 IAC 219.121: Storage Containers of VPL, because the affected ethanol tanks will not store a volatile petroleum liquid as defined in 35 IAC 211.4610.

d. i. This permit is issued based on the affected distillate tanks not being subject to 35 IAC 219.123: Petroleum Liquid Storage Tanks, because the affected distillate tanks 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 ethanol and gasoline tanks not being subject to 35 IAC 219.123: Petroleum Liquid Storage Tanks, because the affected tanks 209, 210, and 2003 are subject to 40 CFR 60 Subpart Kb [35 IAC 219.123(a)(5)].

4.2.5 Control Requirements and Work Practices

a. LAER Technology

i. Affected ethanol and gasoline tanks shall be controlled by an internal floating roof with a primary liquid-mounted seal consistent with the control requirements of the 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart R and a secondary rim-mounted seal.

ii. The true vapor pressure of the material stored in the affected distillate tanks shall not exceed 0.1 psia at the maximum storage temperature.

Condition 4.2.5(a) represents the application of the Lowest Achievable Emission rate.

4.2.6 Production and Emission Limitations

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

	Throughput		VOM Emissions
Tank	(MMGal/Mo)	(MMGal/Yr)	(Tons/Yr)
209 & 210	5.2	30.7	0.1

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

	VOM Emissions
Tank	(Tons/Year)
2001 & 2002	1.5
2003	13.1

Note: The working losses from affected tanks 2001, 2002, and 2003 are addressed by Condition 3.3.1, which includes both new and existing gasoline and distillate storage tanks.

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

4.2.7 Testing and Inspection Requirements

a. For the affected gasoline tank, the Permittee shall comply with the applicable test methods and procedures in 40 CFR 63.425.

b. The Permittee shall fulfill all applicable testing and procedures requirements of 40 CFR 60.113b(a) for the affected ethanol and gasoline tanks [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 ethanol and gasoline tanks [40 CFR 60.116b].

4.2.8 Monitoring Requirements

Monitoring requirements are not set for the affected tanks.

4.2.9 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 gasoline and ethanol tanks [40 CFR 60.115b].

c. The Permittee shall fulfill all applicable recordkeeping requirements of 40 CFR 63.428 for the affected gasoline tank, which records shall be kept for at least 5 years.

4.2.10 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 4.2). Reports shall include information specified in Conditions 4.2.10(a)(i) and (ii).

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

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

b. The Permittee shall fulfill all applicable reporting requirements specified in 40 CFR 60.115b for the affected gasoline and ethanol tanks [40 CFR 60.115b].

c. The Permittee shall fulfill all applicable reporting requirements of 40 CFR 63.428 for the affected gasoline tank.

4.3 Components

4.3.1 Description

New piping will be required to connect the new storage tanks and modified loading rack. 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)	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 terminal expansion as described in Conditions 4.3.1 and 4.3.2, and any subsequent replacement of such new component.

4.3.3-1 Applicable Federal Standards (40 CFR 63, Subpart R)

Certain affected components are subject to 40 CFR 63, Subpart R: National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), which provides that:

a. The Permittee shall perform a monthly leak inspection of all equipment in gasoline service. For this inspection, detection methods incorporating sight, sound, and smell are acceptable. Each piece of equipment shall be inspected during the loading of a gasoline cargo tank [40 CFR 63.424(a)].

b. A log book shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility [40 CFR 63.424(b)].

c. Each detection of a liquid or vapor leak shall be recorded in the log book. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in 40 CFR 63.424(d) [40 CFR 63.424(c)].

d. Delay of repair of leaking equipment will be allowed upon a demonstration to the USEPA that repair within 15 days is not feasible. The owner or operator shall provide the reason(s) a delay is needed and the date by which each repair is expected to be completed [40 CFR 63.424(d)].

e. Initial compliance shall be achieved upon startup [40 CFR 63.424(e)].

f. As an alternative to compliance with the provisions in 40 CFR 63.424(a) through (d), owners or operators may implement an instrument leak monitoring program that has been demonstrated to the USEPA as at least equivalent [40 CFR 63.424(f)].

g. Owners and operators shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following [40 CFR 63.424(g)]:

    i. Minimize gasoline spills;

    ii. Clean up spills as expeditiously as practicable;

    iii. Cover all open gasoline containers with a gasketed seal when not in use;

    iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

4.3.3-2 Applicable State Regulations (35 IAC 219, Subpart C)

Pursuant to 35 IAC 219.142, no person shall cause or allow the discharge of more than 32.8 ml (2 cu in) of volatile organic liquid with vapor pressure of 17.24 kPa (2.5 psia) or greater at 294.3°K (70°F) into the atmosphere from any pump or compressor in any 15 minute period at standard conditions.

4.3.4 Non-Applicability of Regulations of Concern

None.

4.3.5 Control Requirements and Work Practices

a. LAER Technology

    i. Affected components shall comply with the 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 open-ended valves or lines shall comply with the standards for open-ended valves or lines in 40 CFR 63.167.

C. 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.

D. 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 and existing components at the terminal shall not exceed 2.5 tons per year (combined). This limit represents an increase of 0.2 tons VOM. 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 use the Test Methods and Procedures of 40 CFR 60.485.

4.3.8 Monitoring Requirements

None.

4.3.9 Recordkeeping Requirements

a. The Permittee shall maintain records consistent with the recordkeeping requirements of 40 CFR 60.486.

b. 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 submit reports consistent with the Reporting requirements of 40 CFR 60.487.

4.4 Roadways

4.4.1 Description

The affected units for the purpose of these unit-specific conditions are roadways affected by the CORE project, 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.

4.4.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Roadways	Paved roads	Pavement of Roadways

4.4.3 Applicable Provisions and Regulations

a. An "affected unit" for the purpose of these unit-specific conditions, are the units described in Conditions 4.4.1 and 4.4.2.

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 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.

4.4.4 Non-Applicability of Regulations of Concern

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

4.4.5 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.

4.4.6 <u>Production and Emission Limitations</u>

a. The emissions of fugitive dust from roadways shall not exceed 10.7 tons/year of PM and 2.1 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).

4.4.7 <u>Testing Requirements</u>

a. Silt Loading Measurements

i. The Permittee shall conduct measurements of the silt loading on various affected roadway segments, 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.

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, and changes in the standard operating practices for affected units, such as application of salt or traction material during cold weather.

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 3.6.1, 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.

4.4.8 Monitoring Requirements

Monitoring requirements are not set for the affected units.

4.4.9 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, with supporting documentation for the determination of wind speed.

b. The Permittee shall keep records for the silt measurements conducted for affected units pursuant to Condition 4.4.7(a), including records for the sampling and analysis activities and results.

c. The Permittee shall maintain records for the PM emissions of the affected units to verify compliance with the limits in Condition 4.4.6, based on the above records for the affected units, and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.

d. 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 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 factors (lbs/vehicle mile traveled), based on methodology for estimating emissions published by USEPA, with supporting explanation and calculations.

   iii. Records of the estimated vehicle miles traveled on each roadway segment (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.

iv. Records for emissions, in tons/month, based on the emission factors and other information contained in other required records, with supporting calculations.

4.4.10 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	$PM_{10}/PM_{2.5}$ *
Wood River Products Terminal							
Loading Rack	9.5	9.5	23.8	---	32.4	---	---
Tanks	---	---	---	---	21.4	---	---
Components	---	---	---	---	0.2	---	---
Roadways	---	---	---	---	---	10.0	1.9
SUBTOTAL:	9.5	9.5	23.8	---	54.0	10.0	1.9
Refinery CORE Increases	986.7	948.6	1,039.1	1,548.3	329.0	319.2	224.8
SUBTOTAL:	996.2	958.1	1,062.9	1,548.3	383.0	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:	**- 47.5**	**- 85.6**	**1,047.4**	**-9,583.1**	**382.7**	**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 2nd Reheat Heater (fuel switch)	11/2002	339.0
CR-3 1st 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 - Summary of BACT/LAER Determinations

Operation	Permit Section	BACT Determination for CO Control Technology/Emission Limit	LAER Determination for VOM Control Technology/Emission Limit
Loading Rack	4.1	Good combustion practices/0.0835 lb/1000 gallons petroleum product loaded.	Good combustion practices; vapor tightness/7 mg/L of gasoline loaded.
New Storage Tanks	4.2	N/a.	Internal Floating Roof with primary and secondary seals for the new gasoline and ethanol tanks; true vapor pressure of material stored limited to 0.1 psia for the new distillate tanks.
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 for pumps in light liquid service.

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.

217/782-2113

CONSTRUCTION PERMIT - NESHAP SOURCE - NSPS SOURCE - PSD APPROVAL

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: July 19, 2007
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.
Acting Manager, Permit Section
Division of Air Pollution Control

Date Issued: ____________________

ECB:JMS:psj

cc: Region 3
Lotus Notes
CES

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 – (217) 782-3397
JAMES R. THOMPSON CENTER, 100 WEST RANDOLPH, SUITE 11-300, CHICAGO, IL 60601 – (312) 814-6026

ROD R. BLAGOJEVICH, GOVERNOR DOUGLAS P. SCOTT, DIRECTOR

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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
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
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SSMP	Startup, Shutdown, Malfunction Plan
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 coking 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, Missiouri/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.: "SO_2 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 Source-Wide Non-Applicability of Regulations of Concern

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 Source-Wide Production and Emission Limitations

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:

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

* 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 CR-3 H-5 CR-3 H-6	439.3 (combined limit)	13.7 (combined limit)	9.9 (combined limit)

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 averate).

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 (Tons/Mo)	(Tons/Yr)	VOM Emissions (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.

3.5 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 NO_x, VOM, and PM_{10} 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 PM_{10} from each cooling water tower (tons/month and tons/year).

c. Flares

i. A file showing the potential NO_x 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 H_2S 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 SO_2 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 H_2S in fuel gases before being burned in the affected heaters (or SO_2 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. NO_x, CO, VOM, SO_2, PM and PM_{10} 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)	(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 SO_2 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 H_2S in fuel gases before being burned in the affected unit (or SO_2 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 <u>Non-Applicability of Regulations of Concern</u>

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

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 Control Requirements and Work Practices

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 Production and Emission Limitations

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 <u>Reporting Requirements</u>

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 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
FCCU 1	Modified Fluidized Catalytic Cracking Unit (partial combustion unit)	SCR, WGS, CO Heater, Cyclones, Flare
FCCU 2	Modified Fluidized Catalytic Cracking Unit (partial combustion unit)	SCR, WGS, CO Heater, Cyclones, Flare
FCCU 3	Restart of Fluidized Catalytic Cracking Unit (full combustion unit)	SCR, WGS, Cyclones, Flare

4.5.3 Applicable Provisions and Regulations

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

b. NSPS 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 NO_x 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 SO_2 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 Recordkeeping Requirements

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, NO_x, SO_2, PM/PM_{10} 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 <u>Non-Applicability of Regulations of Concern</u>

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

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 <u>Production and Emission Limitations</u>

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:

	PM/PM_{10} Emissions		VOM Emissions	
Unit	(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 <u>Sampling and Analysis</u>

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 Recordkeeping Requirements

a. The Permittee shall keep records as set forth below for the affected units [35 IAC 219.986(d)(5)]:

   i. Records of inspection and monitoring activity;

   ii. Records of each leak identified in such tower, with date, time and nature of observation or measured level of parameter;

   iii. Records of activity to identify leaking components, with date initiated, summary of components inspected with dates, and method of inspection and observations; and

   iv. Records of activity to remove a leaking component from service or repair a leaking component, with date initiated and completed, description of actions taken and the basis for determining the leak in such tower has been eliminated. If the leaking component is not identified, repaired or eliminated within 30 days of initial identification of a leak in such tower, this report shall include specific reasons why the leak could not be eliminated sooner including all other intervening periods when the process unit was out of service, actions taken to minimize VOM losses prior to elimination of the leak and any actions taken to prevent the recurrence of a leak of this type.

b. The Permittee shall keep records of the total capacity of the affected units (gallons/minute, hourly average).

c. The Permittee shall keep records of emissions of VOM, PM, and 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

Flares dispose of releases of flammable process gas that can not be recovered, as can occur from various units, by combustion. These releases can occur from safety relief valves, test instruments and monitors, waste process gas and blowdown, and gases collected via vents and drains during depressurization of vessels or equipment in preparation for turnaround and maintenance. Many releases are of sufficient quantity that most of it may be compressed and recovered and then used in heaters and boilers after being processed with amine absorbers to remove H_2S. The excess that cannot be recovered is sent to a flare. The releases are generally hydrocarbons but may be hydrogen or any combination of hydrogen, hydrocarbon, sulfur compounds and inert gases. The flares burn the gases to form carbon dioxide, sulfur dioxide, and water. Only recovered gases are treated through the amine absorbers. If the compressor capacity is exceeded then these gases go directly to a flare and those gases are likely to contain H_2S.

Releases to flare systems are managed to prevent product loss. Some processes require a minor amount of venting during normal operation to safely dispose of non-condensable gases, such as nitrogen, that are present as dictated by the nature of the process.

The new coker flare is equipped with a system for using steam (i.e., steam-assisted) to assure more complete combustion.

As these flares combust process gases, they must be operated in compliance with applicable federal emissions standards for flaring.

4.7.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description
DCUF	New Coker Flare, Steam-Assisted
HP2F	New HP-2 Flare, Nonassisted

4.7.3 Applicable Provisions and Regulations

a. An "affected unit" for the purpose of these unit-specific conditions is a flare 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 J. The affected units are considered a fuel gas combustion device pursuant to this NSPS.

i. Pursuant to 40 CFR 60.104(a)(1), 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). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this requirement.

c. The affected units are subject to General Control Device Requirements specified at 40 CFR 60.18, which provides:

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. The Permittee 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. Owners or operators of flares used to comply with the provisions of 40 CFR 60.18 shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices [40 CFR 60.18(d)].

viii. Flares used to comply with provisions of 40 CFR 60.18 shall be operated at all times when emissions may be vented to them [40 CFR 60.18(e)].

Note: The affected units control VOM emissions from various emission units which are subject to certain regulations, which reference the general control device requirements in the NSPS at 40 CFR 60.18. In addition, both new and existing flares at the refinery become affected facilities under the NSPS pursuant to Paragraph 11 of the Consent Decree.

d. 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 affected flare to exceed 2,000 ppm.

4.7.4 Non-Applicability of Regulations of Concern

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

4.7.5 Control Requirements and Work Practices

a. BACT/LAER Technology

i. The affected units shall be operated with equipment design specifications and work practices consistent with the NSPS requirements for flares in 40 CFR 60.18.

ii. Gaseous fuels meeting the requirements of 40 CFR 60.104(a)(1) and process upset gases (as defined in 40 CFR 60.101(e)) shall be the only gases combusted in the affected units.

iii. The Delayed Coking Unit shall be designed, operated and maintained with a waste gas recovery system with redundant compressor capacity, i.e., a system with two or more waste gas recovery compressors whose capacity is sufficient to handle the normal range of waste gas generated from operation of the Delayed Coking 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 Delayed Coking Unit shall be conducted with waste 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 waste gases are sent to be combusted in an affected unit.

Note: Turnarounds of the delayed Coker Unit are subject to the requirements of 35 IAC 219.444.

v. Flaring associated with the Delayed Coker Unit and Hydrogen Plant shall be minimized by operating and maintaining the affected units, including the associated waste gas recovery system for the Delayed Coker Unit, in accordance with a Flaring Minimization Plan (Plan) in accordance with Condition 4.7.6-2, which Plan may be consolidated with other plans required for the Delayed Coker Unit and affected units, such as the turnaround plan required by 35 IAC 219.444(b).

vi. The Permittee shall conduct an event-specific investigation into each hydrocarbon flaring incident for the Delayed Coker Unit or Hydrogen Plant, which investigation shall include a root-cause analysis for the incident unless the Permittee relies upon a previous analysis for an incident, with a report for the incident and investigation submitted to the Illinois EPA in accordance with Condition 4.7.10(d). For this purpose, a hydrocarbon flaring incident is the flaring of waste gas that involves flaring of 100,000 scf or more of waste gas or results in VOM emissions of 50 or more pounds in a period of 24 hours or less.

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

b. The Permittee shall not vent any gas stream containing reduced sulfur compound concentrations to an affected unit that would cause the SO_2 into the atmosphere from any affected unit to exceed 2,000 ppm, except as allowed by

Condition 4.7.5(b)(i). This requirement ensures that the affected units meet the emission standard of 35 IAC 214.301.

i. Subject to the following terms and conditions, the Permittee is authorized pursuant to 35 IAC 201.149 to vent gases containing reduced sulfur compound concentrations to the DCUF (Coker Flare) that would cause the sulfur dioxide emissions into the atmosphere from this flare to exceed the limitations stated in 35 IAC 214.301 during malfunctions of equipment venting to DCUF:

   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 and 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.

4.7.6-1 Emission Limitations

a. 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:

Emission Unit	Emissions (Tons/Year)				
	CO	NO_x	SO_2	VOM	PM/PM_{10}
DCUF	24.3	4.5	644.5	4.1	---
HP2*	147.9	246.8	127.2	24.8	45.6

* Note: HP2 includes HP2 H-1, CWT 24, HP2F, and HP2 Fugitives.

4.7.6-2 Flaring Minimization Plan

a. The Flaring Minimization Plan (Plan) prepared by the Permittee for the Delayed Coker Unit and Hydrogen Plant shall include the following:

i. A general description of the Delayed Coker Unit, including the associated waste gas recovery system and affected units, accompanied by process flow diagram(s).

ii. A description of the Permittee's written operating procedures for the normal operation of the Delayed Coker Unit, including recovery of waste gas 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 Delayed Coker Unit.

iv. A detailed description of the Permittee's procedures for flaring due to occurrence of process upsets or equipment failures, 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 Delayed Coker Unit, including the planning conducted as part of such work to minimize flaring.

vi. A detailed description of the Permittee's procedures for the fuel gas systems to facilitate acceptance of waste gas and to maintain or restore recovery of waste gas during flaring events.

vii. A detailed description of the Permittee's procedures for preventative maintenance of the Delayed Coker

Unit, 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.

b. i. The Permittee shall submit a copy of the Plan to the Illinois EPA for review and comments at least 60 days prior to initial startup of the delayed Coker Unit.

ii. The Permittee shall review the Plan on at least an annual basis and revise the plan so that it is kept current.

iii. The Permittee shall make changes to the Plan upon request by the Illinois EPA for an emission unit if required by the Illinois EPA or USEPA, as provided for by 40 CFR 63.6(e)(3)(vii), or as otherwise required by 40 CFR 63.6(e)(viii) [40 CFR 63.6(e)(3)(vii) and (viii)].

iv. These Plans are records required by this permit, which the Permittee must retain 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.

4.7.7 <u>Testing Requirements</u>

a. i. Upon request by the Illinois EPA, the Permittee shall conduct testing of an affected unit under such operating conditions as may be specified by the Illinois EPA and/or USEPA. This test shall meet the following requirements:

A. The test shall be conducted by an approved independent testing service.

B. The test shall be conducted during conditions which are representative of maximum emissions during normal operation.

ii. The following methods shall be used for testing:

A. 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)].

B. 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).

C. The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (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)].

D. The maximum permitted velocity, V_{max}, for flares complying with 40 CFR 60.18(c)(4)(iii) shall be determined by the equation in 40 CFR 60.18(f)(5).

E. The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the equation in 40 CFR 60.18(f)(6).

b. i. Upon request by the Illinois EPA, the Permittee shall conduct sampling of process streams in the Delayed Coker Unit to obtain representative samples of the waste gases that would be sent to the flare for the Unit if waste gases were to be flared.

ii. The Permittee shall have these samples analyzed for hydrocarbon and sulfur content 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. i. As provided by the NSPS, compliance with the H_2S standard in 40 CFR 60.104(a)(1) shall be measured as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration in the fuel gas. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line [40 CFR 60.106(e)(1)].

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

A. An instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere from the affected units. The monitor shall include an oxygen monitor for correcting the data for excess air; or

B. An instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases subject to 40 CFR 60.104(a)(1) before being burned in the affected units.

Note: The combustion 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 H_2S limitation in 40 CFR 60.104(a)(1). Continuous monitoring is not required for exempt gas streams.

iii. 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. 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. [40 CFR 60.18(f)(2)]

c. The Permittee shall continuously monitor each affected unit associated with the Delayed Coking Unit for the occurrence of flow of waste gases, other than normal flow of purge gas and leakage from "closed" pressure relief valves, to the affected unit.

d. The Permittee shall continuously monitor either: 1) The flow and hydrocarbon and sulfur content of waste gas to each affected unit associated with the Delayed Coking Unit; or 2) The operating parameters of the Delayed Coking Unit and affected units as needed for the flow and composition of waste gas to the affected units to be determined.

e. The Permittee shall keep records of the data collected by these monitoring systems and the operation and maintenance of these monitoring systems, including:

   i. Records of the date and duration of any time when a required monitoring instrument or device for an affected unit was not in operation, with explanation.

   ii. Records to address compliance with Condition 4.7.3(b)(i) of 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).

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

4.7.8-2 Observation Requirements

a. Unless a *continuous* video image of the flare tip of an affected unit is provided to the operator(s) in the control room for an affected unit, the Permittee shall conduct observation for visible emissions from an affected unit when waste gases are flared for more than 30 minutes, as follows:

   i. Observations shall not be required between sunset and sunrise, during other 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 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 45 minutes after the start of the flare event and continue on at least an hourly basis 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 <u>Recordkeeping Requirements</u>

The Permittee shall maintain records of the following items:

a. A file containing an engineering analysis for the waste gas recovery system for the Delayed Coker Unit addressing compliance with Condition 4.7.5(a)(iii), including a description of the recovery system, the capacity of each compressor, and information on the generation of waste gas during the different modes of operation of the Delayed Coker Unit.

b. A file that contains documentation for the methodology that the Permittee will follow for calculating emissions from each affected unit, including:

i. A description of the procedure for calculating emissions attributable to combustion of fuel for the pilot flame fuel, purge gas and waste gas.

ii. A description of the procedures for determining flows of different streams to the flare as related to operational monitoring, if continuous monitoring is not conducted for a stream.

iii. A description of the procedures for determining the composition of different streams to the flare as related to operational monitoring, if continuous monitoring is not conducted for a stream, with the composition that will be used for different streams, with supporting documentation.

c. Records of the following items for each exceedance of a standard, requirement of limit in Condition 4.7.3, 4.7.5, 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.

d. Records for operation and emissions of each affected unit, including:

i. Operation and emissions associated with the pilot flame and purge gas streams.

ii. Information for each period when waste gas was flared, including, date, time, duration, reason for flaring, total volume of gas flared*, whether any waste gas was recovered for fuel with estimated amount, hydrocarbon and sulfur content of the waste gas*, total emissions of 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.

e. Records of VOM, NO_x, SO_2, and CO emissions from each affected unit (tons/month and tons/year).

f. Records, pursuant to 35 IAC 201.263, of continued operation of equipment venting to the DCUF subject to Condition 4.7.5(b)(i) during malfunctions and 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 affected equipment venting to the DCUF continued to operate in accordance with Condition 4.7.5(b)(i).

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 reporting requirements specified in 40 CFR 60.107(e) and (f) and 40 CFR 60.105(e)(3).

b. The Permittee shall promptly notify the Illinois EPA of deviations of an affected unit with the permit requirements of this section (Section 4.7), as follows. Reports shall include information specified in Condition 4.7.10(b)(i).

i. Exceedance of the limits in Conditions 4.7.3, 4.7.5, or 4.7.6, shall be reported within 30 days and shall 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 standard.

D. A description of the cause of the possible exceedance.

E. When compliance was reestablished.

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 DCUF subject to Condition 4.7.5(b)(i) during malfunction or breakdown:

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 three days, 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 the DCUF 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 the DCUF was taken out of service.

C. If compliance is not achieved within 5 working days of the occurrence, the Permittee shall submit interim status reports to the Illinois EPA, Air Compliance Unit and Regional Field Office, within 5 days of the occurrence and every 14 days thereafter, 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 the DCUF will be taken out of service.

ii. The Permittee shall submit semi-annual malfunction and breakdown reports to the Illinois EPA consistent with the source's CAAPP permit. These reports may be submitted along with other semi-annual reports required by the source's CAAPP permit and shall include the following information for malfunctions and breakdowns of equipment venting to the DCUF 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 affected operation(s) involved in the incident.

B. Dates of the notices and reports of Conditions 4.7.10(c)(i).

C. Any supplemental information the Permittee wishes to provide to the notices and reports of Conditions 4.7.10(c)(i).

D. The aggregate duration of all incidents during the reporting period.

E. If there have been no such incidents during the reporting period, this shall be stated in the report.

d. 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. List each event during the year when waste gas was flared, with a description of the event, including cause, amount of emissions and duration.

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.

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

iv. Provide an analysis of the amount of waste gas that was recovered as related to the amount of waste gas that was flared.

v. Summarize actions or measures implemented during the previous year taken to reduce flaring, and the reason for and observed effect of these actions.

vi. Summarize actions or measures planned for implementation during the current year to reduce flaring, and the reason for and expected effect of these actions.

d. With the periodic monitoring reports required by the CAAPP permit for the source, for any reporting period in which significant flaring incident(s) occurred, the Permittee shall submit report(s) to the Illinois EPA for the root cause analysis performed for the incident(s) pursuant to Condition 4.7.5(a)(vi).

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 Non-Applicability of Regulations of Concern

None.

4.8.5 Control Requirements and Work Practices

a. i. BACT/LAER Technology

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

ii. BACT Emission Limit

Emissions of CO from 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:

	NO_x	CO	VOM	SO_2	PM/PM_{10}
Equipment	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)
SRU-E	18.4	21.6	1.4	218.7	2.0
SRU-F	18.4	21.6	1.4	218.7	2.0

b. Compliance with annual limits shall be determined 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 SO_2 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 coking 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 <u>Monitoring Requirements</u>

Monitoring requirements are not set for the affected units.

4.11.9 <u>Recordkeeping Requirements</u>

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	18.5	18.5	111.7	650.3	17.0	---	---
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:	986.7	948.6	1,039.1	1,548.3	329.0	319.2	224.8
Terminal CORE Increases	9.5	9.5	23.8	---	54.0	10.0	1.9
SUBTOTAL:	996.2	958.1	1,062.9	1,548.3	383.0	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:	- 47.5	- 85.6	1,047.4	-9,583.1	382.7	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 2nd Reheat Heater (fuel switch)	11/2002	339.0
CR-3 1st 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 - 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.
Flares	4.7	Good operating practices; 40 CFR 60.18; minimized flaring, including Flaring Minimization Plan.	Good operating practices; 40 CFR 60.18; minimized flaring, including Flaring Minimization Plan.
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 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.