Illinois Environmental Protection Agency
Bureau of Air, Permit Section

Project Summary for Applications from Phillips 66 Company and Phillips 66 Carrier LLC for Revisions to the Construction Permits for the Coker and Refinery Expansion (CORE) Project at the Wood River Refinery in Roxana, Illinois and the Terminal Expansion Project at the Hartford Terminal in Hartford, Illinois

Wood River Refinery	Hartford Terminal
Site Identification No.: 119090AAA	Site Identification No.: 119050AAN
Permit No.: 06050052	Permit No.: 06110049
Date Received: August 29, 2013	Date Received: September 6, 2013

Illinois EPA Contacts:

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Schedule:

Public Comment Period Begins:	September 29, 2014
Public Hearing:	November 13, 2014
Public Comment Period Closes:	December 13, 2014

I. INTRODUCTION

Phillips 66 Company (Phillips) and Phillips 66 Carrier LLC (Phillips 66 Carrier) have submitted applications for revisions to the construction permits issued to the Wood River Refinery (WRR) and Hartford Terminal (Terminal) for the Coker and Refinery Expansion (CORE) Project and the Terminal Expansion Project, respectively. The requested revisions address planned changes due to differences in the composition of the crude oil available to the WRR.

The Illinois Environmental Protection Agency (Illinois EPA) has reviewed the applications and made a preliminary determination that both applications meet applicable requirements. In particular, the projects will be developed to use best available control technology (BACT) and lowest achievable emission rate (LAER), as applicable, to reduce emissions. The air quality analyses conducted for the projects show that they will not cause violations of applicable ambient air quality standards.

The Illinois EPA has prepared drafts of the revised air pollution control construction permits that it would propose to issue. Prior to issuing these revised permits, the Illinois EPA is holding a public comment period that includes a public hearing to receive comments on the revised terms and conditions of the draft permits.

II. BACKGROUND

The WRR is a petroleum refinery located in Hartford and Roxana, Illinois. It processes crude oil into a variety of products including gasoline, diesel fuel, heating oil, asphalt, solvents and petroleum coke. These products are made by separating the crude oil into different fractions based upon their boiling points. Certain fractions may be directly usable as products with only minor further processing to convert them into streams with desired properties. Other fractions require additional processing. The WRR has requested changes to enable it to continue to meet the demand for gasoline and diesel fuel in the Midwest. Refer to Attachment 1 for a glossary of pertinent refining and regulatory terms.

WRB Refining LP (WRB) owns the WRR. Phillips operates the WRR, previously operated by ConocoPhillips Company (ConocoPhillips). ConocoPhillips[1] obtained a construction permit from the Illinois EPA for the CORE Project (Construction Permit No. 06050052) to install facilities to increase both the total crude oil processing capacity of the WRR and the percentage of heavier material able to be processed at the WRR. Construction under this permit commenced on September 8, 2008 and continues at this time.[2]

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[1] Permit No. 06050052 was transferred to Phillips on May 1, 2012.

[2] Following public comment and an appeal, the final CORE Permit was issued August 5, 2008. WRR has notified Illinois EPA that construction on the project began on September 8, 2008 and continues through the present. The first newly permitted unit to come online was the Benzene Extraction Unit Heater No. 3 (BEU H-3) in 2009. The new coker (Delayed Coker Unit No. 2) began operating in November 2011. Construction of Ultra Low Sulfur Diesel Unit No. 2 (ULD-2) is ongoing with an expected completion date in 2016.

The Terminal, located in Hartford, Illinois, is a petroleum terminal that receives and distributes various petroleum products. It receives refined petroleum products from the WRR, stores material in bulk storage tanks, and then redistributes through two modes of transportation: trucks and pipeline systems. The Terminal also receives and stores petroleum blend stocks by pipeline.

Phillips 66 Carrier owns and Phillips 66 Pipeline LLC operates the Terminal, which was previously operated by ConocoPhillips Pipeline Company (CPPL). CPPL[3] obtained a construction permit from the Illinois EPA for the Terminal Expansion Project (Construction Permit No. 06110049) to make certain modifications to the existing Terminal to accommodate the WRR's CORE Project.

Illinois EPA considered the initial CORE Project at the WRR and the initial Terminal Expansion Project at the Terminal to comprise a single larger project for purposes of the New Source Review programs that applied to permitting of the proposed projects. Illinois EPA is considering the revisions to both construction permits (Nos. 06050052 and 06110049) in the same manner.

III. OVERVIEW OF REQUEST

The original objective of the CORE Project was to increase the processing of a heavier crude material at WRR. The original design of the project assumed that the heavy crude would contain a larger fraction of petroleum, termed "heavy gas oil."[4] For this reason, the original CORE Project included elements to process this material, including reactivation of an existing, but idled fluid catalytic cracking unit (FCCU-3). Since the issuance of the CORE Permit, the mix of crude oil that is available contains less "heavy gas oil" and more "lighter oils." Consequently, FCCU-3 will not be needed; however, WRR will require other facilities to process this lighter material. This will include additional fractionation equipment (two new fractionating columns), and a new boiler to provide steam that would have otherwise been provided by FCCU-3. Also, increased utilization of other existing associated emission units will be necessary to process the lighter fraction of the crude oil. Phillips has requested revisions to the CORE Permit to reflect these changes to the CORE Project due to the change in crude oil composition. This proposed revision is referred to as the CORE Permit Revision.

Phillips also has requested other minor corrections, clarifications, and updates to the original CORE Permit, as summarized in Attachment 2. As a general matter, the CORE Permit Revision will result in lower overall permitted emissions, as compared to the original CORE Permit.

Certain changes are also proposed at the associated Terminal, i.e., in the Terminal Permit Revision. Three storage tanks that were originally planned will not be built. However, another tank needed to accommodate

[3] Permit No. 06110049 was transferred to Phillips 66 Carrier on June 1, 2013.
[4] The heavy gas oil fraction of crude oil must generally undergo extensive processing to be converted into materials that can be used in products. This processing includes "cracking," splitting the bigger molecules into smaller molecules of suitable size. At the WRR, cracking is performed in Fluidized Catalytic Cracking Units (FCCUs) and heavy gas oil is one of the main feeds to the FCCU.

the changes to the CORE Project is planned. An application to revise Construction Permit No. 06110049 has been submitted for this change. Consistent with the initial permitting approach, the Illinois EPA is considering the Terminal Permit Revision for the proposed changes to the Terminal, together with the CORE Permit Revision to comprise a single permitting effort.

IV. FURTHER DISCUSSION OF EQUIPMENT CHANGES

A. Wood River Refinery

Phillips will continue to distill crude oil in crude distillation units at the WRR. The streams exiting these crude distillation units will continue to be routed within the WRR for further processing. The CORE Permit Revision will allow for some additional further fractionating at the new fractionation columns to process the lighter oil component. Some of the permitted additional cracking capability, i.e., FCCU-3, will not be constructed and will be removed from the CORE Permit. Removal of the additional cracking capability lowers emissions. Even with the addition of two new fractionating columns and a new boiler, the overall emissions with the proposed changes will be lower than emissions permitted in the original CORE Permit.

The CORE Permit Revision includes the following equipment changes:

The following units will not be constructed or reactivated, and will no longer be authorized:

- Fluidized Catalytic Cracking Unit 3 (FCCU-3);
- FCCU-3 Catalyst Loading;
- Cooling Water Tower 3 (CWT-3) (would have supported FCCU-3);
- Distilling West Cracked Gas Plant; and
- Two Crude Oil Storage Tanks (TK-A098 and TK-A099).

The following units will be constructed and will be authorized:

- Two fractionation columns (V-3245 and V-3247);
- A cooling water tower (CWT-26) (to support fractionators);
- Two product storage tanks (TK A-033-1 and TK A-037-1); and
- A boiler (Boiler 19).

Modifications will also be made to the existing straight run deisobutanizer column to increase fractionation capacity. Connections from the two new fractionation columns, and their associated equipment, will be made to the existing Distilling Flare for safety and emergency purposes. The Distilling Flare is equipped with a flare gas recovery system.

B. Hartford Terminal

Phillips 66 Carrier is requesting a revision to the Terminal Expansion Project Permit associated with the WRR CORE Project. The Terminal Permit Revision includes construction of a new storage tank (Tank 2003) with an internal floating roof, along with associated piping to store the petroleum product from the WRR.

Also, the following three storage tanks and modifications to the loading rack will not be constructed, and will no longer be authorized in the Terminal Expansion Permit:

- Modifications to Loading Rack;
- Tank 209 – 20,000 barrel ethanol;
- Tank 210 – 20,000 barrel ethanol; and
- Tank 2002 – 200,000 barrel distillate.

Like the WRR CORE Permit Revision, the changes included in the Terminal Permit Revision stem from crude oil containing less heavy gas oil and result in lower permitted emissions compared to the original Terminal Expansion Project.

V. APPLICABLE EMISSION STANDARDS

The applications show that the new and modified units that will be constructed/modified due to the CORE Permit Revision and the Terminal Permit Revision will comply with applicable state and federal emission standards, including the emission standards of the State of Illinois (35 Il. Adm. Code: Subtitle B) and applicable federal emission standards adopted by the United States Environmental Protection Agency (USEPA) (40 CFR Parts 60, 61, and 63).

A summary of regulations applicable to emissions units that would be newly constructed or modified by the proposed revisions to the CORE and Terminal Expansion Permits is provided in Attachment 3.

VI. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

A. Introduction

The CORE Project was originally subject to permitting under the federal rules for Prevention of Significant Deterioration (PSD), 40 CFR 52.21, as a major project for emissions of carbon monoxide (CO).[5] Because the WRR was already a major source of emissions for purposes of PSD, the criterion for whether the CORE Project was considered major was whether the increase or net increase in emissions from the single project for one or more pollutants regulated by PSD would qualify as significant, as defined by the PSD rules. The CORE Project[6] met this criterion for CO with an increase in CO emissions that exceeded the 100 tons per year significance level.[7] In addition, GHG emissions are now subject to regulation (for those emission units added or now modified as part of this CORE Permit Revision)[8] because significant increases in GHG

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[5] The Illinois EPA administers PSD permitting for sources in Illinois under an agreement with USEPA.
[6] There are no CO emissions associated with the Terminal Expansion Project.
[7] The CORE Project was not a major project for other pollutants regulated under the PSD program. This is because the increases were not significant or, in the case of volatile organic material, the WRR is located in an area that is designated nonattainment for ozone.
[8] There are no GHG emissions associated with the Terminal Expansion Project.

emissions must be addressed as part of PSD permitting if PSD permitting is required for other pollutants.[9,10]

Original CORE Permit – Annual Emissions (Tons/Year)

	Pollutant	Refinery CORE Increases	Terminal Expansion Increases	Refinery CORE Decreases (shown as negative values)	Creditable Contemporaneous Emission Increases	Creditable Contemporaneous Emission Decreases (shown as negative values)	Net Emissions Increase (or Decrease)
NANSR	**VOM**[a]	325.7	54.0				
	NO_X	945.2	9.5	-1,043.7	897.1	-822.9	-11.4
	$PM_{2.5}$[b]	224.8	1.9	-131.3	58.6	-398.6	-244.6
PSD	**CO**[a]	1,002.5	23.8				
	NO_X	983.3	9.5	-1,043.7	804.8	-732.6	24.7
	SO_2	1,087.2	---	-11,131.4	179.4	-1,733.6	-11,598.4
	PM	319.2	10.0	-131.3	58.6	-396.0	-139.5
	PM_{10}	224.8	1.9	-131.3	58.6	-381.2	-227.2

Table Notes:
--- Minimal or no increase.
[a] Netting was not performed for VOM and CO emissions as the project triggered NA NSR and PSD for those pollutants, respectively.
[b] Emissions of $PM_{2.5}$ were expressed as emissions of PM_{10} as a surrogate pollutant in the original permit.

[9] On June 23, 2014, the United States Supreme Court issued its opinion in *Utility Air Regulatory Group v. EPA*, holding that the EPA's interpretation that GHGs are "regulated pollutants" that can, on their own, trigger PSD and Title V permitting requirements was impermissible because it would cover small sources that Congress did not expect would need to undergo permitting. In addition, the EPA cannot deviate from the explicit 100 and 250 tons per year (tpy) applicability thresholds established under the CAA for the PSD and Title V programs. The court also held that the EPA has the discretion to require BACT for "anyway" sources, meaning sources which are otherwise subject to PSD permitting requirements based on emissions of non-GHG pollutants. While the Court also determined that EPA may establish de minimis thresholds, above which BACT would be required if PSD review was already triggered for other pollutants, it is assumed for this permit that the levels here would be above the de minimis level. *Utility Air Regulatory Group v. EPA, 189 L. Ed. 2d 372, 2014 U.S. LEXIS 4377 (U.S. Sup. Ct. June 23, 2014).*
[10] The proposed CORE Permit Revision results in lower emissions of GHGs than from the original CORE Permit. The GHG emissions from FCCU-3, alone, would have been more than the GHG emission increases from the new boiler and other emission units.

CORE Permit Revision – Annual Emissions (Tons/Year)

	Pollutant	Refinery CORE Increases	Terminal Expansion Increases	Refinery CORE Decreases (shown as negative values)	Creditable Contemporaneous Emission Increases	Creditable Contemporaneous Emission Decreases (shown as negative values)	Net Emissions Increase (or Decrease)
NANSR	VOM[a]	300.1	29.1				
NANSR	NO_x	921.8	---	-1,045.9	981.1	-822.9	34.2
NANSR	$PM_{2.5}$	161.7	---	-132.4	75.0	-370.3	-266.0
NANSR	SO_2	2,094.2	---	-11,131.3	259.3	-1,727.5	-10,505.3
	CO[a]	883.7	---				
PSD	NO_x	921.8	---	-1,045.9	888.8	-732.6	32.1
PSD	SO_2	2,094.2	---	-11,131.3	259.3	-1,727.5	-10,505.3
PSD	PM	282.6	---	-132.4	75.6	-378.8	-153.0
PSD	PM_{10}	176.1	---	-132.4	75.0	-364.0	-245.3
PSD	GHGs (CO_2e)[b]	216,300	50				
PSD	H_2S[c]	5.8	---				
PSD	TRS[c]	0.5	---				

Table Notes:
--- Minimal or no increase.
[a] Netting is not performed for VOM and CO emissions as the project triggers NA NSR and PSD for those pollutants, respectively.
[b] GHGs were not subject to regulation at the time the original CORE Permit application was submitted. Emissions are included for new and modified units addressed by this revision.
[c] Project emissions increases for H_2S and TRS are less than significant, therefore, netting is not required. TRS and H_2S emissions were not quantified in the original application but have been included in the revised application.

With the CORE Permit Revision, net emissions of NO_x, PM, PM_{10}, $PM_{2.5}$, H_2S, TRS, and SO_2 from the overall project either decrease or increase below the applicable significant emission rates.

Addressing the requested changes as revisions to the CORE Permit and the Terminal Expansion Permit is appropriate given the requested changes are substantially related to the original permit activities and occur on a timeline that ties them to the overall CORE Project. The requested changes are related to the activities authorized in the original construction permit and construction of those activities is ongoing, including the final phases of construction of the ULD-2 unit. The further revisions to the project are necessary to fulfill the original objectives of that project, to make changes to the refinery to increase the processing of heavier crude utilized at the refinery.[11] Accordingly, the adjustments to the applications are linked both technically and economically, i.e., to increase the processing of heavy crude at WRR.

Addressing other minor corrections, clarifications, and updates (as described in Attachment 2) as revisions is appropriate because these changes correct errors in the original permitting for the CORE Project.

Additionally, as presented in Attachment 6, Evaluation of Change in Emissions, the proposed CORE Permit Revision does not constitute either a fundamental change or result in a significant net increase in emissions from the change. Rather the proposed revision results in a smaller net increase in emissions relative to the original project and consequently, is appropriately classified as a minor permit revision under USEPA's permit modification guidance.[12]

The substantive requirement of the PSD rules for a major modification for a pollutant are: 1) A case-by-case determination of BACT, 2) An ambient air quality impact analysis to confirm that the project would not cause or contribute to a violation of the National Ambient Air Quality Standard(s) (NAAQS) or applicable PSD increment(s); and 3) An assessment of the impacts on soils, vegetation and visibility.

B. Best Available Control Technology (BACT)

Under the PSD rules, a source or project that is subject to PSD must use BACT to control emissions of pollutants subject to PSD. Phillips has provided a BACT demonstration in its application addressing emissions of pollutants that are subject to PSD for those new and modified emission units to be added for the CORE Permit Revision. The proposed CORE Permit Revision triggers the PSD permitting requirements due to the potential CO and GHG emissions increases.

BACT is defined by Section 169(3) of the federal CAA as:

> An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

The USEPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency

[11] Original CORE Permit issued by the Illinois EPA, Permit No. 06050052.
[12] "PSD Permit Modifications: Policy Statement on Changes to a Source, a Permit Application, or an Issued Permit and on Extensions to Construction Schedules," June 1985. Available at www.epa.gov/region7/air/nsr/nsrmemos/permmod.pdf ("Tyler Memo"); See also, "Guidance Document for Prevention of Significant Deterioration Permit Modifications," June 11, 1991; See also, WRB Refining LP Wood River Refinery, Request to Revise CORE Project Construction Permit, Appendix A, dated August 2013.

believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner.[13] First, the BACT analysis must include consideration of the most stringent control option that is available and technically feasible, (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts."

In this process, the most effective control operation that is available and technically feasible is assumed to constitute BACT for a particular unit, unless the energy, environmental and economic impacts associated with that control option are found to be excessive. An important resource for BACT determinations is USEPA's RACT/BACT/LAER Clearinghouse (Clearinghouse or RBLC), a national compendium of control technology determinations maintained by USEPA. Other documents that are consulted include general information in the technical literature and information on other similar or related projects that are proposed or have been recently permitted. If the source is subject to a NSPS, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to the NSPS emission rate. In other words, the applicable NSPS represents the maximum allowable emission limit from an emission unit. Furthermore, the BACT requirements only apply to the pollutants that are subject to PSD review (i.e., significant net emissions increase) and the emission units that are newly installed or physically modified, or have incurred a change in the method of operation. Therefore, the BACT analysis is only required for new or modified CO and GHG emission units included in this CORE Permit Revision.

A demonstration of BACT was provided in the permit application for emissions for the pollutants that are subject to PSD from the various emission units that would be added in the proposed CORE Permit Revision. The Illinois EPA's proposed determinations of BACT are discussed in Attachment 4. The draft permit includes proposed BACT requirements and limits for emissions of the pollutants that are subject to PSD. These proposed limits have generally been determined based on the following:

- Emission data provided by the applicant;
- The demonstrated ability of similar equipment to meet the proposed emission limits or control requirements;
- Compliance periods associated with limits that are consistent with guidance issued by USEPA;
- Emission limits that account for normal operational variability based on the equipment and control equipment design, when properly operated and maintained; and
- Review of emission limits and control efficiencies required of other similar facilities and emission units as reported in the Clearinghouse.

VII. AIR QUALITY IMPACT ANALYSIS

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[13] USEPA, Office of Air and Radiation, Memorandum from J.C. Potter to the Regional Administrators. Washington, D.C., December 1, 1987.

A. Introduction

The previous discussions addressed emissions and emission standards. Emissions are the quantity of pollutants emitted by a source, as they are released to the atmosphere from various emission units. Standards are set limiting the amount of these emissions as a means to address the presence of contaminants in the air. The quality of air that people breathe is known as the ambient air quality. Ambient air quality considers the emissions from a particular source after they have dispersed from the source following release from a stack or other emission point, in combination with pollutants emitted from other nearby sources and background pollutant levels. The level of pollutants in ambient air is typically expressed in terms of the concentration of the pollutant in the air. One form of this expression is parts per million. A more common scientific form for measuring air quality is “micrograms per cubic meter”, which are millionths of a gram by weight of a pollutant contained in a cubic meter of air.

The USEPA has standards for the level of various pollutants in the ambient air. These ambient air quality standards are based on a broad collection of scientific data to define levels of ambient air quality where adverse human health impacts and welfare impacts may occur. As part of the process of adopting air quality standards, the USEPA compiles scientific information on the potential impacts of the pollutant into a “criteria” document. Hence the pollutants for which air quality standards exist are known as criteria pollutants. Based upon the nature and effects of a pollutant, appropriate numerical standards and associated averaging times are set to protect against adverse impacts. For some pollutants several standards are set and for others only a single standard has been established.

Areas can be designated as attainment or nonattainment for criteria pollutants, based on the existing air quality. In an attainment area, the goal is to generally preserve the existing clean air resource and prevent increases in emissions which would result in nonattainment. In a nonattainment area efforts must be taken to reduce emissions to come into attainment. An area can be attainment for one pollutant and nonattainment for another. The WRR is located in Madison County which is classified as non-attainment for 8-hr ozone and $PM_{2.5}$ and attainment for all other criteria pollutants.

Compliance with air quality standards is determined by two techniques, monitoring and modeling. In monitoring, samples are actually taken of the levels of pollutants in the air on a routine basis. This is particularly valuable as monitoring provides data on actual air quality, considering actual weather and source operation. The Illinois EPA operates a network of ambient air monitoring stations across the state.

Monitoring is limited because monitors cannot be operated at all locations. Nor can monitoring be employed to predict the effect of a future source, which has not yet been built or to evaluate the effect of possible regulatory programs to reduce emissions. Modeling is used for these purposes. Modeling uses mathematical equations to predict ambient concentrations based on various factors, including the height of a stack, the velocity and temperature of exhaust gases and weather data (speed, direction and atmospheric missing). Modeling is performed by computer, allowing detailed estimates to be made of air quality impacts over a range of weather data. Modeling techniques are well developed for essentially stable pollutants like particulate matter, NO_X and CO and can readily address the impact of individual sources. Modeling techniques for reactive pollutants, e.g., ozone, are more complex and have generally been developed for analysis of entire urban areas. As such, these modeling techniques are not applied to a single source with small amounts of emissions.

Air quality analysis is the process of predicting ambient concentrations in an area as a result of a project and comparing the concentration to the air quality standard or other reference level. Air quality analysis uses a combination of monitoring data and modeling as appropriate.

B. Air Quality Analysis for CO

An ambient air quality analysis was completed to assess the impact of CO emissions from the proposed CORE Permit Revision on ambient air quality. The Terminal Expansion Project contains no associated CO emissions. The modeling analysis evaluated various boiler loadings, including startup, to determine worst-case CO emissions.

Because NO_x, PM_{10}, $PM_{2.5}$, H_2S, TRS, and SO_2 emissions from the CORE Permit Revision combined with the Terminal Permit Revision show either an emissions decrease or an increase below the applicable PSD threshold, no additional air quality analysis is required for these pollutants. Air quality analyses were not conducted for GHG because a NAAQS standard has not been established for GHG.

Modeling Procedure

Significance Analysis (Step 1): The starting point for determining the extent of the modeling necessary for any proposed project is evaluating whether the project would have a "significant impact". The PSD rules identify Significant Impact Levels (SIL) which represents thresholds triggering a need for more detailed modeling.[14] These thresholds are specified for all criteria pollutants except ozone and lead.

Refined (Full Impact) Analysis (Step 2): For pollutants for which impacts are above the SIL, more detailed modeling is performed by incorporating proposed new emissions units at the facility, stationary sources in the surrounding area (from a regional inventory), and a background concentration.

Refined Culpability Analysis (Step 3): For pollutants for which the refined modeling continues to indicate modeled exceedance(s) of a NAAQS, a more refined culpability (cause and contribute) analysis is performed incorporating additional specific procedures consistent with USEPA guidance.

The CORE Permit Revision and the Terminal Permit Revision will only impact emissions from emission points added or modified by the proposed

[14] The significant impact levels do not correlate with health or welfare thresholds for humans, nor do they correspond to any threshold for effects on flora or fauna. Significant impact levels are more conservative and protective than these thresholds.

revisions. Therefore, the original CORE Permit air quality model was used as a baseline with incremental adjustments in CO emission rates for new or modified emission points only. The maximum modeled ground-level concentrations of CO were then compared to the corresponding Significant Impact Level (SIL).

Modeling Results

The results of ambient air quality modeling of CO emissions from the CORE Project, with the proposed revisions, are presented in the following table.

Maximum Modeled Impacts Analysis (µg/m^3)

	1-Hour CO	**8-Hour CO**
Significant Impact Level	2,000	500
NAAQS Standard	40,000	10,000
2009 Meteorological Data	921	184
2010 Meteorological Data	1,084	251
2011 Meteorological Data	975	217
2012 Meteorological Data	1,057	237
2013 Meteorological Data	1,028	251

The Significance Analysis determined that modeled concentrations from the CORE Permit Revision did not exceed the SIL; therefore, no further analysis is necessary for CO. Since the maximum air quality impacts for CO predicted from the CORE Permit Revision are below the PSD SIL, air quality will not be measurably affected.

C. Vegetation and Soils Analysis

Pursuant to 40 CFR 52.21(o), an applicant for a PSD permit is required to conduct an analysis of the impairment to soils and vegetation that may occur as a result of the proposed source.

The applicant’s analysis of the potential impact of the proposed CORE Permit Revision and the Terminal Permit Revision, on soils, and vegetation relies on the detailed analysis completed for the original CORE Permit application.[15] Because permitted CO and VOM emissions will decrease as a result of the proposed permit revisions, the original determination, that the soils and vegetation would not be adversely affected, remains valid. In addition, as demonstrated in the air quality modeling analysis for CO, the emissions from the CORE Permit Revision would not exceed the NAAQS. Thus, the proposed project revisions are not predicted to adversely affect soils and vegetation.

D. Construction and Growth Analysis

The original applications provided a discussion of the emissions impacts resulting from residential and commercial growth associated with construction in the original applications. This analysis indicated there would be no significant increase in workforce, residential

[15] Endangered Species Act Deposition Modeling Results and Discussion, Trinity Consultants, April 16, 2007.

growth, or commercial development that would produce secondary emissions increases as a result of the CORE Project.

The financial scope and growth impact of the proposed CORE Permit Revisions is projected to be about one percent of that of the CORE Project, and the Terminal Expansion Project, as currently permitted. Therefore, negligible additional growth-related air pollution impacts on the area surrounding the WRR are expected.

E. Visibility Analysis

Sections 160-169 of the CAA, as amended in August 1977, establish a detailed regulatory program to protect the quality of the air in regions of the United States in which the air is cleaner than required by the NAAQS to protect public health and welfare. One of the purposes of the PSD program is "to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value."

Under the PSD provisions, Congress established a land classification scheme for those areas of the country with air quality better than the NAAQS. Class I allows very little deterioration of air quality; Class II allows moderate deterioration; and Class III allows more deterioration than Class I or II. In all cases, the ambient concentrations cannot violate any of the NAAQS. Certain existing areas were designated as mandatory Class I areas, precluding redesignation to a less restrictive class in order to acknowledge the value of preventing deterioration of air quality in these areas. Class I areas include International Parks, National Wilderness Areas and National Memorial Parks in excess of 5,000 acres and National Parks in excess of 6,000 acres.

In order to trigger the need for a Significant Impact analysis for either CO or VOM emissions increases, a "modified source would have to reside within 100 km of a Class I area." [16] There are no Class I areas located within 100 km of the WRR. Therefore, it is not necessary to evaluate the potential impact of the proposed project's emissions of CO and VOM on any Class I areas.

The Illinois EPA's guidance document does require a Significant Impact analysis for some pollutants (PM_{10}, SO_2, and NO_2) if a Class I area is located within 200 to 300 km of the facility being modified. The requested revisions to the CORE Permit Revision and to the Terminal Permit Revision do not change the conclusion that the projects do not trigger a significant net emissions increase for any of these three pollutants. WRR has reviewed the original Class I visibility analysis for the projects for these pollutants. The only Class I area located within 300 km of the WRR is the Mingo National Wildlife Refuge in southeastern Missouri. The U.S. Fish and Wildlife Service (USFWS) acts as the Federal Land Manager (FLM) for this area, which is located approximately 193 km (120 miles) southwest of the WRR. In 2006, as documented in the original CORE Permit application to the Illinois EPA, the USFWS did not require any visibility analysis of the impacts of the

[16] Prevention of Significant Deterioration: The Art and Science of PSD Air Quality Analysis, The Modeling Perspective, Illinois EPA, Revised February 27, 2014.

projects, CO and VOM emissions increases on the Mingo Class I area, nor did they request any further review of the applications for the projects as no visibility impacts were expected.[17] As the proposed CORE Permit Revision and the proposed Terminal Permit Revision only further reduces the CO and VOM emissions increase from the initial projects, and emissions of PM_{10}, SO_2, and NOx continue to show a net decrease, the determination that no visibility analysis is required remains valid.

While quantitative analyses of plume visibility at locations in Class II areas can be conducted using the USEPA's approved screening model for visibility impacts, VISCREEN, the original permit applications overall indicated decreases in the emissions of the WRR of visibility affecting pollutants (PM, NO_x, and Primary Sulfates); therefore, no degradation of visibility was predicted. Similarly, no visibility degradation from the proposed permit revisions is predicted.

VIII. NON-ATTAINMENT NEW SOURCE REVIEW (NA NSR)

A. Introduction

The WRR and the Terminal are both major stationary sources located in an area classified as marginal non-attainment for the 8-hour ozone standard. The emissions increases and decreases associated with the original CORE Project at the WRR, and the related Terminal Expansion Project, were significant for VOM since the net emission increases for the projects were greater than 40 tpy. Consistent with the USEPA Guidance for permit revisions, the emissions associated with the new or modified units added with the proposed CORE Permit Revision and the Terminal Permit Revision have been evaluated for permitting purposes as if they had been part of the original NA NSR permit. Therefore, NA NSR review for VOM emissions in accordance with the applicable requirements of 35 IAC Part 203 Subpart C, has been completed for the emission units being newly added as part of the CORE Permit Revision.[18]

For a major project, NA NSR requires: 1)"emission limits" for the nonattainment area pollutant that represents LAER, 2) compensating emission reductions from other sources, commonly called offsets, 3) information confirming that other existing major sources owned by the applicant within Illinois are in compliance with applicable air pollution regulations or on a program to come into compliance, and 4) an analysis of alternatives to the project.

B. LAER

The original CORE Project, together with the Terminal Expansion Project, triggered NA NSR permitting requirements for VOM emissions since the WRR and the Terminal are located in an ozone nonattainment area and the net emissions increase was determined to be significant. Therefore, the VOM emitting units that would be newly added or modified

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[17] April 26, 2006 telephone conference between Mr. Bill Roth-Evans of Trinity Consultants and Ms. Meredith Bond, Deputy Chief, Branch of Air Quality, U.S. Fish and Wildlife Service.

[18] While NO_x is an ozone precursor pollutant in an ozone nonattainment area, the proposed CORE Permit Revision and the Terminal Permit Revision do not change the original CORE permit conclusion that an overall net emissions decrease occurs for NO_x, eliminating any applicability of NA NSR for NO_x.

as part of the CORE Permit Revision and the Terminal Permit Revision must meet LAER.

LAER is the most stringent emission limitation derived from either of the following:

- The most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or
- The most stringent emission limitation achieved in practice by such class or category of source.

The most stringent emission limitation contained in a State Implementation Plan (SIP) for a category of source must be considered LAER unless either a more stringent emission limitation has been achieved in practice or the applicant is able to demonstrate that the SIP limitation is not achievable in this case. In addition, LAER cannot be less stringent than any applicable NSPS requirement.

A demonstration of LAER was provided in the permit application for VOM emissions from the various emission units that would be added in the proposed CORE Permit Revision and the Terminal Permit Revision. The Illinois EPA's proposed determinations of LAER are discussed in Attachment 5. The draft permits include proposed LAER requirements and limits for VOM emissions. These proposed limits have generally been determined based on the following:

- Emission data provided by the applicant;
- The demonstrated ability of similar equipment to meet the proposed emission limits or control requirements;
- Compliance periods associated with limits that are consistent with guidance issued by USEPA;
- Emission limits that account for normal operational variability based on the equipment and control equipment design, when properly operated and maintained; and
- Review of emission limits and control efficiencies required of other similar facilities and emission units as reported in the Clearinghouse.

C. <u>Emission Offset Requirements</u>

For major projects, Illinois NA NSR rules require emission offsets. VOM offset credits were initially acquired for the VOM emissions increases for the project. The aggregate VOM emissions from the CORE Permit Revision and the Terminal Permit Revision are less than the VOM emissions addressed by the original permits. Therefore, no additional emission offsets for VOM are required for the permit revisions, nor do the proposed permit revisions alter the amount of compensating emission offsets the project must obtain.

D. <u>Existing Source Compliance</u>

For major projects, Illinois NA NSR rules require that the owner or operator shall demonstrate that all major stationary sources which he or she owns or operates in Illinois are in compliance, or on a schedule for compliance, with all applicable state and federal air pollution control requirements. Moreover, any schedule for compliance must be federally enforceable or contained in an order of the Illinois Pollution Control Board or a court decree.

WRB, Phillips 66 Carrier, and Phillips have all submitted certifications that all major sources either owned or operated by such entity, respectively, that are located in Illinois are either: (1) currently in compliance with all applicable state and federal air pollution control requirements; (2) are subject to schedule(s) of compliance contained in a court decree, i.e., Consent Decree, *United States of America, State of Illinois, State of Louisiana, State of New Jersey, Commonwealth of Pennsylvania, Northwest Clean Air Agency v. Phillips 66 Company, WRB Refining LP, Monroe Energy, LLC,* Civil Action No. H-05-258, Entered Dec. 5, 2005, including subsequent amendments (Consent Decree); or (3) will be covered by federally enforceable limitations in the CORE Permit Revision or in the Terminal Permit Revision, and such federally enforceable limitations shall resolve any potential non-compliance. See also Attachment 2 for additional details.

E. Analysis of Alternatives

Applicants seeking to construct a major modification subject to NA NSR must analyze alternatives to the proposed source. In particular, Illinois NA NSR rules require that the applicant demonstrate the benefits of the project significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification, based upon an analysis of alternative sites, sizes, production processes, and environmental control techniques.

As discussed for the original CORE permitting effort, it is significantly more difficult to construct a new “green field” refinery than to modify an existing refinery due to the growing cost of equipment and the need for access to pipelines and other methods of raw material and product transportation. In fact, a new major refinery has not been constructed in the United States since 1976. Therefore, it was not practical to locate the CORE Project or the Terminal Expansion Project at an alternate site. This conclusion remains valid given the overall VOM emissions reductions with the proposed permit revisions.

Regarding the requirement to consider different sizes of equipment in relation to proposed projects in nonattainment areas, the equipment sizing in the proposed CORE Permit Revision and the Terminal Permit Revision must correspond with the original project design. It would be inconsistent with the original project to reduce the size of the new and modified equipment proposed to complete this project in the permit revisions.

IX. CONSULTATIONS FOR THE PROJECTS

A. Federal Endangered Species Act

As required under the federal Endangered Species Act (ESA), an assessment was completed for the original CORE Project and the Terminal Expansion Project. The report concluded that endangered species would not be affected. Emissions of CO, VOM, PM, and NO_x from the proposed CORE Permit Revision and the Terminal Permit Revision will all decrease from the levels originally permitted. USEPA Region 5 concurred that the original ESA assessment, previously accepted by USEPA, remains valid since the proposed changes will decrease emissions.[19] Therefore, no further analysis is required and the ESA consultation requirement for the proposed permit revisions has been fulfilled.

B. Illinois Endangered Species Act

Consultation with the Illinois Department of Natural Resources (Illinois DNR), as required under Illinois' Endangered Species Protection Act (ESA), has been initiated by Illinois EPA. The original ESA assessment showed no expected impacts on any identified threatened or endangered species. Because the proposed permit is a revision to the original CORE Permit and because emissions will decrease as a result of this revision, the results of the original ESA report remain valid. The proposed construction permit will be issued only after Illinois DNR has concluded that endangered species are unlikely to be affected by the proposed permit revisions.

C. National and State Historic Preservation Acts

Phillips has evaluated the potential effects of this permit action on historic properties eligible for inclusion in the National Register of Historic Places consistent with the requirements of the National Historic Preservation Act. There were no historic properties located within the Area of Potential Effects of the proposed projects. A letter summarizing this assessment was provided to the State Historic Preservation Officer for consultation and concurrence with this determination, with a copy to USEPA. Both the State Historic Preservation Officer and USEPA have provided concurrence on the determination that proposed issuance of the permit revisions will not affect historic properties eligible for inclusion in the National Register of Historic Places.[20]

X. DRAFT PERMITS

The Illinois EPA has prepared draft revised construction permits that it proposes to issue for the CORE Permit Revision and the Terminal Permit Revision. The conditions of the revised permits set forth the emission limits and air pollution control requirements that must be met. Illinois EPA is accepting comment only to the extent that this permit revises such limitations or adds new limitations.

The permits also establish enforceable limitations on the amount of emissions based on the proposed revisions. In addition to annual limitations on emissions, the permits include short-term emission limitations and operational limitations, as needed to provide practical enforceability of the annual emission limitations. As previously noted, actual emissions from the CORE Permit Revision and the Terminal Permit Revision will be less than the permitted emissions to the extent that the equipment is operated at less than capacity and control equipment

[19] September 30, 2013 email from Rachel Rinehart, USEPA Region 5, to Kristine Davies, Trinity Consultants.

[20] Letter to Anne Haaker, IHPA, from Genevieve Damico, USEPA, dated May 30, 2014, and Letter to Brian Wulf, Wood River Refinery from Anne Haaker, IHPA, dated June 4, 2014.

normally operates to achieve emission rates that are lower than the applicable standards and limits.

The permit revisions also establish appropriate compliance procedures for the ongoing operation of the WRR and the Terminal, including requirements for emission testing, required work practices, operational and emissions monitoring, recordkeeping, and reporting. For the new boiler, continuous emissions monitoring will be required for NO_x, CO, and carbon dioxide (CO_2). Refinery fuel gas (RFG) fed to the boiler must also be continuously monitored for H_2S concentration. Testing of emissions or performance testing would be required for emissions of other pollutants from these emission units and for other emission units at the WRR and the Terminal. These measures are imposed to assure that the operation and emissions of the WRR and Terminal are appropriately tracked to confirm compliance with the various limitations and requirements established for individual emission units.

XI. REQUEST FOR COMMENTS

It is the Illinois EPA's preliminary determination that the applications for the proposed CORE Permit Revision and the Terminal Permit Revision meet applicable state and federal air pollution control requirements. The Illinois EPA is therefore proposing to issue revised construction permits for these projects.

Comments are requested on the proposed revisions to these permits by Illinois EPA and on the conditions related to the proposed revisions.

Attachment 1
Glossary of Refinery Processes, Equipment, and Other Terms

Benzene Extraction Unit – BEU – A refinery process unit that removes benzene from naphtha streams prior to blending these streams into gasoline products.
Blowdown – Small quantities of steam condensate, cooling tower water, or other water streams sent to the wastewater system to prevent excessive accumulation of salts or other contaminants. Blowdown is typically accompanied by makeup, adding fresh water or steam to replace the blowdown.
Coke Drum – The vessel in the coker in which petroleum coke is formed.
Coke Drum Overhead Pressure – The pressure inside a Coke Drum, as measured on the vapor line of the coke drum during the coke steaming and quenching operations prior to venting of the coke drum.
Coker – A refinery process unit that uses heat and pressure to further separate the heavier streams that have been cracked in a FCCU into lighter, more valuable, materials such as hydrocarbon gases, naphtha, light and heavy gas oils, and petroleum coke.
Cracked Gas Plant – A treatment unit that uses sodium hydroxide or caustic to remove sulfur from naphtha streams prior to blending the stream into gasoline products.
Catalytic Reformer – CR – A refinery unit that increases the octane of streams by removing hydrogen, making "reformate" molecules.
Crude Oil – Crude – Unrefined naturally occurring petroleum composed of an assortment of hydrocarbons.
Cooling Water Tower – CWT – A device that utilizes the cooling from water evaporation to remove heat from hot water to produce cold water that can be used in various process units for cooling.
Delayed Coker Unit (or Coker) – DCU – A refinery process unit that converts heavy oils into hydrocarbon gas, naphtha, and petroleum coke. This is done by cracking long-chain hydrocarbon molecules into shorter molecules at high temperature and pressure.
Distillate – Distillate can include various petroleum hydrocarbon ranges, but is commonly used to refer to diesel products.
Distilling Unit – DU – The first step in petroleum refining in which incoming crude oil is heated and then separated into various fractions of different boiling ranges in distillation columns.
Fluidized Catalytic Cracking Unit – FCCU – A refinery process that converts heavy oils to gasoline, olefins, and other byproducts in the presence of a catalyst, high temperature, and pressure.
Flare Gas Recovery System – FGRS – A system that recovers gases that would normally be routed to a flare into the refinery's fuel gas system.
Fractionation – A separation process in which a substance is divided during a phase transition in to a number of smaller fractions in which the composition varies according to vapor pressure.
Heavy Gas Oil – A heavy fraction of petroleum that commonly is further processed in catalytic cracking units to produce the base for products such as gasoline and diesel fuel.
Hydrocarbon – A molecule containing primarily hydrogen and carbon.
Leak Detection and Repair – LDAR – A program in which piping and equipment in gas or light hydrocarbon service are regularly checked for leaks using a handheld instrument to identify the presence of and measure levels of hydrocarbon vapors so that leaks are identified quickly and repaired.

Lighter Oils – A lighter oil component of petroleum that commonly is further processed by fractionation to produce the base for products such as gasoline.
Quenching – Cooling of material or article through flooding or immersion with water or other liquids.
Quench Water – Water used to cool coke after it is formed in a coke drum.
Quench Water Fill and Soak Time – The duration of time between the commencement of the initial addition of quench water to a coke drum after discontinuing the steam sweep and final draining of quench water from the coke drum after opening the steam vents.
Refinery Fuel Gas – RFG – Byproduct gases from the refining process that are recovered for use as a fuel in refinery process heaters and boilers; composed mainly of methane (CH_4), similar to natural gas.
Straight Run Deisobutanizer Column – A fractionation column used to separate isobutane and other lighter components from straight run gasoline streams. Straight run gasoline is produced directly from the distillation units and not from cracking processes.
Sulfur Recovery Unit – SRU – A treatment process at the refinery that removes H_2S from RFG streams prior to its use as fuel in refinery process heaters and boilers.
Wastewater Treatment Plant – WWTP – A facility that processes wastewater to remove contaminants from water before it is discharged.

Attachment 2
Other Changes in the CORE and Terminal Permits

1. SO_2 Emission Estimation Methodology (See Permit Condition 2.1.a.ii. and the SO_2 limitations in Permit Conditions 4.1.6, and 4.7.6)

The CORE Permit Revision addresses changes to the manner in which SO_2 emissions for all of the refinery boilers and process heaters included in the CORE Permit that burn RFG are quantified. All the heater and boiler SO_2 emissions listed with the CORE Permit have been revised to reflect SO_2 emissions as a function of total sulfur content rather than just H_2S content, as was originally calculated.[21] Additionally, as certain CORE permitted units have come online, it has been determined that overall sulfur content of the fuel gas increased with the processing of the crudes. The increase in RFG sulfur concentration results in an increase in SO_2 emissions from combustion of RFG throughout the refinery. The updated SO_2 emission data in this permit revision reflects both the increase attributable to higher sulfur in the crude oil and the increase from the change in H_2S content to total sulfur content. With these two changes, the CORE Permit Revision still does not trigger PSD permitting for SO_2. The proposed CORE Permit Revision will contain federally enforceable limitations that will resolve potential non-compliance with respect to emissions of SO_2 from refinery heaters and/or boilers at the WRR.

2. Wastewater Treatment Plant (WWTP) Emission Limit (See Permit Conditions 3.4.3(b), 4.10.3, and 4.10.6)

The VOM increases associated with the original CORE Project were properly quantified and included in the original CORE Permit (i.e., 44.4 tpy). However, the overall VOM emission basis for the WWTP in the original CORE Permit was incorrect. This error was caused by inadvertently including only the concentration of speciated (individually identified) VOM compounds to calculate wastewater emissions from a partially-speciated VOM analysis. Accounting for both the identified and unidentified VOM compounds in the wastewater results in pre-CORE wastewater emissions of 149.5 tpy rather than 40.3 tpy. Revised post-CORE total wastewater VOM emissions are 149.5 tpy pre-CORE plus the 44.4 tpy increase from the CORE Project for a total of 194.0 tpy. The emission limits for the entire wastewater treatment system were moved to Section 3.4, for consistency with other existing sources that were not physically modified, but experience an increase in emissions from the project. Emission limits for the new and modified wastewater treatment units subject to LAER remain in Section 4.10 and details regarding applicable regulations were added.

The proposed CORE Permit Revision will contain federally enforceable limitations that will resolve potential non-compliance with respect to emissions of VOM from emission units and/or activities in the WWTP at the WRR.

3. CR-2 Associated Emission Increase to CR-1 (See Permit Condition 3.4.1)

When the original CORE Permit was issued, WRR operated three reforming units (CR-1, CR-2, and CR-3). At that time, it was anticipated that CORE associated emission increases would be realized from additional operation and

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[21] That approach was consistent with New Source Performance Standards for Petroleum Refineries, 40 CFR 60 Subpart J.

firing of the process heater at CR-2 and CR-3. WRR has subsequently elected to permanently shut down CR-2. As a consequence, the associated emissions increase attributed to CR-2 are being re-allocated to CR-1 in this CORE Permit Revision to accurately represent the associated emission increases from the CORE Project. Physical modification of CR-1 heaters was not required to facilitate this change. The associated emissions increase at CR-3 included in the original CORE Permit was not affected by this change. The proposed CORE Permit Revision will contain federally enforceable limitations that will resolve potential non-compliance with respect to emissions from CR-1 at the WRR.

4. Fugitive Emissions of H_2S and TRS (See Permit Condition 4.3.6(c))

Fugitive or uncaptured emissions of H_2S and TRS were not quantified in the original CORE application or explicitly addressed in the CORE Permit. The proposed CORE Permit Revision is based on negligible emissions of H_2S and TRS from the affected components. Fugitive emissions of H_2S and TRS are calculated based on typical concentrations in raw material, intermediate, and product streams, consistent with emissions calculation methodology for fugitive VOM emissions. For this purpose, emissions of H_2S and TRS shall not exceed 0.3 and 0.5 tons/year, respectively.

5. Total Dissolved Solids (TDS) and VOM Calculation Methodology for Cooling Towers (See Permit Condition 4.4.6)

The existing TDS limits for CWT-15, CWT-23, CWT-24, and CWT-25 require that WRR restrict the number of times that water is recirculated through the cooling tower, which increases water usage. Revising the TDS limits will allow for significant water reuse and conservation. The annual average TDS limit for CWT-15, CWT-23, CWT-24, and the SRU CWT-25 are being revised from 2,000 ppm to 2,520 ppm to allow WRR to lower water usage and wastewater discharge volume by over 100,000 gallons per day. Additionally, since the cooling towers are now subject to the heat exchange system requirements of 40 CFR 63 Subpart CC, which require routine monitoring using the El Paso method, the VOM emission limits have been revised to be consistent with expected VOM emissions calculated using this method. No physical change is being made to cooling towers CWT-15, CWT-23, CWT-24, or CWT-25.

6. Carbon Monoxide Emissions During Process Heater and Boiler Startup (See Permit Conditions 4.1.3(e)(ii) and 4.12.3(d)(ii))

Process heaters and boilers must periodically be shut down for inspection maintenance and repair of this equipment or the associated process unit. During subsequent startups, it is possible that these heaters and boilers will exceed the limit in 35 IAC 216.121 (i.e., 200 ppm CO corrected to 50 percent excess air). Therefore, WRR is being provided authorization pursuant to 35 IAC Part 201 Subpart I for heaters and boilers to replace the standards in 35 IAC 216.121 with work practices during startup. WRR has a written startup procedure in place for each boiler and fired heater. The procedures include pre-ignition functional checks and follow best practices and manufacturer recommendations to avoid inefficient combustion during startup and to minimize startup duration.

7. Contemporaneous Netting Updates (See Permit Attachment 2)

As part of a 2005 Consent Decree with the United States, the State of Illinois and others (*United States of America, State of Illinois, State of*

Louisiana, State of New Jersey, Commonwealth of Pennsylvania, Northwest Clean Air Agency v. Phillips 66 Company, WRB Refining LP, Monroe Energy, LLC, Civil Action No. H-05-258, entered Dec. 5, 2005, including subsequent amendments), WRR agreed to reduce NO_X emissions from heaters and boilers at the WRR. All such reductions were required to be completed by December 31, 2012. Within the Consent Decree, WRR was provided flexibility to choose which heaters and boilers it would retrofit with controls and/or shutdown. Per the 2005 Decree, NO_X, SO_2, PM, VOM, and CO emission reductions realized as a function of installing Decree-required NO_X controls cannot be used for netting. NO_X emission reductions from the installation of Decree-based NO_X controls were not used for netting in the original CORE Permit. However, small decreases in SO_2, PM, VOM or CO were included in the original netting exercise. The revised netting analyses remove these decreases. Removal of these decreases does not change the overall conclusions of netting analysis. The affected heaters are:

- HTR-KHT;
- HTR-BEU-HM1;
- HTR-BEU-HM2;
- Boiler 16;
- HTR-VF1-North; and
- HTR-VF1-South.

In addition to the netting adjustment discussed above, the netting analysis has been updated to add projects permitted since the original CORE Permit was issued.

8. Hydrogen Plant (HP-2) blowdown and High Pressure Stripper (HPS) Vents (See Permit Section 4.13)

The Hydrogen Plant that was constructed as part of the CORE Project uses "closed technology" that eliminates continuous venting that was often present with older technology. Because of the presence of the "closed technology", during the original CORE design, WRR initially assumed there would never be vent emissions from HP-2. However, the WRR has since determined there are some operating scenarios that require venting from blowdown and the HPS vents to maintain safe and/or stable operation during startup, shutdown, and malfunction. This proposed CORE Permit Revision includes HP-2 vent emissions from such potential startup, shutdown or malfunction events. The VOM and GHG emissions from the HP-2 blowdown and HPS vents are minimal. The proposed CORE Permit Revision will contain federally enforceable limitations that will resolve potential non-compliance with respect to emissions from the HP-2 blowdown and High Pressure Stripper (HPS) vents at WRR. See also Attachments 4 and 5 for additional details.

9. Requirements for Delayed Coker Unit No. 2 (DCU-2) (See Permit Section 4.14)

After the initial CORE Permit was issued, the USEPA alleged that the Permittee had failed to adequately evaluate Coker VOM, PM, TRS and H_2S emissions in the 2006 permit application and had failed to (i) install proper control technology, (ii) take appropriate limitations, and/or (iii) engage in appropriate work practices to limit emissions from the Coker. The Permittee entered into a 3rd Amendment to the Consent Decree that included a testing program to establish BACT and/or LAER equivalent controls that would apply to the Coker beginning upon completion of the testing program. These controls and/or work practice standards are included below.

- Coke Drum Overhead pressure is to be reduced to 2 psig or less prior to discharging the coke drum steam vent to the atmosphere;
- Quench water fill and soak time is to be a minimum of 5.75 hours;
- All components and pieces of equipment within the Quench Water System, except the Quench Water Tank are maintained as a hard-piped system with no emission points to atmosphere;
- Quench water make-up is allowed only from the following units:
  - Water that is fresh (i.e., water brought into WRR that has not been in contact with process water or process wastewater);
  - Non-contact cooling water blowdown;
  - Water that has been stripped in a sour water stripper; or
  - Some combination of water from the above mentioned sources.
- Water from the second half of the quench cycle may be used for quench water make-up during malfunction of:
  - Any of the following four Sour Water Strippers: DU-2 sour water concentrator (V-3974), cracked gas plant sour water concentrator (V-3318), Distilling West sour water stripper (V-1713), and sulfur plant sour water stripper (V-18600); or
  - Any of the following four Sour Water Tanks: Tank M65, Tank 80-6, Tank 1714, and Tank F72; and
- Oily sludge, oily wastewater, biosolids, or other wastes is not to be fed to any coke drum during the quench cycle.

The July 10, 2013 letter from Phillip Brooks, USEPA Region 5 Air Enforcement Division Director to Tim Goedeker, Phillips 66 Consent Decrees Program Manager, approved the operational controls as equivalent to LAER, fulfilling the requirement of Paragraph 259Q of the Consent Decree, with the exception of incorporating them in a federally enforceable permit. The proposed CORE Permit Revision fulfills this permitting obligation.

In addition, emission limits for DCU-2 drum operations have been included in the proposed CORE Permit Revision.

10. Specification of an Averaging Period for Certain Limitations (See Permit Sections 4.1.5 and 4.8.5)

Emission limitation averaging periods were added to Permit Sections 4.1.5 and 4.8.5 for the Process Heater BACT/LAER limits and Sulfur Recovery Unit (SRU) BACT/LAER limits, respectively, to indicate that compliance with these limits is based on three 1-hour average stack tests, or on a 30-day rolling average basis where monitored continuously using a continuous emissions monitoring system (CEMS).

11. Removing References to Equipment Eliminated in the Permit Revisions

Provisions or references pertaining to equipment eliminated from the CORE and Terminal Expansion Project, including references to Distilling West Cracked Gas Plant, FCCU-3, CWT-3, and Tanks A-098 and A-099 in the CORE Permit, and to loading rack modifications and Tanks 209, 210, and 2002 in the Terminal Expansion Permit, were removed in the permit revisions. Permit Section 4.2 of the CORE Permit, which dealt with the Distilling West Cracked Gas Plant, was deleted in its entirety.

12. Miscellaneous CORE Permit Revision Clarifications

- Updating the CORE Permit Permittee name from ConocoPhillips Wood River Refinery to Phillips 66 Wood River Refinery.
- Where the Consent Decree is cited, adding "and any court-approved amendments as of September 21, 2012."
- Updating the Process Heater, FCCU, Flare, and SRU sections to reflect that these units are now subject to current versions of 40 CFR Part 60 Subpart Ja and 40 CFR 63 Subpart DDDDD, as applicable.
- Updating nomenclature for cooling towers from CW23 and CW24 to CWT23 and CWT24.
- Eliminating Permit Conditions 4.7.3(e) and 4.7.5-1.a.iv regarding NSPS Ja limits for delayed coking units to indicate that the delayed coking unit may be vented to atmosphere after it is depressured to 5 psig or less using an enclosed blowdown system vented to a fuel gas system, fuel gas combustion device, or flare. These requirements are now covered in Section 4.2, Delayed Coker Unit 2.
- Removing an erroneous reference to Permit Condition 3.3.1, which deals with NSR applicability, from Permit Condition 4.11.3(c) that pertains to the State Standards for fugitive particulate matter emission from roadways.
- Correcting permit attachment "Procedures for Calculating CO and VOM Emissions from New Flares" to a Lower Heating Value rather than Higher Heating Value basis to reflect parameters as monitored.
- Removing requirement formerly in Condition 4.7.10.d.i to include summary of Root Cause Analysis for flares with periodic compliance reports given this condition requirement is redundant to reporting requirements in Condition 4.7.10(e).

13. Miscellaneous Terminal Permit Revision Clarifications

The Terminal Permit Revision includes administrative corrections to update the facility owner and operator names, and references to Tank 2003. With the removal of the proposed new loading rack in the original Terminal Permit, an associated de minimus emission increase has been included for diesel loading at the existing rack.

Attachment 3
Regulations Applicable to New and Modified Emission Units

Emission Unit	Regulation	Citation	Key Requirements[1]
Boiler 19	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters	40 CFR 63 Subpart DDDDD	Initial energy assessment and annual tune-up [40 CFR 63.7549]
	New Source Performance Standards for Small Industrial, Commercial, and Institutional Steam Generating Units	40 CFR 60 Subpart Db	PM – 0.1 lb/mmBtu and opacity 20%; NOx emissions no more than 0.20 lb/mmBtu 30-day average, performance testing, monitoring, recordkeeping, and reporting requirements. [40 CFR 60.44b(i) and 60.44b(l)(1)]
	New Source Performance Standards for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	40 CFR 60 Subpart Ja	Fuel gas H_2S not to exceed 162 ppm 3-hr average or 60 ppm 365 day; complete RCA and CA for exceedances, monitoring, recordkeeping, and reporting requirements. [40 CFR 60.102a-108a]
	Emission Standards and Limitations for Visible Emissions from Stationary Sources	35 IAC 212.122(a)	Opacity limit of 20%
	Emission Standards and Limitations for Carbon Monoxide from Fuel Combustion Emission Sources	35 IAC 216.121	CO limit of 200 ppm, corrected to 50% excess air
	Emission Standards and Limitations for Nitrogen Oxides Emissions from Industrial Boilers	35 IAC 217 Subparts E and U	NOx emissions no more than 0.08 lb/mmBtu 30-day average, monitoring, recordkeeping, and reporting.[35 IAC 35 217].
Tanks A-037, A-037	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	40 CFR 60 Subpart Kb	Floating roof with double seal or closed vent control, maximum vapor pressure limit 11.1 psig, submerged loading pipe, operating practice, inspection, recordkeeping and reporting. [40 CFR 60.112b]
	National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries	40 CFR 63 Subparts CC and A	Similar requirements as 40 CFR 60 Subpart Kb [40 CFR 63.646 and 40 CFR 63.119-123]

Emission Unit	Regulation	Citation	Key Requirements[1]
Terminal Tank 2003	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	40 CFR 60 Subpart Kb	Floating roof with double seal or closed vent control, maximum vapor pressure limit 11.1 psig, submerged loading pipe, operating practice, inspection, recordkeeping and reporting. [40 CFR 60.112b)
	National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)	40 CFR 63 Subpart R	Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart that is also subject to applicable provisions of 40 CFR 60 Subpart Kb or XX of this chapter shall comply only with the provisions in each subpart that contain the most stringent control requirements for that facility. [40 CFR 63.420(g)]
	National Emission Standards for Hazardous Air Pollutants for Organic Liquid Distribution (Non-Gasoline)	40 CFR 63 Subpart EEEE	Compliance with 40 CFR 60 Subpart Kb per 40 CFR 63.2396(a) except records must be retained for 5 rather than 2 years. [40 CFR 63.2346]
	Organic Material Emission Standards and Limitations for the Metro East Area for Storage Containers of Volatile Petroleum Liquid	35 IAC 219 Subpart B	Similar requirements as 40 CFR 60 Subpart Kb [35 IAC 219.121(b)(1)]
Refinery Fugitive Components	New Source Performance Standards for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	40 CFR 60 Subpart GGGa	LDAR program to monitor valves, pumps, PRVs, connectors, and compressors in light liquid and gas service. Heavy liquid valves require visual monitoring. Monitoring frequency, leak thresholds, repair and retest schedule, recordkeeping and reporting are also established. [40 CFR 60.592a]
	Organic Material Emission Standards and Limitations for the Metro East Area for Petroleum Refining and Related Industries; Asphalt Materials	35 IAC 219 Subpart R	Similar requirements as 40 CFR 60 Subpart GGGa [35 IAC 219.445-452]
	National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries	40 CFR 63 Subparts CC and A	Equipment leaks that are also subject to the provisions of 40 CFR 60 Subpart GGGa, are required to comply only with the provisions specified in 40 CFR 60 Subpart GGGa. [40 CFR 63.640(p)(2)]

Emission Unit	Regulation	Citation	Key Requirements[1]
Terminal Fugitive Components	National Emission Standards for Organic Liquid Distribution (Non-Gasoline)	40 CFR 63 Subpart EEEE	Comply with the requirements for pumps, valves, and sampling connections in 40 CFR 63 Subpart TT (control level 1), Subpart UU (control level 2), or Subpart H. [40 CFR 63.2346 and Table 4, Item 4]
	National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)	40 CFR 63 Subpart R	Monthly leak inspection incorporating sight, sound, and smell, a log book documenting inspections, repair schedule, and operating practices to avoid gasoline exposure to atmosphere. [40 CFR 63.424]
	Organic Material Emissions Standards and Limitations for the Metro East Area for Organic Emissions from Miscellaneous Equipment	35 IAC 219.142	No more than 2 cu. in. of volatile organic liquid may be discharged from a pump or compressor in any 15 minute period at standard conditions.
Cooling Water Tower CWT-26	National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries	40 CFR 63 Subpart CC	Monthly leak monitoring of CWT return stream using the El Paso Method, repair schedule, recordkeeping, and reporting requirements. [40 CFR 63.654]
	Organic Material Emission Standards and Limitations for the Metro East Area for Other Emission Units	35 IAC 219 Subpart TT, 219.986(d)	Similar requirements as 40 CFR 63 Subpart CC
Hydrogen Plant 2 Vents	Organic Material Emission Standards and Limitations for the Metro East Area for Petroleum Refining and Related Industries; Asphalt Materials	35 IAC 219 Subpart R	Vents to atmosphere over 8 lb/hr must be controlled to reduce organic material by at least 85%. [35 IAC 219.441(c)(1)]
Existing Distilling Flare	New Source Performance Standards for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	40 CFR 60 Subpart Ja	Flow and TRS monitoring; RCA and CA for flaring >500 lb/day SO_2 or >500,000 scfd; 162 ppm H_2S limit; FMP, recordkeeping and reporting. [40 CFR 60.103a]

[1] Only a summary of Key Requirements is provided. Minor differences in threshold, reporting, and other details are not distinguished.

Key:

TRS = Total Reduced Sulfur

RCA = Root Cause Analysis

CA = Corrective Action

FMP = Flare Management Plan

Attachment 4

Discussion of Best Available Control Technology (BACT) for New Emission Units Emitting CO and GHGs

Table of Contents

4.0 Introduction

This attachment discusses the Illinois EPA's analysis of BACT and proposed determinations of BACT for the various subject emission units to be installed for the permit revisions.

The emission units for which BACT is required and the pollutants for which BACT must be established are summarized below:

- New Boiler – GHG and CO
- Hydrogen Plant Vents – GHG
- Fugitive Components – GHG

The five basic steps of a top-down BACT review procedure as identified by the USEPA in the October 1990, Draft New Source Review Workshop Manual are:

Step 1. Identify all control technologies.
Step 2. Eliminate technically infeasible options.
Step 3. Rank remaining control technologies by control effectiveness.
Step 4. Evaluate most effective controls and document results.
Step 5. Select BACT.

A 5-step BACT analysis is presented for each unit that would emit CO or GHG and that would be added or modified as part of the proposed CORE Permit Revision.

4.1 Boiler

An additional boiler, Boiler 19, is necessary to provide steam that would have been provided as a byproduct from FCCU-3, now removed from the CORE Permit Revision. (FCCU-3 will not be operated because the composition of crude oil that is now being supplied to WRR requires additional fractionation capacity rather than additional cracking capacity.) Boiler 19 will have a design capacity of 420 million British thermal units per hour (mmBtu/hr). It will fire RFG or natural gas, in the event that sufficient RFG is not available. The boiler will be designed to produce high pressure steam (600-700 psia), and will be connected to the existing high pressure steam header at the refinery.

4.1.1 Boiler GHG BACT

GHG emissions from the new boiler are due to the combustion of fuel. Over 99 percent of these emissions will be CO_2, due to the carbon in the fuel burned in the boiler. The boiler will also emit small amounts of CH_4 and nitrous oxide (N_2O).

Proposal

Phillips proposed the following as BACT for the boiler for GHG emissions.[22]

[22] Phillips also proposed that the fuel selected for the boiler, RFG and natural gas, be part of BACT for the boiler as natural gas and RFG are low-carbon fuels. However, the use of these gases as fuel for the boiler is part of Phillips' design for the CORE revisions. As such, the analysis did not reflect consideration of the possible use of other fuels as a measure to further control GHG emissions.

1. Energy efficient design and operation; and

2. Good combustion practices.

The Illinois EPA is proposing that the BACT technology for GHG emissions for the boiler be a combination of design, operational, and maintenance practices that enhance the thermal efficiency of the boiler, thereby lowering GHG emissions, and implementation of good combustion practices.

Step 1: Identify Available Control Technologies

The available control technologies for GHG emissions that Phillips identified for the boiler are as follows:

1. Energy efficient design and operation;

2. Good combustion practices; and

3. Carbon capture and sequestration (CCS).

Step 2: Eliminate Technically Infeasible Options

1. Energy Efficiency

Energy efficient design and good operational and maintenance practices will reduce the GHG emissions of the boiler. In particular, several design elements are technically feasible for the boiler for improved energy efficiency that reduce the amount of fuel that must be fired in the boiler to produce steam for the refining process and other steam needs at the facility. As a result, less CO_2 and other GHG will be emitted by the boiler. These energy efficient design elements are discussed below:

- Boiler Oxygen Trim Control – The exhaust stack oxygen level is monitored and the inlet air flow is managed to improve thermal efficiency.

- Boiler Economizer – A heat exchanger is used to transfer some of the heat from the boiler exhaust gas to the incoming boiler feedwater. Preheating the feedwater in this way reduces boiler heating load and increases thermal efficiency.

- Boiler Blowdown Heat Recovery – Periodically or continuously, some water in the boiler is removed to maintain water quality, i.e., avoid build-up of impurities in the water in the boiler. This blowdown is hot and can be productively used instead of being wasted. A heat exchanger is used to transfer some of the heat in the hot blowdown water for preheating feedwater, thereby increasing the boiler's thermal efficiency.

- Condensate Recovery – As steam from the boiler is used in the heat exchanger, it condenses. Hot condensate that is not returned to the boiler represents a loss of energy. Energy savings come from the fact that most condensate is returned at a relatively hot temperature compared to the cold makeup water. Accordingly, when the hot condensate is returned to the boiler to be reused as feed water, the boiler heating load is reduced and the thermal efficiency increases.

- Air Preheater – This device recovers heat in the boiler exhaust gas to preheat combustion air thereby resulting in a reduction in boiler heating load and an increase in thermal efficiency. Additionally, air preheaters may increase NOx emissions from the boiler by anywhere from 10 to 60 percent, depending upon the NO_X control measures that are present.[23,24]

- Good Maintenance – Proper maintenance practices such as keeping an established or vendor-recommended maintenance schedule for such things as cleaning and tune-ups reduces CO_2 emissions by preserving the thermal efficiency of a boiler.

Energy efficient design, operating and maintenance practices are feasible for the boiler.

2. Good Combustion Practices

Good combustion practices are relevant for GHG as they serve to improve the combustion efficiency of a boiler as they reduce emissions of CO_2 and as they directly serve to reduce emissions of CH_4. USEPA has relied on good combustion practices as the technology to address emissions of organic hazardous air pollutants from boilers in 40 CFR 63 Subparts DDDDD and JJJJJJ, the NESHAP for boilers and certain other fuel combustion units for major and area sources, respectively. Good combustion practices include a modern, combustion management system on a boiler to monitor and manage the level of oxygen in the flue gas and the flows of combustion air into a boiler for improved thermal efficiency. Good combustion practices are feasible for the boiler.

3. CCS

CCS would capture CO_2 from the boiler's flue gas and purify, compress, and transport this CO_2 to either a sequestration site or for use for Enhanced Oil Recovery (EOR). As a gas-fired boiler, the concentration of CO_2 in the flue gas from the boiler is low. As a dilute exhaust stream, CCS for the boiler presents a "significant and challenging technical issue that may not be readily suitable for CCS."[25] The boiler's flue gas contains nitrogen, oxygen and water, along with CO and other pollutants. CO_2 capture could be accomplished by scrubbing CO_2 from the flue gas with an appropriate liquid sorbent, solids sorbent, or membrane. To date, sorbent scrubbing of CO_2 has only been used commercially on a small (slip stream) scale, while solid sorbents and membranes are only in the research and development phase.[26] A number of post-combustion carbon capture projects have taken place on

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[23] Baukal, Charles E., Air Preheat Effects on NO_x. Retrieved from: http://industrialcombustion.net/files/2003_AWMA_Paper.pdf.

[24] The boiler will use an economizer rather than an air preheater because the two design features are mutually exclusive and an economizer does not contribute additional NO_x emissions.

[25] Report of the Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010.

[26] Plains CO_2 Reduction Partnership, Carbon Separation and Capture, http://www.undeerc.org/PCOR/newsandpubs/pdf/CarbonSeparationCapture.pdf

small, slip streams at coal-fired power plants. Although these projects have demonstrated the technical feasibility of small-scale CO_2 capture of a power plant's emissions using various solvent-based scrubbing processes, significant uncertainty remains in scaling these technologies up for cost-effective use.[27] These factors suggest that capture, and by extension, CCS is generally not a feasible control technology for the proposed boiler.[28]

With regard to technical feasibility of CCS for a proposed project, USEPA indicates in its GHG Permitting Guidance that:

> CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific consideration (e.g., access to suitable geological reservoirs for sequestration, or other storage option).
>
> GHG Permitting Guidance, pp. 35-36.

Phillips examined the use of pre-combustion systems, post-combustion systems and oxy-combustion as a means to produce a virtually pure CO_2 stream from the boiler that could be sequestered. Since the fuel for the boiler is RFG and natural gas, a pre-combustion system, like that used to produce a fuel gas or substitute natural gas at a coal gasification plant, are not applicable. Post-combustion systems that extract the CO_2 from the boiler flue gases are still in their development. Not only does the flue gas stream pose the same technical issues for capture of CO_2 as present for combustion of coal, but the concentration of CO_2 in the flue gas may be lower because natural gas and RFG have lower carbon contents than coal. Similarly, oxy-combustion, whereby a higher concentration of oxygen rather than air is combusted with a fuel to produce a flue gas stream containing higher concentrations of CO_2, is also in its early stages of development.

In addition, once a purified CO_2 stream is achieved, the following three challenges must be addressed before carbon sequestration can be safely and effectively deployed on the commercial scale.

- Permanent storage must be proven by validating that CO_2 will be contained in the target formations.

- Technologies and protocols must be developed to quantify potential releases and to confirm that the projects do not adversely impact underground sources of drinking water (USDWs) or cause CO_2 to be released to the atmosphere.

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[27] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p.32.
[28] When considering if a control technology is technically feasible, it must be applicable. A control technology is applicable if it can reasonably be installed and operated on the type of source under consideration. If a given technology has not been used on an emission unit, care should be given to transferring technology from similar gas streams with the same physical and chemical properties.

- Long term monitoring of the migration of CO_2 during and after project completion must be completed. Methodologies to determine the presence/absence of release pathways must be developed.

- Effective regulatory and legal framework must be developed for the safe, long term injection and storage of CO_2 into geological formations.

Various development projects are underway to address these challenges. They target coal-fired units and are facilitated by governmental funding so do not demonstrate that CCS is technically feasible for a gas-fired unit at a refinery.[29]

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Given the only feasible control options, improved energy efficiency and good combustion practices, would be required, a ranking of these technologies is not necessary.

Step 4: Evaluate the Most Effective Controls

Phillips will utilize energy efficient design and good combustion practices, so no further evaluation of these technologies is necessary.

With respect to CCS, as already discussed, a number of technological and practical challenges currently exist that result in CCS not being technically feasible for the boiler. In addition, CCS is very expensive. The annualized cost to capture, transport, and store CO_2 emissions from the boiler is $18 million. The annualized cost for the boiler and for the CORE Permit Revisions, including the boiler, $5.6 million and $14 million, respectively, are both less than the annual

[29] As discussed in a report prepared by the Congressional Research Service, Peter Folger, Carbon Capture: A Technology Assessment, Congressional Research Service, 7-5700, R41325, November 5, 2013, the feasibility of CCS as a BACT technology for fuel combustion units is also uncertain as a general matter because CCS is not yet a demonstrated technology for fuel combustion units. This report assesses prospects for improved, lower-cost technologies for each of the three current approaches to CO_2 capture: post-combustion capture; pre-combustion capture; and oxy-combustion capture. While all three approaches are capable of high CO_2 capture efficiencies (typically about 90%), the major drawbacks of current processes are their high cost and the large energy requirements for operation.
Another drawback in terms of their availability for GHG mitigation is that at present, there are still no full-scale applications of CO_2 capture on a coal-fired or gas-fired power plant (i.e., a scale of several hundred megawatts of plant capacity). To address the current lack of demonstrated capabilities for full-scale CO2 capture at power plants, a number of large-scale demonstration projects at both coal combustion and gasification-based power plants are planned or underway in the United States and elsewhere. Substantial research and development (R&D) activities are also underway to develop and commercialize lower-cost capture systems with smaller energy penalties. Current R&D activities include development and testing of new or improved solvents that can lower the cost of current post-combustion and pre-combustion capture, as well as research on a variety of potential "breakthrough technologies" such as novel solvents, sorbents, membranes, and oxy-fuel systems that hold promise for even lower-cost capture system. Carbon Capture: A Technology Assessment, p. i.

cost for CCS control.[30] The annualized cost of using CCS to control CO_2 emissions from the boiler would represent a 126 percent increase in the annualized cost for the CORE revisions. The cost-effectiveness of using CCS on an annuitized basis is estimated to be $105/ton CO_2 captured.[31] These cost impacts for control of CO_2 are deemed excessive.

Step 5: Select BACT

Previous BACT determinations for GHG for gas-fired boilers are listed in Table 4.1.1 below. None of the previous BACT determinations for GHG from boilers require add-on controls. GHG emissions are addressed by energy efficiency and good combustion practices. Phillips proposes the same control technologies.

Two BACT determinations, one for a boiler at an industrial facility proposed by Indiana Gasification and one for the boilers at the facility proposed by Ohio Valley Resources, directly address the energy efficiency of the boilers.[32,33] These determinations required that the boilers achieve thermal efficiencies, on a higher heating value basis, of 81 and 80%, respectively. However, the permits do not identify a specific means to verify compliance with these limits on an ongoing basis. Meanwhile, the Cargill permit contains an output based limit on CO_2 of 178 lb CO_2/1,000 lbs steam. The BACT limit in the proposed CORE Permit Revision includes an output based CO_2e limit.

The Illinois EPA is proposing the following technologies as BACT for GHG for the boiler:

1. Equipment design for energy efficiency, including the following: boiler economizer, condensate recovery, blowdown heat recovery, and good operating and maintenance practices.

2. Good combustion practices, including automated combustion management system with oxygen trim and inlet combustion air controls.

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[30] Phillips used cost information for CCS from the President's Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010. Annualized CCS and project costs are based on a 30 year equipment life, 7% interest rate from the OAQPS CCM Sixth Edition, and 12% inflation rate based on the Consumer Price Index from June 2007 to June 2013. Annualized costs were calculated by multiplying the estimated capital cost by the Capital Recovery Factor. The Capital Recovery Factor is calculated as: $I*(1+I)^n/[(1+I)^n-1]$ where I is the annual interest rate and n is the economic life of the equipment. See the Cost Manual developed by USEPA's Office of Air Quality Planning and Standards and Tables E-1a through E-1g of the CORE Permit Revision application for further details.

[31] The cost for CCS does not include the significant increase in purchased electricity needed to compress the CO_2. Annualized costs for the entire project and the boiler, alone, do include the incremental cost for natural gas needed to provide steam to the new fractionation columns, the only steam demand associated with the CORE Permit Revisions to CORE.

[32] The other BACT determinations were not informative. In general, BACT limitations are expressed in pounds per million Btu of heat input with emissions based on emission factors developed using the methodology in 40 CFR 98 based on fuel characteristics. As such, these BACT limits do not directly address the energy efficiency of the subject boilers.

[33] Incidentally, none of the determinations of BACT for other new boilers specified use of control technologies for GHG that are different than proposed for this new boiler. GHG emissions are controlled by good combustion practices.

The Illinois EPA is proposing that the BACT limit for GHG emissions from the boiler be 0.168 pounds CO_2e per pound steam output on an annual average. This reflects achievement of a thermal efficiency equivalent to 77 percent on a higher heating value basis taking into account the enthalpy of high pressure steam and heat loss due to boiler feed-water and boiler blowdown.[34] This thermal efficiency (equivalent to 85.2% thermal efficiency on a lower heating value basis) is typical over the life of an efficiently operated boiler equipped with an economizer, oxygen trim controls, and blowdown heat recovery.[35]

Table 4.1.1
Previous BACT Determinations for GHG from Gas-Fired Boilers

RBLC ID/ Permit No.	Facility, State	Date	Fuel and Capacity, mmBtu/hr	BACT Limit	BACT Technology[1]
AL-0271	Georgia Pacific, Alabama	6/11/14	NG, 425	CO_2e: 219,214 tpy, 1117.1lb/mmBtu	EED
IN-0180	Midwest Fertilizer, Indiana	6/4/14	NG, 218.6, 3 ea.	CO_2: 59.61 ton/mmcf 3-hr avg	EED, GCP
P0115063	PCS Nitrogen Ohio	1/17/14	NG, 227	CO_2e: 117,212 tpy, 12-mo. And other GHG based on AP-42, 3 1-hr performance tests	NG, EED, GCP
T147-32322-0062	Ohio Valley Resources, Indiana	9/25/13	NG, 218, 4 ea.	CO_2e: 59.61 ton/mmscf 3-hr avg, TF: 80%, HHV basis	GCP, fuel use limit
LA-0270	Phillips 66, Louisiana	9/16/13	NG, 375	CO_2e: 81.6 tons/mmlb steam, 12-mo.	EED, GCP
NE-0054	Cargill, Nebraska	9/12/13	NG, 300	CO_2e: 153,743 tpy, 12-mo. CO_2: 0.178 lb/lb steam, 12 mo.	GCP
IA-0106	CF Industries Nitrogen, Iowa	7/12/13	NG, 456	CO_2: 117 lb/mmBtu N_2O: 0.0006 lb/mmBtu, 3-tests CH_4: 0.0023 lb/mmBtu, 3-tests CO_2e: 234,168 tpy, 12 mo.	NG, proper operation
MN-0088	S. Minnesota Beet Sugar Coop, Minnesota	5/22/13	NG, 257.3	CO_2e: 117,800 tpy, 12-mo.	NG, EED, GCP
TX-0648	Invista, Texas	5/14/13	NG, 300 2 ea., 400 2 ea.	CO_2e: 1,371,711 tpy 12-mo. for all four units	GCP
LA-0266	Crosstex Processing, Louisiana	5/1/13	NG, 359	87.6 tons/mmlb steam, 12-mo.	EED, GCP

[34] Calculated as the difference in enthalpy between superheated steam (1,320 btu/lb at 660°F) and saturated water (46 btu/lb at 600 psig). This calculation also accounts for the heat loss due to heating boiler feedwater at 229°F to a saturation temperature of 490°F and boiler blowdown of 2% of steam produced. See Table B-5 of the application for further detail.

[35] See Table 5-3 of the application. The boiler will use an economizer rather than an air preheater because the two design features are mutually exclusive and an economizer does not act to increase NO_x emissions.

RBLC ID/ Permit No.	Facility, State	Date	Fuel and Capacity, mmBtu/hr	BACT Limit	BACT Technology[1]
LA-0272	Dyno Nobel, Louisiana	3/27/13	NG, 217.5	CO_2e: 55,986 tpy, 12 mo. 4400 hours/yr	EED, GCP
IA-0105	Iowa Fertilizer, Iowa	10/26/12	NG, 472	CO_2: 117 lb/mmBtu, 30-day N_2O: 0.0023 lb/mmBtu, 3-tests CH_4: 0.0006 lb/mmBtu, 3-tests CO_2e: 51,748 tpy, 12 mo.	GCP
TX-0629	BASF Total Petro-chemicals, Texas	8/24/12	NG, FG, 425.4	CO_2: 420,095 tpy, 12 mo.	GCP
T147-30464-00060	Indiana Gasification, Indiana	6/27/12	NG, 408 (2 ea.)	Thermal Efficiency: 81%, HHV basis CO_2: 88,167 tons/mmcf 3-hr avg	NG, EED
FL-0330	Port Dolphin Energy, Florida	12/01/11	NG, 278, 4 ea.	CO_2: 117 lb/mmBtu, 8-hr rolling avg	Tuning, optimization, controls, insulation, turbulent flow
LA-0254	Entergy Louisiana	8/6/11	NG, 338	CO_2: 117 lb/mmBtu CH_4: 0.0022 lb/mmBtu N_2O: 0.0002 lb/mmBtu	GCP

[1]Key:
NG = Natural gas fuel
EED = Energy Efficient Design
GCP = Good Combustion Practices
FG = Fuel Gas generated onsite

4.1.2 Boiler CO BACT

The boiler will emit CO as a product of incomplete combustion.

Proposal

Phillips proposed the following as BACT:

1. Proper design and good combustion practices;

2. CO emissions not to exceed 0.02 lb/mmBtu, 30-day average, rolled daily.

In addition to the use of good combustion practices, the Illinois EPA is also proposing that BACT for CO for the boiler be a limit of 0.02 lb/mmBtu, 30-day average, rolled daily.

Step 1: Identify Available Control Technologies

1. Oxidation Catalyst; and

2. Good Combustion Practices.

Step 2: Eliminate Technically Infeasible Options

1. An oxidation catalyst converts CO in flue gas to CO_2 with a catalyst, most often using a precious metal. These catalysts can become fouled or deactivated by sulfur compounds present in RFG. Oxidation catalyst CO control technology systems typically operate between 500°F and 700°F and may result in conversion of VOC and hydrocarbons along with CO to CO_2e. Use of an oxidation catalyst is a technically feasible control option for the boiler.

2. Good combustion practices to improve combustion efficiency and reduce CO emissions include:

   - Modern boiler and burner design and instrumentation to optimize fuel/air mixture, and combustion temperature.

   - Because CO is a product of incomplete combustion, these boiler and burner design measures for good (efficient) fuel combustion also reduce CO emissions; and

   - Careful boiler operation for good combustion and lower CO emissions. While the boiler and burner design are important for complete combustion, proper operation of the boiler is also needed for good combustion.

Good combustion practices are feasible for the boiler.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Good combustion design and operating practices would enable a CO emission rate of 0.02 lb/mmBtu to be achieved.

An oxidation catalyst has the capability to reduce CO emissions by up to an additional 80 percent to achieve an emission rate of 0.004 lb/mmBtu. An oxidation catalyst in conjunction with good combustion design and operating practices is therefore ranked higher than using good combustion design and operating practices, alone.

Step 4: Evaluate Most Effective Control Options

Phillips' permit application included a cost analysis for the use of an oxidation catalyst on the proposed boiler for CO control based on the general procedures outlined in USEPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual and Control Equipment Costing Spreadsheets.[36,37] The most substantial costs associated with an oxidation catalyst system are equipment capital cost and the costs to purchase initial and replacement catalyst. The catalyst is expected to last about 7 years before replacement is necessary to maintain the required emission rate.[38]

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[36] USEPA, OAQPS Control Cost Manual, 6th Edition, EPA 450/3-90-006, July 2002.
[37] USEPA, Control Equipment Costing Spreadsheets based on the OAQPS Control Cost Manual, July 1999.

[38] Seven years is a conservative catalyst life expectancy. Performance warranties are 3-5 years for some CO catalysts.

The results of the cost analysis indicate use of an oxidation catalyst on the new boiler would cost at least $11,500 (in 2013 dollars) per ton of CO removed.[39] Illinois EPA considers this cost to be excessive for CO control from the proposed boiler. In addition, use of an oxidation catalyst may require supplemental fuel, resulting in an increase in NOx emissions.

Step 5: Select BACT

Previous BACT determinations for CO for gas-fired boilers are listed in Table 4.1.2. These determinations confirm that good combustion practice is typically considered to be BACT for CO.

Only the CF Industries and Iowa Fertilizer permits include a lower emission rate (0.0013 lb CO/mmBtu) than that proposed by Phillips (0.02 lb CO/mmBtu) for the new boiler. The CF Industries boiler includes oxidation catalyst control while the Iowa Fertilizer boiler does not require catalytic control. It is important to note that the performance verification required by these permits is an initial 3-hour stack test and not continuous emission monitoring. Both boilers are still under construction and have not yet completed emission testing. Equipment performance is optimum at startup such that it may be possible to meet the required emission limit without oxidation catalyst. However, combustion efficiency tends to decline over time due to burner and heat transfer surface fouling or combustion chamber leaks that allow uncombusted gas to bypass to the exhaust stack. A CO CEMS, as is proposed in the CORE Permit Revision, will allow any inefficient boiler operation to be quickly identified and corrected.

The cost analysis provided by Phillips indicates the cost impact of an oxidation catalyst for the proposed boiler is excessive. Phillips' proposed BACT limits are consistent with the majority of the determinations and includes a CO CEMS to monitor CO emissions over the lifetime of the boiler.

Illinois EPA proposes a CO limit of 0.02 lb/mmBtu, 30-day average, rolled daily with good combustion design and operating practices. A limit of 0.02 lb/mmBtu will be achievable with modern automated boiler operating systems while still accommodating efficient boiler operation. CO emissions from the new boiler are required to be no more than 0.02 lb/mmBtu when averaged over 30-days, including startup, shutdown, and malfunction (SSM) periods when emissions may be higher than usual. This limit is at least as stringent as the limit for boilers without an oxidation catalyst found in the RBLC.

Table 4.1.2
Previous BACT Determinations for CO from Gas-Fired Boilers

ID	Facility	Date	Process Description	Throughput	Control Method	Basis
IN-0180	Midwest Fertilizer	6/4/14	Natural Gas Boilers (3)	218.6 mmBtu/hr	Good Combustion Practices, 37.22 lb/mmcf, 3-hr	BACT-PSD

[39] This estimate is based on vendor equipment estimates, reducing CO emissions by 80% from a baseline of 0.02 lb/mmBtu, and the cost estimation methodology in the USEPA Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual (CCM). See Tables E-2a and 2-c of the application for details.

ID	Facility	Date	Process Description	Throughput	Control Method	Basis
					avg.	
TX-0657	Beaumont Gas to Gasoline Plant	5/16/14	Natural Gas Boiler	950 mmBtu/hr	Good Combustion Practices, 50 PPM annual avg. and 96.44 tpy annual avg.	BACT-PSD
WY-0074	Solvay Chemicals	11/18/13	Natural Gas Fired Boiler	254 mmBtu/hr	Good Combustion Practices,0.037 lb/mmBtu 30-day avg.	BACT-PSD
NE-0054	Cargill, Incorporated	10/17/13	Natural Gas Boiler K	300 mmBtu/hr	Good Combustion Practices, 0.08 lb/mmBtu 1-hr avg	BACT-PSD
IN-0179	Ohio Valley Resources	9/25/13	Natural Gas Fired Boilers (4)	218 mmBtu/hr	Good Combustion Practices, 37.22 lb/mmcf, 3-hr average	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	7/12/13	Natural Gas Boiler	456 mmBtu/hr	Oxidation Catalyst, 0.0013 lb/mmBtu avg. of 3 stack test runs and 2.6 tpy rolling 12-month total	BACT-PSD
LA-0272	Dyno Nobel Louisiana Ammonia, LLC	3/27/13	Natural Gas Fired Boilers	217.5 mmBtu/hr	Good Combustion Practices, 10.87 lb/hr, 19.93 tpy	BACT-PSD
VA-0320	Celanese Acetate LLC	12/6/12	Natural Gas Fired Boilers (6)	400 mmBtu/hr	Good Combustion Practices, 50 PPMVD @3% O2 rolling 24-hr avg. including SSM	BACT-PSD
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Natural Gas Boiler	472.4 mmBtu/hr	Good Combustion Practices, 0.0013 lb/mmBtu avg. of 3 stack test runs and 0.57 tpy rolling 12-month total	BACT-PSD
IN-0166	Indiana Gasification, LLC	6/27/12	Two Aux Boilers	408 mmBtu/hr each	Good Combustion Practices, 0.036 lb/mmBtu 3-hr avg.	BACT-PSD
FL-0330	Port Dolphin Energy LLC	12/1/11	Boilers (4)	278 mmBtu/hr each	Good Combustion Practices, 0.015 lb/mmBtu except during SSM	BACT-PSD
TX-0597	Borger Refinery	12/11/09	Boiler	462.3 MMmmBtu/hr	Good Combustion Practices, 56.6 ppmvd CO	BACT-PSD
LA-0213	St. Charles Refinery	11/17/09	Three Boilers	715, 525, 354 MMmmBtu/hr	Good Operating Practices, 0.08 lb/mmbBtu	BACT-PSD
OH-0308	Sun Company, Inc., Toledo Refinery	2/23/09	Boiler (2)	374 mmBtu/hr each	Good Combustion Practices, 28 lb/hr, 122.64 tpy	BACT-PSD

ID	Facility	Date	Process Description	Throughput	Control Method	Basis
OH-0317	Ohio River Clean Fuels, LLC	11/20/08	Boiler	1200 MMmmBtu/hr	Catalytic Oxidation Device and Good Combustion Practices, 0.034 lb/mmBbtu 3-hr avg.	BACT-PSD
WA-0343	BP Cherry Point Refinery	11/17/07	Utility and Large Industrial Size Boilers/Furnaces	363 mmMMBtu/hr	Good Combustion Practices Using Modern Boiler and Burner Designs to Optimize Residence Time, Fuel/Air Mixing, and Combustion Temperature, Along with Careful Boiler Operation to Minimize CO Emissions	BACT-PSD
PA-0253	ConocoPhillips Trainer Refinery	2/6/07	Two Boilers	349,600 scf/hr	CO Catalyst, 30 tpy 12-mo rolling avg.	BACT-PSD
LA-0211	Garyville Refinery	12/27/06	Boiler No. 1	525.7 MMmmBtu/hr	Proper Design, Operation, and Good Engineering Practices, 0.04, 30-day avg	BACT-PSD
TX-0490	ConocoPhillips Borger Refinery	12/20/06	Unit 40 Boiler	598 MMmmBtu/hr	100 ppm 3-hr avg.	BACT-PSD
MS-0084	Chevron Products Co, Pascagoula Refinery	10/20/06	Boiler	265 MMBtummBtu/hr	Good air pollution control practices, 100 ppmv 3-hr avg. (0.072 lb/mmbBtu)	BACT-PSD
CA App# 12680	Genentech, Inc.	9/27/05	Natural Gas Boiler	97 MMmmBtu/hr	Pollution Prevention, 50 PPMVD @3% O2 three 30 min. sample periods	BACT-PSD
TX-0479	DOW Texas Operations Freeport	12/2/04	Combustion via Four Gas-Fired Steam Boilers	410 mmMMBtu/hr	Good Combustion Practices, 27.89 lb/hr and 488.6 tpy CO	BACT-PSD

ID	Facility	Date	Process Description	Throughput	Control Method	Basis
TX-0376	DOW Texas Operations Freeport	11/26/02	Six Boilers	382 and 457 mmMMBtu/hr	Good Combustion Practices, 0.073 lb/mmbBtu	BACT-PSD
LA-0200	Lake Charles Refinery	9/20/02	Two boilers	418 mmMMBtu/hr and 268 MMmmBtu/hr	Good Design, Using Gaseous Fuels for Good Mixing, and Proper Operating Techniques, 0.02 lb/mmbBtu	BACT-PSD

4.2 Hydrogen Plant 2 Vents GHG BACT

The Hydrogen Plant (HP-2) constructed as part of the initial CORE Project uses “closed technology” that eliminates continuous venting that was often present with older technology. Because of the use of “closed technology,” during the original CORE design, engineers assumed there would never be vent emissions from HP-2. However, Phillips has since determined that closed technology does not eliminate all venting. There are some operating scenarios that require blowdown and High Pressure Stripper (HPS) venting to maintain safe and/or stable operation during startup, shutdown, and malfunction. These vents contain steam and small quantities of CH_4, VOM, and ammonia. Phillips has included these previously unrecognized vent emissions in the permit revision application. Potential GHG emissions from these vents, 315 tpy CO_2e, are minimal.

Proposal

Phillips proposed a Hydrogen Plant design that eliminates continuous venting and maintenance and operating practices that minimize venting to the atmosphere as BACT for GHG emissions from the Hydrogen Plant blowdown and HPS vents.

The Illinois EPA is proposing that the BACT technology for GHG emissions for Hydrogen Plant 2 blowdown and HPS vents be a combination of design and operational practices that minimize venting.

Step 1: Identify Available Control Technologies

The available control technologies for GHG emissions that have been identified for Hydrogen Plant 2 vent emissions are:

1. Design technologies that eliminate continuous venting;

2. Operating and maintenance practices that minimize venting; and

3. CCS.

Step 2: Eliminate Technically Infeasible Options

1. Design Technology

Older hydrogen production technologies include continuous venting. Newer designs limit the need to open these heat recovery systems to the atmosphere to those periods when the system is in startup, shutdown, or malfunction operation. The WRR Hydrogen Plant 2 is designed to recirculate the steam blowdown and HPS vents under normal operating conditions. As such, design technologies that eliminate continuous venting are feasible for the blowdown and HPS vents at Hydrogen Plant 2.

2. Operating and Maintenance Practices

Unit runtime can be extended by careful maintenance and operation. Minimizing startup, shutdown, and malfunction operating periods also reduces the need to open the blowdown and HPS vents. Good operating and maintenance practices include proper instrumentation and controls, operating procedures, and maintaining equipment per manufacturer specifications. Operating and maintenance practices that minimize venting are feasible for the blowdown and HPS vents at Hydrogen Plant 2.

3. CCS

As previously discussed for the boiler, CCS poses technical challenges, is not yet commercially viable, and is considered to be technically infeasible. In particular, the streams are very low flow from the Hydrogen Plant 2 vents and contain only dilute concentrations of CO_2. In addition, flow from the vents is intermittent, occurring only during startup, shutdown, or malfunction.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Given the only feasible control options, design, operating, and maintenance practices that minimize venting would be required a ranking of these technologies is not necessary.

Step 4: Evaluate the Most Effective Controls

Phillips will utilize design, operating and maintenance procedures to minimize Hydrogen Plant 2 venting, so no further evaluation of these technologies is needed.

Incidentally, even if CCS were feasible for this dilute and intermittent stream, CCS is not a cost effective CO_2 control option for the vents. The annuitized cost to capture and store vent emissions is over $25,000 per ton of CO_2.[40] This cost is deemed to be excessive to control the 315 tons/year of CO_2 from these vents.[41]

Step 5: Select BACT

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[40] Phillips used cost information for CCS from the President's Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010. Annualized CCS costs are based on a 30 year equipment life, 7% interest rate from the OAQPS CCM Sixth Edition, and 12% inflation rate based on the Consumer Price Index from June 2007 to June 2013. Annualized costs were calculated by multiplying the estimated capital cost by the Capital Recovery Factor. The Capital Recovery Factor is calculated as: $I*(1+I)^n/[(1+I)^n-1]$ where I is the annual interest rate and n is the economic life of the equipment. See the Cost Manual developed by USEPA's Office of Air Quality Planning and Standards Tables E-3a through E-3f of the CORE Permit Revision application for further details.

[41] An additional drawback to CCS technology is its large energy requirements for operation. For instance, CCS requires a great deal of energy relative to the small quantity of GHG emissions generated from the vents at Hydrogen Plant 2.

Previous BACT determinations for GHG from hydrogen plant vents were not available from the Clearinghouse. A few permit examples for entire hydrogen plants at refineries mention these vents but do not set BACT limits for GHG since emissions from these vents are very small compared with other hydrogen plant emission sources. (See Table 5.4 of the LAER Discussion in Attachment 5.)

Illinois EPA is proposing design, maintenance, and operating practices that minimize venting as BACT for GHG for the Hydrogen Plant 2 blowdown and HPS vents. Specific provisions setting BACT for the Hydrogen Plant 2 vents are not being established due to the small amount of GHG emitted from these operations.

4.3 Fugitive Components GHG BACT

The proposed CORE Permit Revision will involve the addition of process piping to the new and modified fractionation columns and RFG and natural gas piping to the new boiler that includes valves, flanges and other connectors with the potential to emit CH_4, a component of GHG.

Proposal

Phillips proposes an LDAR program consistent with CORE Permit Condition 4.3.5(a). as BACT for GHG emissions from new or modified components associated with natural gas and RFG piping to Boiler 19 that could leak and result in fugitive methane emissions. This LDAR program will meet the leak threshold requirements of the most stringent requirement that is applicable to the WRR (as identified in Table 4.5.1). CH_4 will be measured as VOC for the purposes of this LDAR program. Valves will be monitored monthly and connectors will be monitored annually. Additionally, WRR proposes to install low emission valves for the relevant new or modified components, as available.

The Illinois EPA is proposing LDAR and low emission valves as BACT for GHG emissions from fugitive components for the revised CORE permit.

Step 1: Identify Available Control Technologies

Emissions of CH_4 from equipment components may be controlled with the following available technologies:

1. Application of LDAR program for leaks from piping and equipment in services that could emit CH_4; and

2. Installation low emission valves and dual pump seals for piping and pumps in services that could emit CH_4.

Step 2: Eliminate Technically Infeasible Options

1. LDAR

Several regulations that apply to portions of the facility already include LDAR requirements. These regulations include the Refinery MACT I (40 CFR 63 Subpart CC), the Hazardous Organics NESHAP (40 CFR 63 Subpart H), and 35 IAC 219 Subpart R for petroleum refineries. See Table 4.3.1 for a description of these various programs. RFG and process piping are already monitored for

VOM, so an extension of the current program to include natural gas components is feasible.

Table 4.3.1
Summary of Proposed LAER and Regulatory Leak Definitions

Component	Proposed LAER	Illinois EPA 35 IAC Part 219 Subpart R	MACT CC NSPS Option	MACT CC HON Option	NSPS GGG & VV	NSPS GGGa & VVa
Valves-Light Liquid	500	10,000	10,000	10,000	10,000	500
Valves-Heavy Liquid	No visual leaks	No visual leaks	No visual leaks	No visual leaks	No visual leaks	No visual leaks
Valves-Gas	500	10,000	500	500	10,000	10,000
Pumps-Light Liquid	2,000	10,000	10,000	10,000	10,000	2,000
Pumps-Heavy Liquid	No visual leaks	No visual leaks	No visual leaks	No visual leaks	No visual leaks	No visual leaks
Pressure Relief Valve-Gas	500	10,000	500	500	10,000	10,000
Pressure Relief Valve-Liquid	500	10,000	10,000	10,000	10,000	10,000
Light Liquid Connectors	500	No visual leaks	No visual leak	No visual leak	No visual leak	500
VOC Compressors	500	10,000	No visual leak	No visual leak	10,000	10,000
Closed Vent Systems	500	10,000	500	500	500	500

2. Low Emission Equipment Components

Low emission components, equipment designed to prevent leaks greater than 100 ppm for a period of at least five years, are generally considered to be technically feasible. Low emission equipment may not be available for all specialty piping components or piping services.

Both control options are feasible and could be implemented together to minimize CH_4 emissions from fugitive components.

Step 3: Ranking Remaining Control Options by Control Effectiveness

Because both technologies identified will be implemented as BACT, it is not necessary to rank the control options.

Step 4: Evaluate the Most Effective Controls

Since both control technologies will be required as BACT, further evaluation is not required.[42]

Step 5: Selection of BACT

A LDAR program and low emission piping components, if available, represent BACT for GHG from equipment components that handle streams that could leak CH_4 contained in natural gas, column overhead piping, and RFG. Previous BACT determinations for GHG emissions from fugitive components are listed in Table 4.3.2.

Table 4.3.2
Previous BACT Determinations for GHG from Fugitive Components

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
WY-0766	Simplot Phosphates, LLC	7/1/2014	Fugitives	Routine operation and maintenance of components	BACT-PSD
LA-0271	Crosstex Processing Services, LLC	5/24/2013	Fugitive Emissions	LDAR programs: NSPS OOOO, LAC 33:III.2111, and LAC 33:III.2122	BACT-PSD
LA-0266	Crosstex Processing Services, LLC	5/1/2013	Process Fugitives	LDAR programs: NSPS KKK and LAC 33:III.2121	BACT-PSD
LA-0263	Alliance Refinery	7/25/2012	Hydrogen Plant Fugitives	Implementation of the Louisiana refinery MACT leak detection and repair program; monitoring for total hydrocarbon content instead of VOC.	BACT-PSD
LA-0257	Sabine Pass LNG Terminal	12/6/2011	Fugitive Emissions	Conduct a LDAR program	BACT-PSD
TX-0612	Thomas C. Ferguson Power Plant	11/10/2011	Fugitive Natural Gas emissions	Comply with 40 CFR Part 98	Other Case-by-Case

[42] The proposed LDAR program leak threshold and monitoring frequency may be economically infeasible for monitoring methane, CH_4, leaks from natural gas piping for facilities that do not already have a stringent LDAR program in place.

Attachment 5

Discussion of Lowest Achievable Emission Rate (LAER) for New Emission Units Emitting VOM

Table of Contents

5.0 Introduction

The original CORE Project and the Terminal Expansion Project triggered NA NSR permitting requirements for VOM emissions since the WRR is located in a nonattainment area for 8-hour ozone and because the net increase in VOM emissions was determined to be significant. Therefore, the following VOM emission units impacted by the proposed CORE Permit Revisions will be evaluated for LAER:

- One new cooling water tower,
- Three new product storage tanks,
- One new boiler,
- Hydrogen Plant blowdown and HPS venting,
- Emergency relief venting, and
- Fugitive components (e.g., leaks from valves, flanges, etc.).

For major modifications in nonattainment areas, LAER is the most stringent emission limitation derived from either of the following[43]:

- The most stringent emissions limitation contained in the implementation plan of any State for such class or category of source; or

- The most stringent emission limitation achieved in practice by such class or category of source.

The most stringent emissions limitation contained in a SIP for a category of source must be considered LAER unless either a more stringent emissions limitation has been achieved in practice or the applicant is able to demonstrate that the SIP limitation is not achievable in this case. In addition, LAER cannot be less stringent than any applicable NSPS requirement.

5.1 Cooling Water Tower VOM LAER

A new cooling water tower would be added in the proposed CORE Permit Revision. A cooling water tower is a structure that includes a collection basin and plates open to the air over which water flows to reject heat by evaporation. Pumps and piping are used to circulate the water through heat exchangers to cool process streams before returning to the cooling water tower. Cooling water towers are primarily sources of particulate matter emissions due to drift loss and solids that are dissolved in the water droplets. Cooling water towers at refineries can also potentially emit very small quantities of VOM due to volatile materials in the water.

Proposal

Phillips proposed a combination of drift loss eliminators[44] and a comprehensive exchanger leak detection program as LAER for controlling VOM emissions from the new cooling water tower.

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[43] USEPA, Draft New Source Review Workshop Manual. Research Triangle Park, North Carolina. October, 1990.

[44] Drift eliminators contain packing which limit the amount of pollutants that become airborne during the cooling process. As mist passes through the packing, water and VOM are potentially captured and remain in the water rather than being emitted to the air.

A summary of the VOM control determinations identified in the RBLC is included in Table 5.1. Of the permits listed in the RBLC database that specify a method of VOM emissions control for cooling water towers, the most common is the use of drift loss eliminators and heat exchange system leak detection program monitoring. Drift loss eliminators and heat exchange system leak detection monitoring were also determined to be LAER for VOM in the original CORE Permit.

VOM emissions can occur from cooling towers used in refineries where the circulating water is used to cool down hydrocarbon process streams. Leaks in the process heat exchangers can occur. The VOMs that would consequently enter the cooling water would ultimately be stripped out by the cooling tower air flow. Therefore, a heat exchange system leak detection program and prompt repair are an effective VOM control. Illinois EPA is proposing high efficiency drift eliminators and a comprehensive exchanger leak detection program per 40 CFR 63 Subpart CC and 35 IAC Part 219 Subpart TT as LAER for controlling VOM emissions from the new cooling water tower.

Table 5.1
Previous LAER Determinations for VOM from Cooling Water Towers

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
TX-0657	Beaumont Gas to Gasoline Plant	5/16/2014	Cooling Tower	Monthly monitoring of VOC not to exceed 0.08 ppmw and 3.3 tpy annual emission limit	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC – Port Neal Nitrogen Complex	7/12/2013	Cooling Towers	Limit the amount of VOC in treatment chemicals and a drift eliminator	BACT-PSD
IA-0102	Davenport Works	2/01/2012	Cooling Towers	Facility is required to limit the amount of VOC in water treatment chemicals and the use of those chemicals. In addition the cooling towers have drift eliminators as control.	BACT-PSD
FL-0332	Highlands Biorefinery and Cogeneration Plant	9/23/2011	Cooling Towers (miscellaneous machinery)	Control VOC emissions by promptly repairing any leaking components in accordance with the approved LDAR plan. Collect a sample of cooling water on a weekly basis from miscellaneous machinery and process equipment cooling towers and analyze it for VOCs to enable the early detection of leaking heat exchangers and thereby minimizing VOC emissions from the cooling	OTHER CASE-BY-CASE

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
				towers. 0.001 VOC % by Water Flow Rate.	
LA-0246	St. Charles Refinery	12/31/2010	Four Cooling Towers	Monitoring VOC concentration in cooling water.	BACT-PSD
FL-0322	Sweet Sorghum-to-Ethanol Biorefinery	12/23/2010	Cooling Water Tower	Control VOC emissions by promptly repairing any leaking components in accordance with the approved LDAR plan. Collect a sample of cooling water on a weekly basis from cooling towers No. 1 and No. 3 and analyze it for VOCs to enable the early detection of leaking heat exchangers and thereby minimizing VOC emissions from the cooling towers.	BACT-PSD
TX-0575	Sabina Petrochemicals LLC	8/20/2010	Cooling Tower	Utilizes monthly monitoring of VOC in water or approved equivalent and identified leaks are repaired as soon as possible, but before next scheduled shutdown. 13.43 tpy annual VOM emission limit	BACT-PSD
LA-0213	St. Charles Refinery	11/17/2009	Five Cooling Towers	Monitoring process side of the heat exchangers for leaks	BACT-PSD
OH-0308	Sun Company, Inc., Toledo Refinery	2/23/2009	Cooling Tower, 2,000 gpm	Emission limits lb/hr and tpy and 0.7 lb/MM gallons flow	Other Case-by-Case
AL-0242	Tuscaloosa Refinery	5/20/2008	Cooling Tower	Adhere to the requirements of 40 CFR 63 Subpart CC	BACT-PSD
LA-0211	Garyville Refinery	12/27/2006	Three Cooling Towers	Monthly monitoring of the heat exchanger/cooling tower under LDAR program	BACT-PSD
IL-0102	Aventine Renewable Energy, Inc.	11/01/2005	Cooling Tower	Minimize VOM content of additives. 1.13 tpy VOM limit.	BACT-PSD
TX-0487	Rohm and Haas Chemicals LLC Lone Star Plant	3/24/2005	N-5 Cooling Tower North	0.45 lb/hr and 1.95 tpy VOM limits	BACT-PSD

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
TX-0487	Rohm and Haas Chemicals LLC Lone Star Plant	3/24/2005	N-5 Cooling Tower South	0.62 lb/hr and 2.72 tpy VOM limits	BACT-PSD
TX-0487	Rohm and Haas Chemicals LLC Lone Star Plant	3/24/2005	N-7 Cooling Tower	1.67 lb/hr and 7.33 tpy VOM emission limits	BACT-PSD
OK-0102	Ponca City Refinery	8/18/2004	FCCU Cooling Tower	Monitoring, inspection, and maintenance plan	BACT-PSD
OH-0276	Charter Steel	6/10/2004	Cooling Tower	0.15 lb/hr and 0.66 tpy VOM limits	BACT-PSD
TX-0459	Alcoa San Antonio Works	4/08/2004	Cooling Tower (4)	0.01 lb/hr and 0.01 tpy VOM limits	BACT-PSD
WI-0207	ACE Ethanol - Stanley	1/21/2004	Cooling Towers, F06	Mist eliminators with 0.15 lb/hr VOC from drift emission limit	BACT-PSD
OH-0256	Lima Chemicals Complex	7/10/2003	Cooling Tower	Drift eliminators and LDAR Program.	Other Case-by-Case
OK-0059	Ponca City Refinery	7/1/2002	Cooling Tower	Drift eliminators	BACT-PSD
TX-0235	Valero Refining Company - Corpus Christi Refinery	6/11/2002	Four Cooling Towers	Test water for VOC monthly with an approved air stripping system or equivalent. Repair leaking equipment at the earliest opportunity, but no later than the next scheduled shutdown of the process unit in which the leak occurs.	BACT-PSD

5.2 Storage Tank VOM LAER

Three new storage tanks will be added for the proposed CORE and Terminal Expansion Project Revisions, two at WRR and one at the Terminal. The tanks will store hydrocarbon with a maximum true vapor pressure of 11.1 psi.

Proposal

In the original CORE Permit, Lowest Achievable Emissions Rate (LAER) for storage tanks containing volatile organic material was determined to be a floating roof tank with primary liquid-mounted seal and secondary rim-mounted seal.

As part of the LAER determination for the CORE Permit Revision, additional guidance was discovered regarding tank seal technologies from the California South Coast Air Quality Management District (SCAQMD). SCAQMD Rule 463 categorizes various floating roof primary and secondary seal designs for organic liquid storage tanks. This guidance indicates that mechanical shoe seals are listed among those that "are deemed Best Available Control Technology," and are preferred over liquid-mounted foam logs and liquid-mounted toroid liquid filled logs for the control of VOM. SCAQMD's criteria for this categorization of floating roof tank seals are emission control effectiveness, ability to maintain contact with the tank wall, and longevity in service.

Based on this additional information, Phillips proposes LAER for VOM for the proposed new product tanks to be an internal floating roof with primary mechanical shoe seal and a secondary seal. Phillips also requested the permit be revised to clarify that installation of a mechanical shoe seal on the tanks already constructed under the original CORE permit will satisfy the LAER requirement.

Based on the review of the RBLC, NSPS Kb, MACT CC, and other regulatory agencies (e.g., the South Coast Air Quality Management District), an internal floating roof with primary mechanical shoe seal and secondary seals and the proper fittings are considered LAER for controlling VOM emissions from storage tanks. The proposed LAER is consistent with the control requirements of 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC. Recent determinations for petroleum storage tanks in naphtha/gasoline service are provided in Table 5.2.

Illinois EPA is proposing LAER for new refinery tanks TK-A033-1, TK-A037-1, and the terminal Tank 2003 to be fixed roof in combination with dual-seal internal floating roof design using mechanical shoe primary seals and rim-mounted secondary seals. Deck fittings will be gasketed or have a flexible fabric sleeve consistent with the requirements of NSPS Kb. Additionally, Section 4.4 of the CORE Permit and Section 4.2 of the Terminal Expansion Permit have been revised to clarify that installation of a mechanical shoe seal on the tanks already constructed as part of the original CORE and Terminal Expansion permits will satisfy LAER requirements for these tanks, based on the aforementioned SCAQMD guidance indicating this seal technology is preferred to foam-or liquid-filled primary seals. These controls meet the most stringent of the federal and state rules regulating petroleum liquid storage tanks installed at petroleum refineries.

Table 5.2
Previous BACT/LAER Determinations for VOM from Petroleum Storage Tanks

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
TX-0661	Oiltanking Houston, LP	6/30/2014	390, 210 and 127 Mbbl Storage Tanks	Domed External Floating Roof Tanks	LAER
TX-0657	Natgasoline LLC	5/16/2014	Gasoline Storage	Internal Floating Roof Tanks	BACT-PSD
TX-0653	Trafigura Terminals LLC	2/18/2014	Petroleum Liquid Storage	Floating roof tanks with welded decks, mech. shoe primary and rim-mounted secondary seals	BACT-PSD
TX-0637	KM Liquids Terminals LLC	10/15/2013	Petroleum Liquid Storage	Floating roof tanks with welded decks, mech. shoe primary and rim-mounted	LAER

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
				secondary seals	
WY-0071	Sinclair Refinery	10/15/2012	Storage Tank	External Floating Roof Tank	BACT-PSD
LA-0265	St. Charles Refinery	10/2/2012	FR Storage Tanks and EFR Storage Tank	Comply with MACT CC (Group 2) (FR Tanks), comply with NSPS Kb using EFR	BACT-PSD
TX-0613	East Houston Terminal	4/23/2012	Storage Tanks	Internal Floating Roof with Welded Seams, Mechanical Shoe Primary Seal and Rim Mounted Secondary Seal, lb/hr and tpy for normal operations and MSS requirements.	LAER
CA-1180	Chevron Products Co	8/24/2011	Recovered oil storage tank	Domed External Floating Roof Tank	Case-by-Case
OK-0139	Cushing Terminal Crude Oil Storage Facility	10/25/2010	External Floating Roof Tanks	External Floating Roof Tanks, tpy facility-wide VOM limit.	BACT-PSD
VA-0313	Transmontaigne Norfolk Terminal	4/22/2010	Storage Tank Losses	Floating roof and seal systems meeting NSPS Kb and MACT BBBBBB requirements (gasoline service)	Case-by-Case
LA-0228	Baton Rouge Junction Facility	11/2/2009	Five Gasoline Tanks	Internal Floating Roofs and Submerged Fill Pipes, tpy VOM limit.	BACT-PSD
TX-0537	LBC Houston LP	10/26/2009	Two New Storage Tanks	IFR configuration for routine emissions, flare or equiv. for refill and degas	Case-by-Case
WI-0251	Enbridge Energy	7/21/2009	T36-T40 Crude Oil Storage Tanks	External Floating Roof Tank, ton VOM/mo limit, 1 landing event per year, NSPS Kb. Controls on guidepoles, gasketed covers, and mechanical shoe seal primary with rim mounted secondary.	BACT-PSD
TX-0582	LBC Bulk Liquid Storage Terminal	7/1/2009	Storage and Transfer	Internal Floating Roof Tank, mech. shoe and rim-mounted seals, tank roof landing re-fill and degassing are controlled by flares	LAER
IL-0103	ConocoPhillips Wood River Refinery	8/5/2008	Crude Oil Storage Tanks (2)	Internal Floating Roof with Secondary Seal in Accordance with 40 CFR 60 Subpart Kb, and 40 CFR 63 Subpart CC.	LAER
NM-0050	Artesia Refinery	12/14/2007	Storage Tanks	External Floating Roof Tank Equipped with Double Seals, VP <=11.0 psi.	BACT-PSD

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
LA-0212	Zachary Station	2/1/2007	11.75 MM Gal and other Gasoline Tanks	Internal Floating Roof, lb/hr VOM limit on each tank.	BACT-PSD
LA-0211	Garyville Refinery	12/27/2006	Internal and External Floating Roof Storage Tanks	Internal and External Floating Roofs, comply with MACT CC	BACT-PSD
OK-0102	Ponca City Refinery	8/18/2004	Tank T-1101	Refinery MACT: Internal Floating Roof Tank with 2 Vapor Mounted Seals or a Mechanical Shoe	BACT-PSD
TX-0422	BP Texas City Chemical Plant B	12/5/2002	Tanks, Internal Floating Roof & Fixed Roof	Internal Floating Roof Installed in all tanks, Closure Devices, Tank Exteriors Painted White or Aluminum, Operation Without Visible Leaks and Spills, limits on individual tank lb/hr VOM limits on each tank.	BACT-PSD

5.3 Boiler VOM LAER

The proposed new natural gas and RFG-fired boiler, Boiler 19, will emit a small quantity of VOM as a result of incomplete combustion of fuel and is therefore subject to LAER.

Proposal

Phillips proposed maintaining and operating the new boiler with good combustion practices to reduce emission of VOM as LAER for the new boiler.

Illinois EPA is proposing a VOM limit of 0.004 lb/mmBtu, 30-day average, and good combustion practices, operation and maintenance as LAER for VOM emissions from the new boiler. USEPA has relied on good combustion practices as the technology to address emissions of organic hazardous air pollutants from boilers in 40 CFR 63 Subparts DDDDD and JJJJJJ, the NESHAP for boilers and certain other fuel combustion units. Good combustion practices for a boiler includes a modern, combustion management system to monitor and manage the level of oxygen in the flue gas and the flows of combustion air into the boiler.

Table 5.3
Previous LAER Determinations for VOM from Boilers

RBLC ID	Facility	Permit Date	Primary Fuel	Firing Rate	Control Method/Limit Description	Basis
AL-0271	Georgia Pacific LLC	6/11/2014	Natural Gas	425 mmBtu/hr	0.0053 lb/mmBtu	BACT-PSD
IN-0180	Midwest Fertilizer Corp	6/4/2014	Natural Gas	218.6 mmBtu/hr (3)	5.5 lb/mmcf, 3-hr avg.	BACT-PSD

RBLC ID	Facility	Permit Date	Primary Fuel	Firing Rate	Control Method/Limit Description	Basis
WY-0074	Solvay Chemicals, Green River Soda Ash Plant	11/18/2013	Natural Gas	254 mmBtu/hr	Good Combustion Practices, 0.0054 lb/mmBtu	Unknown
IN-0172	Ohio Valley Resources, LLC	9/25/2013	Natural Gas	218 mmBtu/hr (4)	Proper Design and Good Combustion Practices, 5.5 lb/mmcf, 3-hr avg.	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC	7/12/2013	Natural Gas	456 mmBtu/hr (2)	Good Operating Practices, 0.0014 lb/mmBtu	BACT-PSD
LA-0272	Dyno Nobel Louisiana Ammonia, LLC	3/27/2013	Natural Gas	217.5 mmBtu/hr (2)	Good Combustion Practices, 0.0054 lb/mmBtu	BACT-PSD
VA-0320	Celanese Acetate LLC		Natural Gas	400 mmBtu/hr	Good Combustion Practices, 2.2 lb/hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	10/26/2012	Natural Gas	472.4 mmBtu/hr	Good Combustion Practices, 0.0014 lb/mmBtu	BACT-PSD
FL-0330	Port Dolphin Energy LLC	12/1/2011	Natural Gas	278 mmBtu/hr	Good Combustion Practices, 0.0054 lb/mmBtu 3-hr avg.	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	8/16/2011	Natural Gas	338 mmBtu/hr	Use of Pipeline Quality Natural gas and Good Combustion Practices	BACT-PSD
LA-0246	St. Charles Refinery	12/31/2010	RFG	99 mmBtu/hr	Proper Design and Operation, Good Combustion Practices and Gaseous Fuels	BACT-PSD
MI-0389	Karn Weadock Generating Complex	12/29/2009	Natural Gas	220 mmBtu/hr	Efficient Combustion	BACT-PSD
LA-0213	St. Charles Refinery	11/17/2009	RFG	715 mmBtu/hr (3); 354 mmBtu/hr (2)	Proper Equipment Design and Operation, Good Combustion Practices, and Use of Gaseous Fuels	BACT-PSD
OH-0308	Sun Company, Inc., Toledo Refinery	2/23/2009	RFG	374 mmBtu/hr	The Boilers are the Control	

RBLC ID	Facility	Permit Date	Primary Fuel	Firing Rate	Control Method/Limit Description	Basis
AR-0094	John W. Turk Jr. Power Plant	11/5/2008	Natural Gas	555 mmBtu/hr	0.0055 lb/mmBtu 3-hr avg.	BACT-PSD
GA-0127	Plant McDonough Combined Cycle	1/7/2008	Natural Gas	200 mmBtu/hr	0.0051 lb/mmBtu, 3-hr avg.	LAER
ND-0024	Spriritwood Station	9/14/2007	Natural Gas	281 mmBtu/hr	Good Combustion Practices, 0.005 lb/mmBtu, 3-hr avg.	BACT-PSD
IA-0088	ADM Corn Processing - Cedar Rapids	6/29/2007	Natural Gas	292.5 mmBtu/hr	Good Combustion Practices, 0.0054 lb/mmBtu	BACT-PSD
PA-0257	Sunnyside Ethanol, LLC	5/7/2007	Natural Gas	76,000 scf/hr	Good Combustion Practices, 0.0054 lb/mmBtu	Other Case-by-Case
OK-0102	Ponca City Refinery	8/18/2004	RFG	No information in RBLC	Good Combustion Practices, 0.0054 lb/mmBtu	BACT-PSD

5.4 Hydrogen Plant 2 Vents VOM LAER

The Hydrogen Plant (HP-2) that was constructed as part of the original CORE Project uses a technology that eliminates continuous venting often present with older designs. Engineers originally assumed there would never be vent emissions from HP-2. However, Phillips has since determined there are some operating scenarios that require blowdown and High Pressure Stripper (HPS) venting to maintain safe and/or stable operation during startup, shutdown, and malfunction. Phillips has included these previously unrecognized vent emissions in the permit revision application. Emissions from these vents are negligible, 0.1 tpy VOM and 315 tpy of GHG, as CO_2e.

Proposal

Phillips proposed a hydrogen plant design that eliminates continuous venting and maintenance and operating practices that minimize venting as LAER for VOM emissions from the Hydrogen Plant 2 vents mentioned above. Because these vents are opened during startup, shutdown, or malfunction, extending unit runtime by careful maintenance and operation can reduce venting. Good operating and maintenance practices include proper instrumentation and controls, operating procedures, and maintaining equipment according to manufacturer specifications.

There are few BACT/LAER determinations for hydrogen plant vents available in the RBLC database. Neither are VOM emission limits or control requirements specific to hydrogen plant vents similar to those proposed in the revised permit addressed in any State Implementation Plans (SIPs).[45] Determinations for hydrogen plants at refineries are listed in Table 5.4. These determinations do not include limits or control requirements for hydrogen plant vents.

Illinois EPA is proposing design, maintenance, and operating practices that minimize venting as LAER for VOM emissions from Hydrogen Plant 2 blowdown and HPS vents. In addition, an emission limit of 0.1 tons/year, running 12-month total, has been established for these vents.

Table 5.4
Previous BACT/LAER Determinations for VOM from
Hydrogen Plant Vents

RBLC ID	Facility	Company	Permit Date	Process Description	Throughput	Control Method Description
AL-0242	Tuscaloosa Refinery	Hunt Refining Company	5/20/2008	No. 2 Hydrogen Plant Degasifier	No information in RBLC	No information in RBLC
LA-0211	Garyville Refinery	Marathon Petroleum	12/27/2006	Hydrogen Plant Steam Vent	254,500 lb/hr	No information in RBLC
LA-0211	Garyville Refinery	Marathon Petroleum	12/27/2006	Hydrogen Plant Deaerator Vent	3,125 lb/hr	No information in RBLC

5.5 Emergency Venting for New Fractionation Columns VOM LAER

The two new fractionation columns (V-3245 and V-3247) and other process equipment added or modified in the CORE Permit Revision will vent VOM in emergency pressure relief scenarios. Therefore, a LAER analysis is included for a worst-case emergency pressure relief scenario.

Proposal

Phillips proposes venting VOM emissions to the existing Distilling Flare equipped with flare gas recovery and operated using flare minimization practices as LAER for VOM emissions from emergency pressure relief venting.

The RBLC Clearinghouse and California Air Resources Board (CARB) database entries for VOM and other pollutant emissions emitted by emergency vents include incinerators, regenerative, recuperative, and catalytic thermal oxidation systems and carbon control. However, refinery and petrochemical fractionation column emergency venting is not amenable to these control technologies. Combustion in a flare is the refining industry standard for control of emergency pressure relief venting because a flare can control the sudden large gas releases and fluctuations in flow and VOC concentration that can occur during process upset more safely than other control options.

Carbon absorption technology is only used for low concentration, low flow gas streams. Emergency venting is just the opposite - high concentration and high flow. Therefore, carbon technologies are not appropriate control for emergency equipment venting.

[45] While these vents are subject to the Illinois' refinery waste gas stream requirements of 35 IAC 219.441, this is only because the hydrogen plant is co-located with the refinery. This rule limits emissions of organic material to a maximum of eight pounds per hour unless controlled to reduce the organic material concentration by 85 percent.

Thermal oxidation systems (regenerative, recuperative, or incinerators) must be sized for the maximum gas flow rate expected and must include a safety bypass for emergency situations. Since the only time the emergency vents require control is during an emergency, the use of a thermal oxidizer to combust emergency venting from the equipment added for the CORE Permit Revision is infeasible. Thermal oxidizers are best suited for controlling emissions from continuous vent streams while flares were designed as emergency safety devices to manage large intermittent vent streams such as the equipment emergency relief vents from the proposed CORE revisions.

Catalytic oxidation is not appropriate for treating emergency equipment venting because compounds in the flare exhaust gas such as sulfur can foul the catalyst, leading to decreased activity. The catalyst can be chemically washed to restore its effectiveness, but eventually irreversible degradation occurs and the catalytic oxidation CO control device on standby will not be capable of adequate treatment during a process upset. Like thermal oxidizers, catalytic oxidizers do not respond well to large fluctuations in inlet gas flow rate and composition. Based on the high sulfur concentrations, variable exhaust gas flow rates, and the variable nature of the composition of the emergency vent streams during upset conditions, oxidation catalyst is not technically appropriate.

Carbon absorption, thermal oxidation and catalytic oxidization are not appropriate controls for emergency venting and are therefore not alternatives for a flare in process emergency service.

Due to the VOM concentration and the variability in flow rate and composition of the emergency vent streams, control options other than the existing refinery flare are unsuitable. Boilers and heaters are in use onsite, but the anticipated flow rate and composition makes them unsuitable alternatives to the flare for reasons similar to those for the thermal oxidation technologies.

Illinois EPA is proposing venting of process emergency depressurization streams to the existing Distilling Flare as LAER for VOM. The existing flare which is provided with:

1. Flare Gas Recovery in a FGRS, and

2. Flare minimization practices developed and implemented by an Enhanced Flare Minimization Plan (FMP).[46]

These flare enhancements are consistent with the flare minimization requirements established in the 2006 BAAQMD flaring rules.[47] Given that the NSPS for flares does not require the installation and operation of a Flare Gas Recovery System (FGRS) and Enhanced FMP, the selected LAER is more

[46] The proposed 'Enhanced' FMP will include all elements of the NSPS Ja FMP, but the threshold for taking action following a flaring event is 100,000 scf/day compared to the Root Cause Analysis (RCA) threshold for the NSPS Ja FMP is 500,000 scf/day. An RCA is the prescribed investigation into the cause with actions to prevent recurrence following a flaring event over the listed threshold.

[47] BAAQMD Regulation 12 – Miscellaneous Standards of Performance, Rule 12 – Flares at Petroleum Refineries, Section 301 – Flare Minimization (Apr. 5, 2006).

stringent than the NSPS.[48] Because the Distilling Flare is an existing control device only being modified to add tie-ins for emergency flaring from the new distillation columns proposed for the CORE revision, and limits and work practices for the flare are covered in the facility CAAPP (95120306) and Consent Decree, December 5,, 2005, with addendums, additional requirements are not addressed in the CORE Permit Revision.[49] Also see the control methods listed in Table 5.5 below.

Table 5.5
Previous LAER Determinations for VOM from Flares

RBLC ID	Facility	Date	Process Description	Control Method	Basis
TX-0622	Equistar Chemicals, LP	10/24/2012	MSS Operations	Flaring of process equipment and vessels, including depressurizing and purging	BACT-PSD
TX-0574	Valero Three Rivers Refinery	8/19/2010	Flare MSS	Use best practices to recover fluids to process as much as possible before venting residuals to flare.	BACT-PSD
LA-0213	St. Charles Refinery	11/17/2009	Process Vents - Refinery (CCEX)	Route to the fuel gas systems or flares or comply with 40 CFR 63 Subpart CC	BACT-PSD
TX-0487	Rohm and Haas Chemicals LLC Lone Start Plant	3/24/2005	Safety Vent Stack (2)	None	BACT-PSD

5.6 Fugitive Component VOM LAER

The requested revisions to the CORE Permit will involve the addition of process piping that include pumps, valves, flanges and other connectors with the potential to emit VOM.

Proposal

Phillips proposed applying an LDAR program consistent with CORE Permit Condition 4.3.5(a) to new or modified components that could leak and result in fugitive VOM emissions. This LDAR program will meet the leak threshold requirements of the most stringent requirement that is applicable to the WRR (as identified in Table 5.6.1). Additionally, Phillips proposes to install

[48] Although the Distilling Flare will not be physically modified, piping tie-ins to a flare system are considered a flare modification according to the NSPS for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR Part 60 Subpart Ja. Therefore, the Distilling Flare will become subject to this NSPS.

[49] The reduction in emissions of VOM from routing emergency pressure relief events from the new fractionation columns to the Distilling Flare will be accompanied by an associated small emissions increase of CO, GHG, and other pollutants from combustion of these VOM emissions at the Distilling Flare. These small additional associated emissions increase are addressed by new emission limits established in the revised CORE Permit consistent with other units experiencing associated emissions changes as a result of the CORE Project. See Section 3.4.4 of the draft permit.

low emission valves[50] for the relevant new or modified components, where available in style, material of construction, and size suitable to process conditions.

The Illinois EPA is proposing LDAR and low emission valves as LAER for VOM emissions from fugitive components. The existing refinery LDAR program under the CORE Permit combined with low emission valves and dual sealed equipment is determined to meet LAER for equipment that could potentially leak VOM. Specifically, components added with the CORE Permit Revision will comply with the most stringent leak threshold requirements applicable to the WRR. The Terminal will use identical LAER control for fugitive components added with Tank 2003. Previous LAER determinations for VOM emissions from fugitive components are listed in Table 5.6.2.

Table 5.6.1
Summary of Proposed LAER and Regulatory Leak Definitions

Component	**Proposed LAER**	**Illinois EPA 35 IAC Part 219 Subpart R**	**MACT CC NSPS Option**	**MACT CC HON Option**	**NSPS GGG & VV**	**NSPS GGGa & VVa**
Valves-Light Liquid	500	10,000	10,000	10,000	10,000	500
Valves-Heavy Liquid	No visual leaks	No visual leaks	No visual leaks	No visual leaks	No visual leaks	No visual leaks
Valves-Gas	500	10,000	500	500	10,000	10,000
Pumps-Light Liquid	2,000	10,000	10,000	10,000	10,000	2,000
Pumps-Heavy Liquid	No visual leaks	No visual leaks	No visual leaks	No visual leaks	No visual leaks	No visual leaks
Pressure Relief Valve-Gas	500	10,000	500	500	10,000	10,000
Pressure Relief Valve-Liquid	500	10,000	10,000	10,000	10,000	10,000
Light Liquid Connectors	500	No visual leaks	No visual leak	No visual leak	No visual leak	500
VOC Compressors	500	10,000	No visual leak	No visual leak	10,000	10,000
Closed Vent Systems	500	10,000	500	500	500	500

Table 5.6.2
Previous LAER Determinations for VOM from Fugitive Components

[50] Low emission components are valves and other piping components designed to prevent leaks greater than 100 ppm for a period of at least five years. Low emission equipment may not be available for all specialty piping components or piping services.

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
TX-0613	East Houston Terminal	4/23/2012	Storage Tank Terminal Piping/ Components Fugitives	LAER LDAR Program. All Components Monitored Quarterly with 500 ppmv Leak Definition. Weekly Visual Check on Components in Heavy Liquid Service.	LAER
LA-0257	Sabine Pass LNG Terminal	12/6/2011	Fugitive Emissions	Mechanical seals or equivalent for pumps and compressors that serve VOC with vapor pressure of 1.5 psia and above	BACT-PSD
LA-0213	St. Charles Refinery	11/17/2009	Fugitive Emissions	Refinery (90-0): LA Refinery MACT LDAR Program;	BACT-PSD
LA-0228	Baton Rouge Junction Facility	11/2/2009	Fugitive Emissions	Conduct a Leak Detection and Repair Program as Specified by 40 CFR 63 Subpart R	BACT-PSD
LA-0197	Alliance Refinery	7/21/2009	Unit Fugitives	Leak Detection and Repair Program - Louisiana Refinery MACT Determination Dated JULY 26, 1994	BACT-PSD
LA-0225	Norco Refinery	3/25/2008	Diesel Hydrotreater, Catalytic Reformer, and Hydrocracker Unit Fugitive Emissions	40 CFR 60 Subpart GGG, 40 CFR 63 Subpart CC, Louisiana MACT Determination for Refinery Equipment Leaks July 26, 1994	BACT-PSD
NM-0050	Artesia Refinery	12/14/2007	Fugitive Equipment Components	MACT Subpart CC leak detection and repair program	BACT-PSD
CA-1145	Breitburn Energy - NewLove	6/5/2007	Oil and Gas: Fugitive Components	Low Emissions Design and Lower LDAR Threshold.	BACT-PSD
LA-0211	Garyville Refinery	12/27/2006	Fugitive Emissions	LDAR Program: Comply with Overall Most Stringent Program Applicable to Unit. Applicable Programs Include 40 CFR 63 Subpart CC, 40 CFR 60 Subpart GGG, LAC 33:III.2121, & LAC 33:III.CHAPTER 51 (LA Refinery MACT).	BACT-PSD
IL-0073	ExxonMobil Oil Corporation	8/19/2003	Fugitives	LAER is 40 CFR 63 Subpart H & leak definition of 500 ppm.	LAER
LA-0195	Lake Charles Facility	7/30/2003	Process Fugitives	LDAR Program - 40 CFR 63 Subpart I	BACT-PSD
TX-0422	BP Texas City Chemical Plant B	12/5/2002	Fugitives	Leak Inspection and Monitoring, Repair and Maintenance.	BACT-PSD

RBLC ID	Facility	Permit Date	Process Description	Control Method Description	Basis
OK-0059	Ponca City Refinery	7/1/2002	Fugitive Components/ Equipment Leaks	Refinery MACT Requires Inspection and Maintenance of Pump Seals, Valves, Flanges, and Pipes.	BACT-PSD

Attachment 6

Evaluation of Change in Emissions

As discussed in Section VI of the Project Summary, the increases in emissions considering the CORE Permit Revision are minor for NO_x, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2S and TRS; that is, emissions are below PSD and NA NSR thresholds. The emissions increases considering the CORE Permit Revision for VOM, CO, and GHGs are above PSD and NANSR thresholds, triggering major permitting requirements for changes proposed in the CORE Permit Revision that impact these pollutants, as described in Sections VI, VII, and VIII of this Project Summary. The table below compares the overall CORE Project (and Terminal Expansion Project) emissions before and after the revisions in these permits. Emissions of both VOM and CO are lower for the CORE Project as revised as compared to the original CORE Permit. GHGs were not subject to regulation at the time the original CORE permit application was submitted and were therefore, not quantified in the original permit. For further information refer to Attachments 1 and 2 of the draft revised permits and in the original CORE Permit and the Terminal Expansion Permit. These changes include both addition of new equipment and removal of equipment that will not be constructed and will no longer be addressed in the permits.

Summary of Emissions Changes for the CORE Project and the Terminal Expansion Project with the Proposed CORE Permit Revision and Proposed Terminal Permit Revision (Tons/Year)

	Parameter	**Original CORE Emissions Change**	**CORE Permit Revision Emissions Change**	**Difference between Original CORE and CORE Permit Revision (decreases shown as negative values)**
NANSR	**VOM**	379.4	328.1	-51.3
PSD	**CO**	1,010.8	855.8	-155.0
	GHGs (as CO_2e)[a]		216,300	

[a] The proposed CORE Permit Revision results in lower emissions of GHGs than from the original CORE Permit. In particular, the GHG emissions from FCCU-3, alone, would have been more than the GHG emission increases from the new boiler and other emission units.