IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF INDIANA
HAMMOND DIVISION

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| UNITED STATES OF AMERICA, and<br>THE STATE OF INDIANA,<br><br>Plaintiffs,<br><br>and<br><br>THE SIERRA CLUB, SAVE THE DUNES, THE NATURAL RESOURCES DEFENSE COUNCIL, THE HOOSIER ENVIRONMENTAL COUNCIL, SUSAN ELEUTERIO and TOM TSOURLIS,<br><br>Plaintiff-Intervenors<br><br>v.<br><br>BP PRODUCTS NORTH AMERICA INC.,<br><br>Defendant | ) | Civil No. 2:12 CV 207 |

CONSENT DECREE

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# CONSENT DECREE

WHEREAS, Plaintiff the United States of America ("United States"), by the authority of the Attorney General of the United States and through its undersigned counsel, acting at the request and on behalf of the United States Environmental Protection Agency ("EPA"), has simultaneously filed a Complaint and lodged this Consent Decree against defendant BP Products North America Inc., ("BPP" or "Defendant") for alleged environmental violations at its refinery located in Whiting, Indiana (the "Whiting Refinery");

WHEREAS, the State of Indiana ("Indiana") has joined in this matter alleging violations of its applicable State Implementation Plan provisions and/or other state rules, regulations, and permits incorporating and implementing the requirements of the Clean Air Act;

WHEREAS, the Sierra Club, Save the Dunes, the Natural Resources Defense Council, the Hoosier Environmental Council, the Environmental Integrity Project, the Environmental Law and Policy Center, Susan Eleuterio and Tom Tsourlis ("Citizen-Intervenors") by their execution of and entry into this Consent Decree are hereby seeking to intervene in this action, with the consent of the United States, Indiana and BPP, for the purpose of resolving claims they have made concerning the adequacy of certain permits issued to BPP by Indiana, and the entry of this Consent Decree shall constitute the granting of such intervention;

WHEREAS, the United States, Indiana and BPP are among the parties to a Consent Decree entered by this Court in Civ. No. 2:96 CV 095 RL on August 29, 2001 (the "2001 Consent Decree"), which has been amended several times between 2001 and 2009, and which covers the five refineries owned and operated by BP, including the Whiting Refinery;

WHEREAS, EPA has issued several Notices of Violation and Findings of Violations to BPP relating to the Whiting Refinery's compliance with various requirements of both the 2001 Consent Decree and the Clean Air Act;

WHEREAS, BPP is presently engaged in a capital improvement project, referred to by BPP as the Whiting Refinery Modernization Project ("WRMP"), that will modernize much of the Refinery and will enable BPP to substitute Canadian crude oil for a major portion of its existing crude slate;

WHEREAS on May 1, 2008, the Indiana Department of Environmental Management ("IDEM") issued a final Significant Source Modification permit authorizing BPP to proceed with the construction needed to implement the WRMP ("the WRMP Construction Permit");

WHEREAS, the terms and conditions of the WRMP Construction Permit were added to the Whiting Refinery's existing Title V operating permit (Operation Permit No. T089-6741-00453, hereinafter "the WRMP Operating Permit") on June 16, 2008;

WHEREAS, pursuant to these permits, BPP has been engaged in the construction activities necessary to implement the WRMP;

WHEREAS, on May 19, 2008, several of the Citizen-Intervenors jointly filed petitions for review with the Indiana Office of Environmental Adjudication ("OEA") challenging both the WRMP Construction Permit and the WRMP Operating Permit, which petitions for review are still pending before OEA in, Cause Nos. 08-A-J-4115 and 08-A-J-4142;

WHEREAS, on August 19, 2008, the Environmental Law and Policy Center, Hoosier Environmental Council, Natural Resources Defense Council, Save the Dunes Council, Inc., Sierra Club, Inc., Susan Eleuterio and Tom Tsourlis ("Title V Petitioners") submitted a petition to EPA pursuant to Section 505(b)(2) of the Clean Air Act ("Title V Petition") requesting that EPA object to the Title V permit modification issued by IDEM on June 16, 2008;

WHEREAS, the Title V Petitioners alleged in their Title V Petition that the Title V permit did not comply with Clean Air Act requirements because, *inter alia*, BPP's permit application omitted emissions data necessary to determine applicable Clean Air Act requirements and to establish appropriate emission limits, that the calculation to determine appropriate NSR requirements was done incorrectly and that the permit did not include appropriate BACT or LAER limits for flares and other sources, among other items;

WHEREAS, on October 16, 2009, EPA issued an order ("EPA Order") granting in part and denying in part the Title V Petition;

WHEREAS, the EPA Order specified that the NSR emissions calculations and analyses for the Whiting Refinery did not appropriately address the following emissions: emissions from new and existing flaring devices resulting from start-up, shut-down and malfunction of refinery process units; emissions from vessel depressurization; emissions from increased coking and coke drum depressurization; and emissions of fugitive sulfur compounds. The EPA Order also granted the Title V Petition on the issue that IDEM had not provided a sufficient rationale and response to comment on the issue of sulfur content of the Canadian crude oil feedstock to be refined at the Whiting Refinery. The EPA Order also directed IDEM to re-evaluate the issues of concerns and, if necessary, modify BPP's permit;

WHEREAS, the injunctive relief required by Part V of this Consent Decree ("Affirmative Relief/Environmental Projects") covers the matters on which the EPA Order granted the Title V Petitioners' request to object to BPP's Title V permit;

WHEREAS, the Parties intend that, once the applicable requirements of Part V of this Consent Decree are incorporated into a revised Title V permit for the Whiting Refinery, and such permit is issued by IDEM, the matters raised by the EPA Order will be addressed;

WHEREAS, by entering into this Consent Decree, BPP is committed to undertake an extensive set of projects at the Whiting Refinery (i) to assure present and future compliance with the Clean Air Act, and regulations and permits issued thereunder and (ii) to substantially reduce emissions of pollutants from the Whiting Refinery;

WHEREAS, the design cycle time for the New Coker built as part of WRMP includes five hours for the Quench Water Fill Time (and this Consent Decree requires no less than a 45-minute Quench Water Soak Time);

WHEREAS, BPP intends to continue to operate the fenceline monitoring program described in Appendix E of this Consent Decree beyond the minimum term specified in Appendix E;

WHEREAS, in conjunction with the negotiation of this Consent Decree, BPP has applied to IDEM for a Significant Source Permit Modification that incorporates terms and conditions implementing various requirements of this Consent Decree and to add those terms and conditions into the Whiting Title V Permit;

WHEREAS, because this Consent Decree incorporates all remaining obligations and requirements of the 2001 Consent Decree and its amendments that pertain to the Whiting Refinery (in addition to resolution of the matters described above), simultaneously with the lodging of this Consent Decree, the United States, Indiana and BPP have lodged a Seventh Amendment to the 2001 Consent Decree that would terminate all obligations under the 2001 Consent Decree that apply to the Whiting Refinery and otherwise amend the 2001 Consent Decree as needed to reflect the termination of the provisions applicable to the Whiting Refinery;

WHEREAS, by entering into this Consent Decree, BPP is committed to proactively resolving environmental concerns related to its operations;

WHEREAS, discussions between the Parties have resulted in the settlement embodied in this Consent Decree;

WHEREAS, BPP has waived any applicable federal or state requirements of statutory notice of the alleged violations;

WHEREAS, notwithstanding the foregoing reservations, the Parties agree that: (a) settlement of the matters set forth in the Complaint is in the best interests of the Parties and the public; and (b) entry of the Consent Decree without litigation is the most appropriate means of resolving this matter; and

WHEREAS, the Parties recognize, and the Court by entering the Consent Decree finds, that the Consent Decree has been negotiated at arms length and in good faith and that the Consent Decree is fair, reasonable, and in the public interest;

NOW THEREFORE, with respect to the matters set forth in the Complaint, and in Part XV of the Consent Decree ("Effect of Settlement"), and before the taking of any testimony, without adjudication of any issue of fact or law, and upon the consent and agreement of the Parties to the Consent Decree, it is hereby ORDERED, ADJUDGED and DECREED as follows:

## I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action and over the Parties pursuant to 28 U.S.C. §§ 1331, 1345, and 1355. In addition, this Court has jurisdiction over the subject matter of this action pursuant to Sections 113(b) and 167 of

the CAA, 42 U.S.C. §§ 7413(b) and 7477. The United States' Complaint states a claim upon which relief may be granted for injunctive relief and civil penalties against BPP under the Clean Air Act. Authority to bring this suit is vested in the United States Department of Justice by 28 U.S.C. §§ 516 and 519 and Section 305 of the CAA, 42 U.S.C. § 7605.

2. Venue is proper in the Northern District of Indiana pursuant to Section 113(b) of the CAA, 42 U.S.C. § 7413(b), and 28 U.S.C. §§ 1391(b) and (c) and 1395(a). BPP consents to the personal jurisdiction of this Court, waives any objections to venue in this District, and does not object to the participation of the State of Indiana in this action.

3. Notice of the commencement of this action has been given to the State of Indiana in accordance with Section 113(a)(1) of the CAA, 42 U.S.C. § 7413(a)(1), and as required by Section 113(b) of the CAA, 42 U.S.C. § 7413(b).

## II. APPLICABILITY AND BINDING EFFECT

4. The provisions of this Consent Decree shall apply to the Whiting Refinery, and shall be binding upon the United States, the State of Indiana, the Sierra Club, Save the Dunes, the Natural Resources Defense Council, the Hoosier Environmental Council, the Environmental Integrity Project, the Environmental Law and Policy Center, Susan Eleuterio and Tom Tsourlis and BPP and their agents, successors, and assigns.

5. BPP agrees not to contest the validity of this Consent Decree in any subsequent proceeding to implement or enforce its terms. BPP further agrees that, in any action to enforce this Consent Decree, it shall not raise as a defense the failure by any of its officers, directors, employees, agents, or contractors to take any actions necessary to comply with the provisions of this Consent Decree.

6. Effective from the Date of Entry of this Consent Decree until termination pursuant to Part XVII, BPP agrees that the Whiting Refinery is covered by this Consent Decree. Effective from the Date of Entry of this Consent Decree, BPP shall give written notice of this Consent Decree to any successors in interest to the Whiting Refinery prior to the transfer of ownership or operation of any portion of the refinery and shall provide a copy of this Consent Decree to any successor in interest. BPP shall notify the United States and Indiana, in accordance with the notice provisions set forth in Paragraph 210

("Notice"), of any successor in interest at least 30 days prior to any such transfer.

7. BPP shall condition any transfer, in whole or in part, of ownership of, operation of, or other interest (exclusive of any non-controlling, non-operational shareholder or membership interest) in the Whiting Refinery upon the execution by the transferee of a modification to this Consent Decree, which makes the terms and conditions of this Consent Decree applicable to the transferee. In the event of such transfer, BPP shall notify the United States and the State of Indiana in accordance with the notice provisions in Paragraph 210 ("Notice"). By no earlier than 30 days after such notice, BPP may file a motion to modify this Consent Decree with the Court to make the terms and conditions of this Consent Decree applicable to the transferee. BPP shall be released from the obligations and liabilities of this Consent Decree unless the United States or the State of Indiana opposes the motion and the Court finds that the transferee does not have the financial and technical ability to assume the obligations and liabilities under this Consent Decree.

8. Except as provided in Paragraph 7, BPP shall be solely responsible for ensuring that performance of the work required under this Consent Decree is undertaken in accordance with the deadlines and requirements contained in this Consent Decree and any attachments hereto. BPP shall provide a copy of the applicable provisions of this Consent Decree (or a link to the information on the internet) to each consulting or contracting firm that is retained to perform work required under this Consent Decree upon execution of any contract relating to such work. Copies of the applicable portions of this Consent Decree (or a link to the information on the internet) do not need to be supplied to firms who are retained solely to supply materials or equipment to satisfy the requirements of this Consent Decree.

## III. OBJECTIVES

9. It is the purpose of the Parties to this Consent Decree to further the objectives of the Clean Air Act.

## IV. DEFINITIONS

10. Unless otherwise defined herein, terms used in this Consent Decree shall

have the meaning given to those terms in the Clean Air Act and the implementing regulations promulgated thereunder. The following terms used in this Consent Decree shall be defined, solely for purposes of this Consent Decree and the reports and documents submitted pursuant thereto, as follows:

A. "7-day rolling average" shall mean the average daily emission rate or concentration during the preceding 7 days. For purposes of clarity, the first day used in a 7-day rolling average compliance period is the first day on which the emission limit is effective, and the first complete 7-day average compliance period is 7 days later (*e.g.*, for a limit effective on January 1, the first day in the period is January 1 and the first complete 7-day period is January 1 through January 7).

B. "365-day rolling average" shall mean the average daily emission rate or concentration during the preceding 365 days. For purposes of clarity, the first day used in a 365-day rolling average compliance period is the first day on which the emission limit is effective, and the first complete 365-day average compliance period is 365 days later (*e.g.*, for a limit effective on January 1, the first day in the period is January 1 and the first complete 365-day period is January 1 through December 31).

C. "12-month rolling average" shall mean the sum of the average rate or concentration of the pollutant in question for the most recent complete calendar month and each of the previous 11 calendar months, divided by 12. A new 12-month rolling average shall be calculated for each new complete month. For purposes of clarity, the first month used in a 12-month rolling average compliance period is the first full calendar month in which the emission limit is effective, and the first complete 12-month rolling average compliance period is 12 calendar months later (*e.g.*, for a limit effective on December 31, the first month in the period is January and the first complete 12-month period is January through the following December).

D. "Calendar Quarter" shall mean any one of the three month periods ending on March 31st, June 30th, September 30th, and December 31st.

E. "CEMS" shall mean a continuous emissions monitoring system.

F. "CEMS Root Cause Failure Analysis" means a process of analysis and investigation to determine the primary cause(s) for CEMS downtime.

G. "Claus Offgas Treater" or "COT" shall mean a "reduction control system" as defined in 40 C.F.R 60.101a followed by an incinerator.

H. "CO" shall mean carbon monoxide.

I. "Coke Drum" shall mean a pressurized vessel where coke is formed. The New Coker has the following Coke Drums: CD-201, CD-202, CD-203, CD-204, CD-205, and CD-206.

J. "Coke Drum Overhead Pressure" or "Coke Drum OH Pressure" shall mean the difference between the absolute pressure inside a Coke Drum and atmospheric pressure, expressed as psig, as measured on the coke drum overhead vapor line, during the coke steaming and quenching operations prior to commencing Coke Drum Venting.

K. "Coke Drum Steam Vent" or "Steam Vent" shall mean the vent and associated valves and piping on a Coke Drum that is used to vent vapors to the atmosphere. "Coke Drum Steam Vents" do not include the opening at the top of the Coke Drum used to insert the coke cutting device or the opening at the base of the Coke Drum used to discharge coke. The New Coker Coke Drums have the following Coke Drum Steam Vents:

| Identification of Coke Drum | Identification of Coke Drum Steam Vents Valves |
|---|---|
| CD-201 | XZV38160A/B |
| CD-202 | XZV38260A/B |
| CD-203 | XZV38360A/B |
| CD-204 | XZV38460A/B |
| CD-205 | XZV38560A/B |
| CD-206 | XZV38660A/B |

L. "Coke Drum Venting" or "Venting" shall mean the period between the opening of both of the Coke Drum's Steam Vent Valves and visual verification of no significant steam exiting the steam vent to the atmosphere.

M. "Coke Pit" shall mean a walled area into which coke and Quench Water are discharged from the opening at the base of the Coke Drum after cooling and cutting.

N. "Consent Decree" or "Decree" shall mean this Consent Decree, including any and all appendices attached to this Consent Decree, and any amendments thereto.

O. "Continuously Operate" or "Continuous Operation" shall mean, with respect to SCR, that it shall be used at all times the associated unit is in operation, except as necessary for consistency with the manufacturer's specifications and good engineering and maintenance practices for such equipment and the unit.

P. "Date of Entry" shall mean the date on which this Consent Decree is entered by the United States District Court for the Northern District of Indiana.

Q. "Date of Lodging" shall mean the date this Consent Decree is lodged with the United States District Court for the Northern District of Indiana.

R. "Day" or "Days" shall mean a calendar day or days. "Working Day" shall mean a day other than a Saturday, Sunday, or Federal holiday. In computing any period of time under this Consent Decree, where the last day would fall on a Saturday, Sunday, or Federal holiday, the period shall run until the close of business on the next Working Day, except that when a compliance date is specified in this Consent Decree, compliance must be achieved on or before that date.

S. "Downtime" or "monitor downtime" shall mean the period of time during operation of the emission unit being monitored in which any of the required CEMS data are either not recorded or are invalid for any reason (*e.g.*, monitor malfunctions, data system failures, preventive maintenance, unknown causes, etc.), but shall not include downtime associated with routine CEMS zero and span checks and QA/QC activities required by this Consent Decree. CEMS data that meet the requirements of 40 C.F.R. § 60.13 shall be considered valid for purposes of determining downtime.

T. "EPA" or "U.S. EPA" shall mean the United States Environmental Protection Agency and any successor departments or agencies of the United States.

U. "ESP" shall mean electrostatic precipitator.

V. "Federal Financial Assistance Transaction" shall mean a grant, cooperative agreement, loan, federally-guaranteed loan or other mechanism for providing federal financial assistance. An "open" Federal Financial Assistance Transaction is one for which the performance period has not yet expired.

W. "FCCU" or "FCU" as used herein shall mean a fluidized catalytic cracking unit and its regenerator.

X. "Fuel gas" or "refinery fuel gas" shall have the meaning set out in 40 C.F.R. § 60.101a.

Y. "Fuel gas combustion device" shall have the meaning set out in 40 C.F.R. § 60.101a.

Z. "Fuel gas system" or "refinery fuel gas system" shall mean the piping and control system that gathers gaseous streams generated by the Whiting Refinery's operations (including any that are blended with other sources of gas), and that are used as fuel in refinery heaters, furnaces, boilers, incinerators, gas turbines, and any other fuel gas combustion devices.

AA. "Fuel Oil" shall mean any liquid fossil fuel with sulfur content of greater than 0.05% by weight.

BB. "IDEM" shall mean the Indiana Department of Environmental Management and any successor departments or agencies of the State of Indiana.

CC. "Low NOx Burner" or "LNB" shall mean a burner that is designed to achieve a NOx emission rate of less than or equal to 0.040 lb NOx/mmBTU (HHV) when firing natural gas at 3% stack oxygen at full design load without air preheat, even if upon installation actual emissions exceed 0.040 lb NOx/mmBTU (HHV).

DD. "Malfunction" shall mean, as specified in 40 C.F.R. § 60.2, "any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions."

EE. "New Coker" or "Whiting New Coker" shall mean the delayed coking unit at the Whiting Refinery identified as the "New #2 Coker" in the WRMP Operating Permit. The New Coker includes, but is not limited to, the Coke Drums, the Quench Water System, and the associated coke handling systems.

FF. "NOx" shall mean nitrogen oxides.

GG. "Paragraph" shall mean a portion of this Consent Decree identified by an Arabic numeral.

HH. "Part" shall mean a portion of this Consent Decree identified by a Roman numeral.

II. "Parties" shall mean the United States, the State of Indiana, Citizen-Intervenors and BPP.

JJ. "PM" shall mean particulate matter as measured by EPA Methods 5B or 5F as specified in 40 C.F.R. Part 60, Subpart Ja. "$PM_{10}$" shall mean all filterable and condensable particulate matter ten microns or less in diameter, as measured by EPA Methods 201A and 202. "$PM_{TOTAL}$" shall mean all filterable and condensable matter, regardless of size, as measured by EPA Methods 5 and 202.

KK. "PSIG" or "psig" shall mean pounds per square inch gauge, which is the difference between absolute pressure at the measurement point and atmospheric pressure.

LL. "Quench Water" shall mean the water, in liquid phase, used to cool coke after it is formed in a Coke Drum.

MM. "Quench Water Fill Time" shall mean the duration of time between (i) the commencement of the initial addition of Quench Water to a Coke Drum after discontinuing the steam sweep and (ii) the point at which the coke bed has been covered with water and the water addition rate drops below 100 gallons per minute.

NN. "Quench Water Soak Time" shall mean the duration of time from the end of the Quench Water Fill Time and the start of Quench Water draining.

OO. "Quench Water Make-Up" shall mean the water, in liquid phase, added to the Quench Water System to compensate for water loss.

PP. "Quench Water System" shall mean the system used to receive, manage, treat, or convey Quench Water commencing from the point of discharge from the coke drum drains continuing through the Coke Pit, maze (coke fines settling basin), clean water sump and Quench Water Tank to the Coke Drums.

QQ. "Quench Water Tank" shall mean any tank that holds Quench Water.

RR. "Section" shall mean a portion of this Consent Decree identified by a capital letter.

SS. "Selective Catalytic Reduction" or "SCR" shall mean an air pollution control device consisting of ammonia injection and a catalyst bed to selectively catalyze the reduction of NOx with ammonia to nitrogen and water.

TT. "$SO_2$" shall mean sulfur dioxide.

UU. "Startup," as specified in 40 C.F.R. § 60.2, shall mean the setting in operation of equipment for any purpose.

VV. "Shutdown," as specified in 40 C.F.R. § 60.2, shall mean the cessation of operation of equipment for any purpose.

WW. "Tier III Motor Vehicle Emission and Fuel Standards" shall mean the new standards that EPA intends to promulgate pursuant to Title II of the Clean Air Act (42 U.S.C. § 7521 et. seq.), including Clean Air Act sections 202(a) and 211(v), as described in the Unified Agenda of Federal Regulatory and Deregulatory Actions under Regulatory Identification Number (RIN) 2060-AQ86.

XX. "Total Quench Time" shall mean the sum of Quench Water Fill Time and Quench Water Soak Time.

YY. "Total sulfur" shall mean all sulfur containing compounds, measured in parts per million.

ZZ. "Whiting Refinery" shall mean the refinery owned and operated by BPP and located at 2815 Indianapolis Boulevard in Whiting, Indiana.

AAA. "Ultra-Low NOx Burners" or "ULNBs" shall mean those burners that are designed to achieve a NOx emission rate of less than or equal to 0.020 lb/mmBTU HHV when firing natural gas at 3% stack oxygen at full design load without air preheat, even if upon installation actual emissions exceed 0.020 lb/mmBTU HHV.

BBB. "United States" shall mean the United States of America, including the United States Department of Justice and the United States Environmental Protection Agency.

CCC. "2001 Consent Decree" shall mean the civil consent decree entered in *United States, et al. v. BP Exploration and Oil, et al.*, Civil No. 2:96 CV 095 RL (N.D. Ind.) on August 29, 2001 and as thereafter amended.

## V. AFFIRMATIVE RELIEF/ENVIRONMENTAL PROJECTS

### A. NOx Emissions Reductions from FCCUs

Summary: BPP shall reduce NOx emissions at the Whiting Refinery FCCUs. BPP is also required to incorporate the NOx emission limits into its operating permits and will demonstrate future compliance with the lower emission limits through the use of CEMS. CEMS required under this Section are to be operated and data recorded pursuant to applicable law.

11. NSPS Applicability to FCCUs. By no later than the Date of Entry, FCU 500 and FCU 600 at the Whiting Refinery shall each be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, and shall be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and Ja, for NOx applicable to FCCUs. Entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for the FCCUs shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

12. Interim and Final FCCU NOx Emission Limits.

a. Interim Limits. Beginning on the Date of Entry, BPP shall comply with the following NOx emission limits at the Whiting Refinery:

i. FCU 500: BPP shall continue to comply with a long-term FCCU emission limit of 40 ppmvd NOx @ 0% $O_2$ (365-day rolling average) and a short-term FCCU emission limit of 80 ppmvd NOx @ 0% $O_2$ (7-day rolling average).

ii. FCU 600: BPP shall continue to comply with a long-term FCCU emission limit of 20 ppmvd NOx @ 0% $O_2$ (365-day rolling average) and a short-term FCCU emission limit of 40 ppmvd NOx @ 0% $O_2$ (7-day rolling average).

b. Final Limits. By no later than 90 Days after the Date of Entry, BPP shall comply with the following NOx emission limits at the Whiting Refinery:

i. FCU 500: BPP shall comply with a long-term FCCU emission limit of 35 ppmvd NOx @ 0% $O_2$ (365-day rolling average) and a short-term FCCU emission limit of 80 ppmvd NOx @ 0% $O_2$ (7-day rolling average); and

ii. FCU 600: BPP shall comply with a long-term FCCU emission limit of 10 ppmvd NOx @ 0% $O_2$ (365-day rolling average) and a short-term FCCU emission limit of 40 ppmvd NOx @ 0% $O_2$ (7-day rolling average).

c. NOx emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the 7-day rolling average emission limit required by this Paragraph, provided that during such periods BPP implements good air pollution control practices as required by 40 C.F.R. § 60.11(d) to minimize NOx emissions. NOx emissions during periods of Startup, Shutdown, or Malfunction shall be used in determining compliance with the 365-day rolling average emission limit required by this Paragraph.

13. Demonstrating Compliance with FCCU NOx Emission Limits. By no later than the Date of Entry, BPP shall use NOx and $O_2$ CEMS to monitor performance of the Whiting Refinery FCCUs and to report compliance with the terms and conditions of this Consent Decree. CEMS will be used to demonstrate compliance with the NOx emission limits established pursuant to Paragraph 12. BPP shall make CEMS data available to EPA and IDEM (as applicable) upon request. BPP shall install, certify, calibrate, maintain, and operate all CEMS required by this Paragraph at the Whiting Refinery in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. BPP must also conduct Cylinder Gas Audits each Calendar Quarter during which a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") is not performed.

## B. $SO_2$ Emissions Reductions from FCCUs

Summary: BPP is required to limit $SO_2$ emissions at the Whiting Refinery FCCUs. BPP is also required to incorporate the lower $SO_2$ emission limits into its operating permits and will demonstrate future compliance with these limits through the use of CEMS. CEMS required under this Section are to be operated and data recorded pursuant to applicable law.

14. NSPS Applicability to FCCUs. By no later than the Date of Entry, FCU 500 and FCU 600 at the Whiting Refinery shall each be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and Ja. By no later than the Date of Entry, FCU 500 shall be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and Ja, for $SO_2$ applicable to FCCUs, and by no later than September 1, 2013, FCU 600 shall be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and Ja, for $SO_2$ applicable to FCCUs. Entry of this Consent Decree and

compliance with the relevant monitoring requirements of this Consent Decree for the FCCUs shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

15. Interim and Final FCCU $SO_2$ Emission Limits.

a. Interim Limits. Beginning on the Date of Entry, BPP shall comply with the following $SO_2$ emission limits at the Whiting Refinery:

i. FCU 500: BPP shall continue to comply with a FCCU emissions limit of 25 ppmvd $SO_2$ @ 0% $O_2$ (365-day rolling average) and 50 ppmvd $SO_2$ @ 0% $O_2$ (7-day rolling average).

ii. FCU 600: BPP shall continue to comply with a long-term FCCU emission limit of 50 ppmvd $SO_2$ @ 0% $O_2$ (365-day rolling average) and a short-term FCCU emission limit of 125 ppmvd $SO_2$ @ 0% $O_2$ (7-day rolling average).

b. Final Limits. BPP shall comply with the following $SO_2$ emission limits at the Whiting Refinery:

i. FCU 500: By no later than December 31, 2012, BPP shall comply with a FCCU emissions limit of 10 ppmvd $SO_2$ @ 0% $O_2$ (365-day rolling average) and 50 ppmvd $SO_2$ @ 0% $O_2$ (7-day rolling average).

ii. FCU 600: By no later than September 1, 2013, BPP shall comply with a FCCU emissions limit of 10 ppmvd $SO_2$ @ 0% $O_2$ (365-day rolling average) and 50 ppmvd $SO_2$ @ 0% $O_2$ (7-day rolling average).

c. $SO_2$ emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the 7-day rolling average emission limit required by this Paragraph, provided that during such periods BPP implements good air pollution control practices as required by 40 C.F.R. § 60.11(d) to minimize $SO_2$ emissions. $SO_2$ emissions during periods of Startup, Shutdown, or Malfunction shall be used in determining compliance with the 365-day rolling average emission limit required by this Paragraph.

16. Demonstrating Compliance with FCCU $SO_2$ Emission Limits. By no later than Date of Entry, BPP shall use an $SO_2$ and $O_2$ CEMS to monitor the performance of the Whiting Refinery FCCUs and to report compliance with the terms and conditions

of this Consent Decree. CEMS will be used to demonstrate compliance with the $SO_2$ emission limits established pursuant to Paragraph 15. BPP shall make CEMS data available to EPA and IDEM (as applicable) upon request. BPP shall install, certify, calibrate, maintain, and operate all CEMS required by this Paragraph at the Whiting Refinery in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B. BPP must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed.

## C. Particulate Matter Emissions Reductions from FCCUs

Summary: BPP is required to control and limit emissions of PM, $PM_{10}$ and $PM_{TOTAL}$ from the Whiting FCCUs as provided in this Section.

17. NSPS Applicability to FCCUs. By no later than the Date of Entry, FCU 500 and FCU 600 at the Whiting Refinery shall each be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, and shall be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and Ja, for PM applicable to FCCUs. Entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for the FCCUs shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

a. By no later than 180 Days after the Date of Entry, and on a semi-annual basis thereafter, BPP shall conduct a performance test on each of FCU 500 and FCU 600 pursuant to 40 C.F.R. §§ 60.8 and 60.104a. Upon demonstrating through at least four (4) semi-annual tests that the PM limit in 40 C.F.R. § 60.102a(b)(1) is not being exceeded, BPP may reduce the required testing frequency to an annual basis. BPP shall provide notice to EPA no later than 30 Days in advance of the performance testing to be conducted pursuant to this subparagraph, and shall provide the results of such testing upon request by EPA.

b. In addition to the performance testing required by this Paragraph, BPP may conduct testing to identify any parameters that may need to be maintained to assure compliance with the PM limits during testing. BPP shall provide EPA with notice no later than 30 Days in advance of testing to identify parameters pursuant to this subparagraph, and shall provide the results of such testing upon request by EPA.

18. Emission Limits for $PM_{10}$ and $PM_{TOTAL}$. By no later than December 31, 2013, BPP shall comply with the following $PM_{10}$ and $PM_{TOTAL}$ emission limits at the Whiting Refinery:

a. FCU 500:

i. BPP shall comply with an emissions limit of 0.9 pound of $PM_{10}$ per 1,000 pounds of coke burned, as determined by EPA Methods specified in Paragraph 21.a.ii.

ii. BPP shall comply with an emissions limit of 1.2 pounds of $PM_{TOTAL}$ per 1,000 pounds of coke burned, as determined by EPA Methods specified in Paragraph 21.a.ii.

b. FCU 600:

i. BPP shall comply with an emissions limit of 0.7 pounds of $PM_{10}$ per 1,000 pounds of coke burned, as determined by EPA Methods specified in Paragraph 21.a.ii.

ii. BPP shall comply with an emissions limit of 1.2 pounds of $PM_{TOTAL}$ per 1,000 pounds of coke burned, as determined by EPA Methods specified in Paragraph 21.a.ii.

19. Supplemental FCCU PM Monitoring Requirements. In addition to the monitoring requirements of this Consent Decree and NSPS Subparts A and Ja applicable to FCCUs, by no later than the Date of Entry, BPP shall monitor and record the daily values for the following operating parameters:

a. The feed rate, in barrels per day, for each FCCU;

b. The average rate, in pounds per hour, at which $SO_2$-reducing catalyst additive is added to each FCCU; and

c. The average amount of ammonia in pounds per hour injected into the FCU 500 ESP and the average amount of ammonia in pounds per hour that is separately injected into the FCU 600 vaporizer and the ESP.

20. Demonstrating Compliance with $PM_{10}$ and $PM_{TOTAL}$ Emission Limits.

a. Compliance with the $PM_{10}$ and $PM_{TOTAL}$ emission limits in Paragraphs 18.a.i-ii and 18.b.i-ii shall be based on the emission rate computed from the most recent performance test completed pursuant to Paragraph 21.a.

b. BPP shall maintain compliance with the PM operating limits established under 40 C.F.R. § 60.102a(c)(1) during its demonstration of compliance with the $PM_{10}$ and $PM_{TOTAL}$ emission limits in Paragraph 18.

c. For the purposes of this Paragraph, BPP may use Method 201A in lieu of Method 5 to determine $PM_{TOTAL}$ emissions, provided that BPP follows the procedures in Method 201A for the collection and analysis of PM greater than 10 microns.

21. FCCU Performance Testing.

a. Testing Protocols for $PM_{10}$ and $PM_{TOTAL}$ Emissions: By no later than 180 Days after the Date of Entry, BPP shall implement a performance testing protocol as provided in this Paragraph:

i. Testing Frequency: BPP shall conduct performance tests to measure emissions of $PM_{10}$ and $PM_{TOTAL}$ from FCU 500 and FCU 600 on at least a semi-annual basis, with each semi-annual performance test being no sooner than four (4) calendar months from the date of completion of the previous semi-annual test. This shall not preclude BPP from conducting additional performance tests which are more frequent.

(1) Upon demonstrating, through at least four (4) valid, consecutive semi-annual tests conducted after December 31, 2013 that (i) the $PM_{10}$ and $PM_{TOTAL}$ limits are not being exceeded, (ii) the average of all four valid semi-annual tests is not more than 80% of the $PM_{10}$ and $PM_{TOTAL}$ limits, and (iii) the average result from any valid semi-annual test is not greater than 90% of the $PM_{10}$ and $PM_{TOTAL}$ limits, BPP may reduce the frequency of performance testing to an annual basis.

(2) BPP may request EPA approval to reduce the frequency of such testing in other circumstances. EPA has sole discretion to approve or disapprove BPP's request, which shall not

be subject to Dispute Resolution. In the event that a subsequent annual test indicates an exceedance of a $PM_{10}$ or $PM_{TOTAL}$ limit, EPA may elect to reinstate the requirement for semi-annual testing. EPA's decision to reinstate semi-annual testing shall not be subject to Dispute Resolution.

ii. <u>Test Methods for $PM_{10}$ and $PM_{TOTAL}$ Emissions</u>: BPP shall measure $PM_{10}$ emissions using Methods 201A and 202. BPP may use Method 5 in lieu of Method 201A for purposes of demonstrating compliance with the $PM_{10}$ emission limit provided that BPP considers all PM measured by Method 5 as $PM_{10}$. BPP shall measure $PM_{TOTAL}$ emissions using Methods 5 and 202. BPP may use Method 201A in lieu of Method 5 for purposes of demonstrating compliance with the $PM_{TOTAL}$ emission limit provided that BPP also follows the procedures in Method 201A for the collection and analysis of PM greater than 10 microns in diameter.

iii. <u>Test Run Duration</u>: Each performance test shall be comprised of at least three (3) valid two-hour stack test runs. BPP shall discard any invalid test runs, such as those that are compromised because of sample contamination. If a test run is discarded, BPP shall replace it with an additional valid test run. BPP shall report the results of the discarded test runs and shall provide all information necessary to document why the test run was not valid.

iv. <u>Valid Performance Tests</u>: A $PM_{10}$ and $PM_{TOTAL}$ test shall not be considered a valid test, and BPP will not have met the requirement of this Paragraph to test, unless each of the following conditions is met for that test:

(1) The average coke burn rate for all runs used in determining compliance with the $PM_{10}$ and $PM_{TOTAL}$ emission limits must not be less than the actual average coke burn rate over the time period since the previous performance test;

(2) The average $SO_2$ concentration for all runs used in determining compliance with the $PM_{10}$ and $PM_{TOTAL}$ emission limits must not be greater than 10 ppmvd @ 0% $O_2$; and

(3) The average total ammonia injection rate for all runs used in determining compliance with the $PM_{10}$ and $PM_{TOTAL}$ emission limits must not be less than average total ammonia injection rate over the time period since the previous performance test.

(4) Throughout the performance test, BPP shall target the average ESP total primary power since the last stack test. The average ESP total primary power for all the runs used in determining compliance with the $PM_{10}$ and $PM_{TOTAL}$ emission limits must not be greater than 120% of the average ESP total primary power since the last stack test.

v. Additional Parametric Monitoring During the Tests: BPP shall monitor or calculate and record $SO_2$ concentration, NOx concentration, catalyst additive rates, ammonia addition prior to ESP, ammonia addition at the SCR, ammonia slip, the coke burn-off rate, regenerator overhead temperatures, and FCCU feed rate for each test run. BPP shall reduce this monitoring data to an average that matches the time period of each test run.

22. FCCU Consultation. By no later than 3 months after the Date of Entry, BPP shall retain an outside consultant to evaluate the ESPs for FCU 500 and 600. The outside consultant shall produce a report with recommendations on how to optimize the performance of each ESP to enable each FCU to meet the PM, $PM_{10}$ and $PM_{TOTAL}$ emission limits in Paragraphs 17 and 18. By no later than 9 months after the Date of Entry, BPP shall provide this report to EPA and Citizen-Intervenors. BPP shall inform EPA and Citizen-Intervenors of any action taken to optimize the ESPs based on this report.

## D. <u>CO Emissions Reductions from FCCUs</u>

Summary: BPP is required to operate the Whiting Refinery FCCUs in a manner that minimizes CO emissions while complying with the NOx limits as required in this Section.

23. NSPS Applicability to FCCUs. By no later than the Date of Entry, FCU 500 and FCU 600 at the Whiting Refinery shall each be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, and shall be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and Ja, for CO applicable to FCCUs. Entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for the FCCUs shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

24. FCU 500 CO Emissions Limits. By no later than Date of Entry, BPP shall limit CO emissions from FCU 500 to 500 ppmvd or less on a 1-hour block average basis corrected to 0% $O_2$.

25. FCU 600 CO Emissions Limits. By no later than Date of Entry, BPP shall limit CO emissions from FCU 600 to 500 ppmvd or less on a 1-hour block average basis corrected to 0% $O_2$.

26. CO emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the 1-hour 500 ppmvd emissions limit, provided that during such periods BPP implements good air pollution control practices to minimize CO emissions.

27. Demonstrating Compliance with FCCU CO Emission Limits. By no later than the Date of Entry, BPP shall use a CO CEMS to monitor the performance of each FCCU and to report compliance with the terms and conditions of this Consent Decree. CEMS will be used to demonstrate compliance with the CO emission limits established pursuant to this Section. BPP shall make CEMS data available to EPA and IDEM upon request. BPP shall install, certify, calibrate, maintain, and operate all CEMS at the Whiting Refinery required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. BPP

must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed.

## E. VOC Emissions Reductions from FCCUs

Summary: BPP is required to operate the Whiting Refinery FCCUs in a manner that minimizes VOC emissions as provided in this Section.

28. FCU 500 VOC Emissions Limits. By no later than December 31, 2013, BPP shall limit VOC emissions from FCU 500 to 3.3 pounds of VOC per 1000 barrels of fresh feed.

29. FCU 600 VOC Emissions Limits. By no later than December 31, 2013, BPP shall limit VOC emissions from FCU 600 to 3.3 pounds of VOC per 1000 barrels of fresh feed.

30. Demonstrating Compliance with FCCU VOC Emission Limits.

a. BPP shall calculate VOC emissions using the following equations:

$$E = \left( \frac{C \times Q \times MW \times 60}{V_m} \right) \times \left( \frac{1000}{F} \right)$$

$$C = C_{total} - C_{methane} - C_{ethane}$$

Where:

| | | |
|---|---|---|
| E | = | FCCU VOC Emissions in lb/1000 bbl feed |
| C | = | Concentration of non-methane and non-ethane organic carbon as carbon in volume fraction |
| $C_{total}$ | = | Concentration of total organic carbon in volume fraction, as carbon, as measured by EPA Method 25a |
| $C_{methane}$ | = | Concentration of methane in volume fraction, as carbon, as measured by EPA Method 18 |
| $C_{ethane}$ | = | Concentration of ethane in volume fraction, as carbon, as measured by EPA Method 18 |
| MW | = | Molecular weight of carbon = 12.01 lb/lb-mole |
| Q | = | FCCU stack flow in dry standard cubic feet per minute as measured by EPA Method (s) 1-4 |

| | | |
|---|---|---|
| 1000 | = | Conversion factor to put emissions on a per 1000 bbl feed |
| $V_m$ | = | 385.3 dscf of gas per lb-mol at standard conditions (68° F) |
| F | = | FCCU feed rate in bbl/hour, averaged over period of source test |
| 60 | = | conversion factor for 60 minutes per hour |

b. BPP shall conduct the first stack test at each FCCU no later than December 31, 2013, and shall thereafter conduct annual stack tests at each FCCU, except as provided in Subparagraph 30.c below.

c. After the first stack test has been conducted for each FCCU pursuant to this Consent Decree:

i. If a stack test for a FCCU demonstrates that VOC emissions from that FCCU are less than half of the applicable VOC emissions limit, BPP may thereafter elect to conduct stack tests at least once every three (3) years at that FCCU in lieu of annual stack testing.

ii. If, after BPP exercises the option to conduct stack testing at least once every three (3) years pursuant to this Paragraph, a stack test demonstrates an exceedance of the applicable VOC emissions limit for that FCCU, BPP shall resume annual stack testing for that FCCU.

## F. NOx Emissions Reductions from Heaters and Boilers

Summary: BPP is required to undertake measures to reduce emissions of NOx from the Heaters and Boilers at the Whiting Refinery, as provided in this Section.

31. Installation of Ultra Low-NOx Burners On Certain Heaters.

a. By no later than the Date of Lodging, BPP shall conduct NOx emission tests on heaters F-2 and F-3 in the 4UF process unit and heater H-1X in the 11A Pipestill process unit for purposes of determining the baseline emission rate of each of these three heaters prior to installation of the controls required by this Paragraph. These tests shall be conducted using 40 C.F.R. Part 60 Appendix

A, Method 7E in combination with either EPA Method 19, or EPA Methods 1, 2, 3, and 4, or an EPA-approved alternative test method.

b. BPP shall install Ultra-Low NOx Burners by no later than the dates specified in the table below, and shall maintain, continuously operate and comply with the applicable emission limit by no later than the dates set forth for each listed heater and boiler:

| Unit | Installation Date | Emission Limit (12-Month Rolling Average) | Compliance Date |
|---|---|---|---|
| 11A Pipestill H-1X | December 31, 2013 | 0.06 lb/mmBtu | December 31, 2013 |
| 4UF F-2 Furnace | December 31, 2016 | 0.04 lb/mmBtu | December 31, 2016 |
| 4UF F-3 Furnace | December 31, 2016 | 0.04 lb/mmBtu | December 31, 2016 |

32. By no later than the compliance dates specified in Paragraph 31.b., BPP shall install, operate, calibrate and maintain NOx CEMS on each heater identified in that Paragraph and shall use CEMS to demonstrate and report compliance with the NOx emission limits applicable to those heaters.

33. NSPS Subparts A & Ja Applicability to New and Modified Heaters and Boilers.

a. Upon the Date of Entry, each of the following heaters and boilers shall be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 C.F.R. Part 60, Subparts A and Ja for NOx emissions for process heaters by the date specified in Subpart Ja:

i. 12 Pipestill heaters (H-101A, H-101B and H-102).

ii. #2 Coker heaters (F-201, F-202 and F-203).

iii. GOHT heaters (F-901A, F-901B).

iv. BOU F-401 furnace.

b. By no later than December 31, 2013, 11C Pipestill heater H-200 shall be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of NSPS Subparts A and Ja for NOx emissions from process heaters.

c. Entry of this Consent Decree and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a) for each heater listed in this Paragraph.

34. Additional Requirements For New and Modified Heaters.

a. BPP shall comply with the emission limits and Continuously Operate the listed NOx control technology listed in the following table by no later than the date of initial startup of the relevant unit:

| Unit | Rated Capacity (mmBTU/hr) | Control Technology | Emission Limit |
|---|---|---|---|
| 11C Pipestill H-200 Heater | 249.5 | ULNB | 0.05 lbs/mmBtu |
| 12 Pipestill H-101A Heater | 355 | ULNB | 77.7 tpy |
| 12 Pipestill H-101B Heater | 355 | ULNB | 77.7 tpy |
| 12 Pipestill H-102 Heater | 331 | ULNB | 72.5 tpy |
| BOU F-401 Furnace | 35 | | 0.098 lbs/mmBtu |
| #2 Coker F-201 Heater | 208 | ULNB & SCR | 18.2 tpy |
| #2 Coker F-202 Heater | 208 | ULNB & SCR | 18.2 tpy |
| #2 Coker F-203 Heater | 208 | ULNB & SCR | 18.2 tpy |
| DHT B-601-A Heater | 42 | ULNB | 7.3 tpy |
| GOHT F-901A Heater | 47 | ULNB | 0.04 lbs/mmBtu |
| GOHT F-901B Heater | 47 | ULNB | 0.04 lbs/mmBtu |

b. The rated capacities listed in Paragraph 34.a are those as of the Date of Lodging and are included solely for purposes of identification of the relevant control technology and emission limit in Paragraph 34.a, and of the relevant monitoring requirement in Paragraph 35.

35. Monitoring and Testing. BPP shall monitor and test the following heaters at the Whiting Refinery as follows:

a. Affected Heaters with a Capacity Greater Than 100 mmBTU/hr. Once every five years, BPP shall conduct a NOx performance test for each of the following process heaters with a rated capacity greater than 100 mmBTU/hr that are not monitored by a NOx CEMS :

i. 4UF Furnaces F-4, F-5, and F-6 (venting through a common stack).

ii. 4UF Furnaces F-1, F-8A, and F-8B (venting through a common stack).

iii. ARU Furnace F-200A.

iv. ARU Furnace F-200B.

v. 11C Pipestill Heater H-300.

vi. HU Heater B-501.

vii. ISOM Heater H-1.

BPP shall comply with the performance test protocols established by EPA Method 7E in conjunction with either EPA Method 19 or EPA Methods 1, 2, 3 and 4, or an EPA-approved alternative test method.

b. New and Modified Heaters with a Capacity Greater Than 100 mmBTU/hr. BPP shall install or continue to operate a NOx CEMS on the heaters and boilers listed in Paragraph 34 with a maximum rated capacity greater than 100 mmBTU/hr (HHV) by no later than December 31, 2013 (for the 11C Pipestill H-200 Heater) or the date of initial startup of the heater (for all other heaters).

c. In the permit applications required by Paragraph 83.a, BPP shall apply to remove the authority that is currently contained in the existing permit to replace the existing burners in the ISOM Heater H-1 with larger burners.

36. CEMS Monitoring Requirements.

a. Performance Specifications. Beginning no later than one hundred and eighty (180) days after installing the applicable control technology on a heater or boiler that shall be monitored by use of a NOx CEMS required by Paragraph 34, BPP shall install, certify, calibrate, maintain, and operate these CEMS in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and 40 C.F.R. Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. Unless Appendix F requirements are specifically required by NSPS or state regulations, BPP must conduct either a RAA or a RATA on each CEMS at least once every three (3) years in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4. BPP shall conduct a Cylinder Gas Audit each Calendar Quarter during which a RAA or a RATA is not performed.

b. Calculations.

i. NOx emissions in lbs/mmBtu shall be calculated using 40 C.F.R. Part 60, Appendix A, Method 19 and either the 12-month rolling average NOx concentration as determined by CEMS (for units monitored by a CEMS) or the NOx concentration measured in the most recent stack test demonstrating compliance (for units not monitored by a CEMS).

ii. NOx emissions in tons/year shall be calculated using the following equation:

$$E_{tpy} = \text{lb/mmBtu NOx} * H * 1 \text{ ton/2000 lbs.}$$

Where:

| | | |
|---|---|---|
| $E_{tpy}$ | = | Stack NOx emissions in tons per year |
| H | = | Total heat input in mmBtu to the unit from fuels fired in the unit(s) over the previous rolling 12-month period |
| lb/mmBtu NOx | = | lb/mmbtu emissions rate determined in accordance with Paragraph 36.b.i. |

37. The requirements of this Section do not exempt the Whiting Refinery from complying with any and all Federal, state, regional, and local requirements that may mandate technology, equipment, monitoring, or other upgrades that are: (a) based on actions or activities occurring after the Date of Entry of this Consent Decree; or (b) based upon new or modified regulatory, statutory, or permit requirements after the Date of Lodging.

38. BPP shall retain all records required to support its reporting requirements under this Section of the Consent Decree until its termination pursuant to Part XVII (Termination). BPP shall make such records and all CEMS data and test results available to EPA and IDEM upon request.

## G. $SO_2$ Emissions Reductions from Heaters and Boilers

Summary: BPP is required by this Section to undertake measures to reduce $SO_2$ emissions from refinery heaters and boilers by restricting $H_2S$ in refinery fuel gas and not burning Fuel Oil, except as specifically permitted under the provisions set forth in this Section.

39. NSPS Applicability to Heaters and Boilers.

a. Subpart Ja Applicability to Certain Existing Heaters and Boilers. Upon the Date of Entry, each of the following heaters and boilers shall be an "affected facility" for $SO_2$ as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of NSPS Subparts A and Ja for $SO_2$ emissions for fuel gas combustion devices:

i. 11A Pipestill heaters (H-1X, H-2 and H-3).

ii. 11C Pipestill heaters (H-200 and H-300).

iii. New Hydrogen Unit heaters (HU-1 and HU-2).

iv. BOU F-401 furnace.

v. ISOM H-1 heater.

vi. HU B-501.

vii. CFHU heaters (F-801A, F-801B and F-801C)

viii. DDU heaters (WB-301 and WB-302).

ix. 4 UF heaters (F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A and F-8B).

x. ARU heaters (F200A and F-200B).

xi. 3SPS boilers (#1, #2, #3, #4 and #6).

xii. 3SPS Duct Burners.

xiii. CRU heaters (F-101 and F-102A).

b. Subpart Ja Applicability to Certain New Heaters and Boilers. Upon the date of initial start-up, each of the following heaters and boilers shall be an "affected facility" for $SO_2$ as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 C.F.R. Part 60, Subparts A and Ja for $SO_2$ emissions for fuel gas combustion devices:

i. 12 Pipestill heaters (H-101A, H-101B and H-102).

ii. #2 Coker heaters (F-201, F-202 and F-203).

iii. GOHT heaters (F-901A, F-901B.

iv. New Boiler 1.

c. Entry of this Consent Decree and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a) for the heaters listed in Paragraph 39.a.

40. Elimination of Fuel Oil Burning.

a. Existing Heaters and Boilers. Effective on the Date of Entry, BPP shall not burn Fuel Oil in any heater or boiler at the Whiting Refinery in existence as of the Date of Lodging.

b. Heaters or Boilers Constructed After Entry. After the Date of Entry, BPP shall not construct any new heater or boiler that burns Fuel Oil unless the air pollution control equipment controlling the combustion device either:

i. has an $SO_2$ control efficiency of 90% or greater; or

ii. achieves an $SO_2$ concentration of 20 ppm or less at 0% $O_2$ or less on a 3-hour rolling average basis, rolled hourly.

Nothing in this Paragraph shall exempt BPP from securing all necessary permits before constructing a new heater or boiler at the Whiting Refinery.

## H. Fuel Gas Sulfur Content

41. Limit on Total Sulfur Content in Refinery Fuel Gas. By no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in any heater, furnace or boiler at the Whiting Refinery shall not exceed 70 ppmvd total sulfur calculated as $H_2S$ on a 12-month rolling average basis.

42. Demonstrating Compliance with Total Sulfur Emission Limits.

a. By no later than December 31, 2013, BPP shall install three Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration in refinery fuel gas, and to report compliance with the terms and conditions of this Consent Decree. The Total Sulfur Continuous Analyzers will be used to demonstrate compliance with the fuel gas sulfur concentration limit established pursuant to Paragraph 41. Consistent with 40 C.F.R. § 60.107a(a)(2)(iv), BPP shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 C.F.R. § 60.107a(a)(3). The locations currently planned for these monitors are indicated in Appendix A. If BPP changes the location of any of these monitors, BPP shall notify EPA and submit a revised Appendix A showing the new locations in the next report required by Part VIII.

b. BPP shall begin reporting data from the total sulfur analyzers to EPA and the Citizen-Intervenors once the analyzers are placed into service and certified.

c. The Total Sulfur Continuous Analyzers required by this Paragraph shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 C.F.R. Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B, except that in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, BPP must conduct either a RAAor RATA on each Total Sulfur Continuous Analyzer at least once every three (3) years. BPP must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ASTM D3246-05 shall be used as the reference method. BPP shall make total sulfur analyzer data available to EPA and IDEM (as applicable) upon request.

## I. <u>CEMS Downtime Minimization, O&M and Corrective Action</u>

43. By no later than 180 days after the Date of Entry, BPP shall develop and submit for EPA review as provided in Paragraph 47 a comprehensive CEMS Operation and Maintenance Plan ("CEMS O&M Plan" or "Plan") for the Whiting Refinery that is designed to enhance the performance of CEMS components, improve CEMS accuracy and stability, and minimize periods of CEMS downtime. This CEMS O&M Plan shall include at a minimum each of the elements identified in Paragraphs 44 through 46.

44. <u>CEMS Operations and Maintenance Training</u>. The CEMS O&M Plan shall provide for regular training for all individuals (BPP employees and contractors) involved in CEMS operations and maintenance to maintain necessary levels of monitoring competency. All newly-hired individuals (BPP employees and contractors) involved in CEMS operations and maintenance shall be trained prior to undertaking any CEMS-related responsibilities. The CEMS O&M Plan shall additionally ensure that all individuals involved in CEMS operations and maintenance have access to and are familiar with the CEMS O&M Plan.

45. <u>CEMS Testing and Calibration</u>. BPP shall certify, calibrate, maintain, and operate all CEMS in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. These requirements shall be included in the CEMS O&M Plan.

46. <u>Preventative Maintenance and Repair, and Quality Assurance/Quality Control ("QA/QC")</u>. The Whiting Refinery's CEMS O&M Plan shall include the following:

a. A CEMS preventive maintenance program to provide for a regularly scheduled set of activities designed to prevent problems before they occur. Such activities and procedures may be based initially on the CEMS vendor's recommendations. Routine preventative maintenance procedures shall be updated periodically to include such procedures as may be necessary or appropriate based on experience with each CEMS.

b. A CEMS QA/QC program to include provisions for assessing and maintaining the quality of continuous emission monitoring data, including regular (*e.g.,* daily, weekly monthly) routine internal (and, as needed, external) maintenance and operation checks designed to maintain or improve data quality and minimize CEMS downtime. Internal checks include, but are not limited to, CEMS inspections, periodic calibrations, routine maintenance and measures to assess the quality of CEMS data (*i.e.,* accuracy and precision). External checks include, but are not limited to, independent third-party CEMS audits, third-party sampling and analysis for accuracy and precision, or other assessments to ensure continuous and accurate CEMS operations.

c. A CEMS repair program to ensure the timely repair of CEMS to address both routine maintenance and repair and non-routine maintenance and repair. BPP shall maintain a spare parts inventory adequate to meet the normal operating and CEMS preventative maintenance requirements. BPP shall establish procedures for acquisition of parts on an emergency basis (*e.g.,* vendor availability on a next-day basis). An individual at the Whiting Refinery shall be designated for overall responsibility for maintaining the adequacy of the spare parts inventory. The on-site spare parts inventory may be based on the vendor's recommendations and shall be modified on an as-needed basis.

47. EPA Review and Comment on CEMS Operation and Maintenance Plan. EPA may provide written comments on the CEMS Operation and Maintenance Plan submitted by BPP, in whole or in part, or EPA may decline to comment, as provided in this Paragraph.

a. If EPA provides written comments within sixty (60) days of receiving a CEMS O&M Plan, then within forty-five (45) days of receiving such comments BPP shall either: (a) modify and implement the Plan consistent with EPA's written comments, or (b) submit the matter for dispute resolution under Part XIV of the Consent Decree.

b. After sixty (60) Days from the date of BPP's submission of a CEMS O&M Plan, EPA may nonetheless provide written comments requiring changes to the Plan, which BPP shall thereafter implement unless implementation of the written comments would (1) be unduly burdensome given the degree to which BPP has proceeded with implementing the CEMS O&M Plan or (2) would be otherwise unreasonable. If BPP determines that implementation of the written comments is unduly burdensome or otherwise unreasonable, it shall so notify EPA. Within sixty (60) days of receiving BPP's position EPA may either accept BPP's position or invoke dispute resolution pursuant to Part XIV of the Consent Decree.

c. Upon the expiration of sixty (60) days from the date of BPP's submission of a CEMS O&M Plan, or upon completion of any Dispute Resolution process under Part XIV of the Consent Decree regarding a submission, BPP shall implement the CEMS O&M Plan in accordance with the requirements and schedule within the Plan.

48. <u>CEMS Root Cause Failure Analysis</u>. For any CEMS having a downtime greater than 5% of the total time for each of two consecutive calendar quarters, BPP shall conduct a CEMS Root Cause Failure Analysis and develop a corrective action plan to promptly address the findings of the CEMS Root Cause Failure Analysis. The CEMS Root Cause Failure Analysis shall include the following elements, at a minimum:

a. An identification and detailed analysis setting forth the root cause(s) of the CEMS downtime;

b. The steps, if any, taken to limit the duration of the CEMS downtime;

c. An analysis of the measures reasonably available to prevent the root cause(s) of the CEMS downtime from recurring. This analysis shall include an evaluation of possible design, operational, and maintenance measures. For any CEMS for which a Root Cause Failure Analysis is required twice within 12 consecutive calendar quarters, BPP shall retain an independent third party to evaluate BPP's assessment of CEMS downtime cause(s), which may include recommendations for additional corrective actions and/or modifications to BPP's CEMS O&M Plan.

The findings of the CEMS Root Cause Failure Analysis and corrective action plan, including a schedule for implementation, shall be submitted to EPA in a written report included with the first semi-annual report required by Part VIII of the Consent Decree following completion of the Root Cause Failure Analysis.

49. Corrective Action. The corrective action plan shall require BPP to undertake as expeditiously as reasonably possible such reasonably available corrective actions as are necessary to correct the cause of the CEMS monitor downtime and to prevent a recurrence of the root cause(s) identified in the CEMS Root Cause Failure Analysis. The corrective action plan shall include a description of any corrective actions already completed or, if not complete, a schedule for their implementation including proposed commencement and completion dates.

a. After a review of a CEMS Root Cause Failure Analysis and corrective action plan, EPA may notify BPP in writing of (1) any deficiencies in the corrective actions listed in the findings; and/or (2) any objections to the schedules of implementation of the corrective actions and explain the basis for EPA's objections.

i. If BP has not yet commenced implementation of the corrective plan, BP will implement an alternative or revised corrective action or implementation schedule based on EPA's comments.

ii. If a corrective action that EPA has identified as deficient has already commenced or is already completed, then BP is not obligated to implement the corrective action identified by EPA. However, BP shall be on notice that EPA considers such corrective action deficient and not acceptable for remedying any subsequent, similar root cause(s) of any future CEMS monitor downtime.

b. If EPA and BP cannot agree on the appropriate corrective action(s) or implementation schedule(s), if any, to be taken in response to a CEMS Root Cause Failure Analysis, either party may invoke the Dispute Resolution provisions of Part XIV of the Consent Decree.

## J. **Benzene Waste NESHAP**

Summary: BPP shall undertake the following measures to minimize or eliminate fugitive benzene waste emissions at its Whiting Refinery. Unless otherwise stated, all compliance requirements shall commence on the Date of Entry of the Consent Decree. Nothing in this Section shall relieve BPP of its independent obligation to comply with the requirements of the Benzene Waste Operations NESHAP.

50. Facility Compliance Status.

a. Compliance Option. BPP shall comply with the compliance option set forth at 40 C.F.R. § 61.342(e) (the "6 BQ Option" or "6 Mg Option") of the Benzene Waste Operations NESHAP.

b. Changes to Compliance Option. BPP shall not change the compliance status of the Whiting Refinery from the 6 BQ Option to the 2 Mg compliance option. Any change in compliance strategy not expressly prohibited by this Section J must be accomplished in accordance with the requirements of the Benzene Waste Operations NESHAP.

c. Organic Benzene Wastes. BPP shall ensure that waste management units at the Whiting Refinery handling Organic Benzene Wastes are in compliance with all standards applicable to such waste management units under the Benzene Waste Operations NESHAP.

d. Aqueous Benzene Wastes. For purposes of complying with the 6 Mg Option, all waste management units at the Whiting Refinery handling Aqueous Benzene Wastes shall either: (1) meet the applicable control standards of the Benzene Waste Operations NESHAP, or (2) have their uncontrolled benzene quantity count toward the 6 Mg compliance limit. Nothing in this sub-paragraph shall be construed to limit the ability of BPP to treat and manage Aqueous Benzene Wastes in accordance with the requirements of 40 C.F.R. § 61.355(k)(4).

e. Annual TAB Report. Beginning on April 1, 2012 for the calendar year 2011 TAB report and continuing thereafter on or before each April 1st, BPP shall submit its annual TAB report for the preceding calendar year required pursuant to 40 C.F.R. § 61.357(d)(2).

51. Waste Stream and Wastewater System Compliance Audit. BPP certifies that it has completed and, on January 25, 2010, submitted to EPA a report on a comprehensive Waste Stream and Wastewater System Compliance Audit, conducted by an independent third-party, of the Whiting Refinery's benzene waste stream inventory, TAB calculation, all waste management units, and entire wastewater treatment system in

order to assess compliance with all applicable Benzene Waste Operation NESHAP requirements. BPP further certifies that, as reported in the January 25, 2010 report, it has completed implementation of all corrective actions necessary to remedy the findings of the Waste Stream and Wastewater System Compliance Audit.

52. Carbon Canisters. At all locations within the Whiting Refinery where carbon canisters are currently installed and used as the control device for complying with the Benzene Waste Operations NESHAP, BPP shall implement and comply with the following:

a. Dual Carbon Canisters/Beds.

i. Except as provided for in sub-paragraph 52.b, by no later than 12 months after the Date of Entry of the Consent Decree, BPP shall install primary and secondary carbon canisters and operate them in series (the "dual-canister" option). BPP may comply with the requirements of the dual canister option required under this sub-paragraph by using a single canister with a "dual carbon bed" if the dual carbon bed configuration allows for breakthrough monitoring between the primary and secondary beds in accordance with this sub-paragraph.

ii. Breakthrough monitoring. BPP shall conduct breakthrough monitoring between the primary and secondary carbon canisters or beds when there is actual flow to the carbon canister. Such monitoring shall be conducted in accordance with the frequency specified in 40 C.F.R. § 61.354(d) using as the design basis the applicable breakthrough definition specified in sub-paragraph 52.a.iii. If a carbon canister or bed becomes unsafe to monitor because it is located within a temporary exclusion zone, BPP shall monitor the canister or bed as soon as is practicable after the exclusion zone is no longer in effect, but in no case later than the end of the normal monitoring interval for the canister or bed or within 3 days of the end of the exclusion period, whichever is sooner. BPP shall include in its semi-annual report a list of all canisters or beds which BPP has designated as unsafe to monitor during the reporting period.

iii. Breakthrough definition. BPP may use either 50 ppmv VOC or 1 ppmv benzene as the design value for the primary carbon canister or bed. BPP shall immediately replace the primary carbon canister or bed when the design value for the primary canister or bed is exceeded (as monitored between the primary and secondary carbon canister or carbon bed). Unless both the primary and secondary carbon canisters or beds are replaced with fresh ones, the original secondary carbon canister or bed shall become the new primary carbon canister or bed and a fresh secondary carbon canister or bed shall be installed. In all cases, any carbon canister or bed used as the primary unit shall have sufficient capacity to meet the breakthrough definition of this sub-paragraph. For purposes of this sub-paragraph 52.a, "immediately" means no later than within twenty-four (24) hours.

iv. BPP shall maintain a sufficient supply of fresh carbon canisters and carbon beds at the Whiting Refinery at all times.

v. For any new waste management unit(s) or refinery process unit(s) at the Whiting Refinery where carbon canisters will be installed and used as the control device for complying with the Benzene Waste Operations NESHAP, BPP shall comply with the dual-canister option, except as provided in sub-paragraph 52.b.

b. Single Carbon Canisters.

i. Permitted locations. After the Date of Entry, for any carbon canister at the Whiting Refinery subject to this Paragraph 52, BPP may use the "single canister" option described in this sub-paragraph at the following locations:

(1) If BPP demonstrates that it is technologically infeasible or unsafe to comply with the dual-canister option under sub-paragraph 52.a, BPP may use a single carbon canister at that specific location. BPP shall submit a written request to EPA to comply with the "single canister" option for each such canister. This request shall specifically identify each carbon canister for

which BPP claims that it is technologically infeasible or unsafe to comply with the dual-canister option and shall provide a detailed explanation of the specific technical and/or safety reasons for the request. This request shall be subject to EPA approval.

(2) BPP may use a single carbon canister at locations where breakthrough, as defined in this sub-paragraph 52.b, has been documented as occurring less than once per calendar year.

(3) BPP may use a single carbon canister on temporary waste management units (*e.g.*, FRAC or Baker tanks), provided that such temporary units are used for no more than 30 Days.

(4) Until December 31, 2015, BPP may use single carbon canisters at the DAF unit and API Separator that are subject to sub-paragraph 60.g. Within 12 months after the Date of Entry and continuing until December 31, 2015, BPP shall optimize the use of bio-filters or other control or treatment technologies to minimize breakthrough at the single carbon canisters at the DAF and API Separator.

ii. Breakthrough monitoring. By no later than the Date of Entry, BPP shall conduct breakthrough monitoring for each single carbon canister at the Whiting Refinery when there is actual flow to the canister. Such monitoring shall be conducted in accordance with all requirements specified in 40 C.F.R. § 61.354(d) using as the design basis the applicable breakthrough definition specified in sub-paragraph 52.b.iii, but in no case less frequently than on a monthly basis. If a carbon canister or bed becomes unsafe to monitor because it is located within a temporary exclusion zone, BPP shall monitor the canister or bed as soon as is practicable after the exclusion zone is no longer in effect, but in no case later than the end of the normal monitoring interval for the canister or bed or within 3 days of the end of the exclusion period, whichever is sooner. BPP shall include in its semi-annual report a list of all canisters or beds which BPP has designated as unsafe to monitor during the reporting period.

iii. Breakthrough definition. Single carbon canisters will be replaced immediately when breakthrough is detected as follows:

(1) For canisters less than or equal to 55-gallon drum size, breakthrough is any reading of VOC or benzene above background.

(2) For canisters larger than 55 gallons, breakthrough is defined as either:

a. 50 ppmv VOC; or

b. 1 ppmv benzene. To use 1 ppmv benzene, canisters must be monitored for VOC. When a reading of 10 ppmv VOC is detected, monitoring for benzene must be conducted on the following schedule:

i. Daily if the representative historical replacement interval is two weeks or less, or

ii. Three times per week and not on consecutive days, if the representative historical replacement interval is greater than two weeks.

(3) For purposes of this sub-paragraph 52.b, the term "immediately" shall mean: within eight (8) hours for single canisters with representative historical replacement intervals of two weeks or less; or within twenty-four (24) hours for single canisters with a representative historical replacement interval of more than two weeks.

iv. Canister Replacement. Single carbon canisters may be replaced with a dual carbon canister or carbon bed system at any time provided EPA is notified and the monitoring requirements for single canisters are continued until the second canister or bed is installed. BPP shall comply with the monitoring requirements for dual-carbon canisters or dual-carbon beds provided in sub-paragraph 52.a upon installation of such system, and BPP shall notify EPA of such replacement in its next quarterly report submitted pursuant to Part VIII of the Consent Decree.

c. Alternative Control/Treatment Devices. Nothing in Paragraph 52 of this Section of the Consent Decree is intended to preclude BPP from electing to use other control devices at the Whiting Refinery to comply with the Benzene Waste Operations NESHAP instead of or in addition to carbon adsorption, provided that such other control technology meets all applicable control and/or treatment requirements under the Benzene Waste Operations NESHAP and the compliance monitoring point is unaffected by the use of such other control devices. If BPP elects to use another control technology, BPP shall submit written notification to EPA in its next semi-annual report submitted pursuant to Part VIII of the Consent Decree providing both the location where such other control technology shall be used instead of or in addition to carbon adsorption and a description of the other technology to be used.

d. Records. Records regarding compliance with Paragraph 52 shall be maintained in accordance with 40 C.F.R. § 61.356(j)(10).

53. Annual Program. BPP shall continue to implement an annual program of reviewing process information for the Whiting Refinery, including but not limited to construction projects, to ensure that all new benzene waste streams are included in the Whiting Refinery's waste stream inventory and TAB Report, and to ensure that all new waste management units are properly accounted for and managed in accordance with the Benzene Waste Operations NESHAP.

54. Laboratory Audits. BPP shall conduct audits of all laboratories that perform analyses of samples used to determine compliance with the Benzene Waste Operations NESHAP at the Whiting Refinery. These audits shall review procedures and methods in order to ensure that proper analytical and quality assurance practices are followed. BPP shall conduct such audits at each laboratory at least every two (2) calendar years from the date of the last audit conducted by the Whiting Refinery pursuant to Paragraph 19.H of the 2001 Consent Decree or prior to using a new lab for analysis of benzene samples.

55. Benzene Spills. At least once per calendar year, BPP shall review all CERCLA reportable spills at the Whiting Refinery to determine if benzene waste was generated. BPP shall account for all benzene wastes generated through such spills in its annual TAB calculation and report. All benzene wastes generated through such spills that are not managed solely in controlled waste management units shall count toward the 6 Mg compliance limit.

56. Training. BPP shall:

a. Develop and implement annual training for all employees at the Whiting Refinery with responsibility to sample benzene waste streams;

b. Establish standard operating procedures for all control devices used to comply with the Benzene Waste Operations NESHAP and include training on such procedures as part of the annual training for employees assigned to operate these devices; and

c. Ensure that third-party contractors hired to perform any requirement of this Section J of the Consent Decree have a proper training program to implement the provisions of this Paragraph.

57. Waste/Slop Oil Management. BPP shall maintain records of waste/slop oil movements for waste streams (organic or aqueous) that are not controlled, as identified in the slop oil plan prepared by the Whiting Refinery. EPA may review the plan and recommend revisions to add uncontrolled waste streams resulting from waste/slop oil movements, in accordance with the provisions of 40 C.F.R. Part 61, Subpart FF.

58. Sampling (6 Mg/yr). BPP shall conduct quarterly "end-of-line" ("EOL") benzene determinations as follows:

a. If no changes will be made to the sampling locations or methods for flow calculations currently used in the quarterly and annual benzene determinations for the Whiting Refinery, BPP shall comply with and continue sampling under the refinery's existing EOL Sampling Plan;

b. If BPP proposes to make any changes to the sampling locations or methods for flow calculations to be used in the quarterly benzene determinations for the Whiting Refinery, within 30 Days after the Date of Entry of the Consent

Decree, BPP shall submit a revised EOL Sampling Plan that shall contain any proposed changes. The revised EOL Sampling Plan shall be subject to EPA approval. BPP shall comply with and commence sampling under the revised EOL Sampling Plan by no later than the first full Calendar Quarter following submittal of the plan to EPA, regardless of whether the plan is approved at that time;

c. On an annual basis, BPP shall sample all uncontrolled waste streams that count toward the 6 Mg compliance limit and contain greater than 0.05 Mg/yr of benzene; and

d. If changes in processes, operations, or other factors lead BPP to conclude that the EOL Sampling Plan for the Whiting Refinery may no longer provide a representative basis for estimating the Whiting Refinery's annual or quarterly EOL benzene quantity, then by no later than ninety (90) Days after BPP makes this determination, BPP will submit to EPA a newly proposed revised EOL Sampling Plan. Upon receipt of EPA approval, BPP shall commence sampling consistent with the requirements and schedule contained in the newly approved EOL Sampling Plan.

59. Groundwater Conveyance Systems. BPP shall manage all groundwater conveyance systems located at the Whiting Refinery in accordance with, and to the extent required by, 40 C.F.R. § 61.342(a).

60. Miscellaneous Measures. By no later than the Date of Entry, BPP shall implement the measures identified in subparagraphs a.-f:

a. BPP shall conduct monthly visual inspections of all water traps within its individual drain systems that are subject to the Benzene Waste NESHAP;

b. BPP shall identify/mark all area drains that are segregated stormwater drains;

c. BPP shall include each controlled individual drain system subject to the Benzene Waste Operations NESHAP at the Whiting Refinery on all inspection schedules pertaining to Benzene Waste Operation NESHAP compliance, and shall conduct inspections of each such drain system in accordance with such schedules set forth in 40 C.F.R. Part 61, Subpart FF;

d. BPP shall monitor the flow indicators on all conservation vents on process sewers for detectable leaks on a weekly basis;

e. BPP shall conduct quarterly monitoring of oil/water separators in benzene service in accordance with 40 C.F.R. § 61.347; and

f. BPP shall account for and include in the annual TAB Report all slop oil recovered from its oil/water separators or sewer system until recycled or put into a feed tank, in accordance with 40 C.F.R. § 61.342(a). All tanks handling waste benzene shall meet the control standards specified in 40 C.F.R. § 61.343 or § 61.351, except that Tank P1 and Tank P2 at the Whiting Refinery shall meet the tank control standard at 40 C.F.R. § 61.343.

g. <u>DAF Installation/API Separator Covers</u>. By no later than December 31, 2015, BPP shall complete construction and installation of a new Dissolved Air Flotation (DAF) unit at the Whiting Refinery. By no later than December 31, 2015, BPP shall complete construction and installation of new covers for the API Separator at the Whiting Refinery. By no later than December 31, 2015, emissions from both the new DAF and API Separator shall be routed to control devices, such as carbon canisters, that meet all applicable control and/or treatment requirements under the Benzene Waste Operations NESHAP.

61. <u>Heat Exchange Systems and Cooling Towers</u>.

a. <u>Applicability</u>. In complying with the National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, 40 C.F.R. Part 63, Subpart CC, BPP may only claim that a heat exchange system is not in "organic HAP service" pursuant to 40 C.F.R. § 63.654(b)(2) if the heat exchange system only cools process fluids that contain less than 2.5% by weight of total HAPs (as listed in Table 1 to Subpart CC).

b. <u>TAB Reporting</u>. Beginning with the first TAB Report submitted for the refinery after October 29, 2012, and for each TAB report thereafter, BPP shall report as a separate line-item the entire benzene quantity identified by monitoring conducted pursuant to 40 C.F.R. §63.654(c) at all heat exchange systems at the Whiting Refinery subject to 40 C.F.R. Part 63, Subpart CC and those identified above in sub-paragraph 61.a. This line-item shall not be counted towards the uncontrolled benzene quantity under the 6 Mg Option.

62. Semi - Annual Benzene Waste NESHAP Report. By no later than February 15 and August 15 of each calendar year after the Date of Entry, BPP shall submit a semi-annual report to EPA that includes the following information for the Whiting Refinery regarding compliance with the Benzene Waste NESHAP requirements of this Section (the "Semi-Annual Benzene Waste NESHAP Report"). Each Semi-Annual Benzene Waste NESHAP Report shall include the following information for the two most recently completed Calendar Quarters (the "reporting period"):

a. EOL Report:

i. As part of each Semi-Annual Benzene Waste NESHAP Report, BPP shall submit to EPA the following information:

(1) a list of all waste streams sampled at the Whiting Refinery pursuant to Paragraph 58;

(2) the results of the quarterly and annual sampling conducted pursuant to Paragraph 58, including the results of the benzene analysis for each sample;

(3) the computation of the EOL benzene quantity for each quarter; and

(4) any other related information required under a revised EOL Sampling Plan if submitted pursuant to Paragraph 58.

ii. As part of the EOL Report, BPP shall use all sampling results and approved flow calculation methods pursuant to Paragraph 58 to calculate and report a quarterly and a calendar year uncontrolled benzene quantity for the Whiting Refinery against the 6 Mg Option.

iii. If the quarterly uncontrolled benzene quantity (for any Calendar Quarter during the reporting period) at the Whiting Refinery exceeds 1.5 Mg or the annual uncontrolled benzene quantity exceeds 6 Mg, then BPP shall, as specified below, conduct a Root Cause Failure Analysis and develop a corrective action plan (including a schedule for completing the corrective actions) to promptly address the findings of the

Root Cause Failure Analysis. The findings of the Root Cause Failure Analysis and corrective action plan shall be submitted to EPA in a written report within 30 Days following completion of the Root Cause Failure Analysis. This corrective action plan shall be subject to EPA approval. BPP shall begin to implement the corrective action plan by no later than 60 Days after submission to EPA, and shall complete the corrective action pursuant to the proposed schedule.

(1) Root Cause Failure Analysis. The Root Cause Failure Analysis required under this sub-paragraph shall include the following elements:

a. If the root cause(s) of the quarterly or annual uncontrolled benzene exceedance is attributable to at least one discrete event, or to at least one discrete series of related events, resulting in 0.5 Mg or more of uncontrolled benzene, BPP shall include an estimate of the quantity of uncontrolled benzene emitted into the ambient air along with the calculations used to determine such emissions;

b. The steps, if any, taken to limit the duration and/or quantity of uncontrolled benzene exceeding 1.5 Mg per quarter or the 6 Mg Option;

c. A detailed analysis setting forth the root cause(s) for exceeding 1.5 Mg per quarter or the 6 Mg Option; and

d. An analysis of the measures reasonably available to prevent the root cause(s) for the exceedance from recurring. This analysis shall include an evaluation of possible design, operational, and maintenance measures. This analysis shall also include a discussion of alternative measures that are reasonably available, their relative probable effectiveness, and their relative costs.

(2) Corrective Action Plan. The corrective action plan required under this sub-paragraph shall require BPP to undertake as expeditiously as possible any such interim and/or long-term corrective actions as are necessary and consistent with good air pollution control practices to prevent a recurrence of the root cause(s) identified in the Root Cause Failure Analysis. The corrective action plan shall include a description of any corrective actions already completed or, if not complete, a schedule for their implementation including proposed commencement and completion dates.

iv. BPP shall identify all labs used during the quarter to analyze benzene waste samples collected at the Whiting Refinery pursuant to this Section J, and BPP shall provide the date of the most recent audit of each lab.

b. Carbon Canister Report.

i. As part of the second Semi-Annual Benzene Waste NESHAP Report required by the Consent Decree, BPP shall submit a project completion report to EPA detailing the actions performed to comply with the requirements of Paragraph 52. BPP shall include a list of all locations within the refinery using the dual-canister option, the installation date of each such dual-canister, and the date that each dual-canister was put into operation.

ii. As part of each Semi-Annual Benzene Waste NESHAP Report, for all locations at which single carbon canisters are used, BPP shall identify each such location and provide the results of all breakthrough monitoring and carbon canister change-outs that occurred during the reporting period. For each single carbon canister, BPP shall also identify: i) the date(s) and approximate time when breakthrough was first detected; and ii) for each breakthrough event, the date and time when carbon canister change-out occurred. BPP shall also include in each semi-annual report a list of all canisters or beds which BPP has designated as unsafe to monitor during the reporting period.

c. Audit Reporting: As part of each Semi-Annual Benzene Waste NESHAP Report, BPP shall identify all labs audited pursuant to the requirements of Paragraph 54 during the reporting period, and shall submit the results and the reports regarding any such audits. For each lab audited, BPP shall also provide a description of the methods used in the audit.

d. Training Reporting: As part of each Semi-Annual Benzene Waste NESHAP Report, BPP shall identify the employees who received training during the reporting period pursuant to the requirements of Paragraph 56, and shall describe the training these employees received. BPP shall also describe the training scheduled to be performed during the next reporting period.

e. BPP shall certify each Semi-Annual Benzene Waste NESHAP Report required in accordance with the certification statement required under Paragraph 102 of the Consent Decree.

## K. Leak Detection and Repair

63. NSPS Applicability. Upon the Date of Entry, each "process unit" (as defined by 40 C.F.R. § 60.590a(e)) at the Whiting Refinery shall be an "affected facility" for purposes of 40 C.F.R. Part 60, Subpart GGGa, and shall be subject to and comply with the requirements of Subpart GGGa no later than one year from the Date of Entry, except as specifically provided in this Paragraph.

a. The requirements of 40 C.F.R. Part 60, Subpart GGGa, shall not apply to compressors at the Whiting Refinery.

b. Process units on which construction commenced prior to January 4, 1983, shall not be subject to the requirements in 40 C.F.R. § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

c. Entry of this Consent Decree satisfies the following notification and testing requirements that are triggered by initial applicability of 40 C.F.R. Part 60, Subparts A and GGGa: 40 C.F.R 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a) and 60.487a(e).

d. The two consecutive months of monitoring that BPP previously conducted for purposes of 40 C.F.R. Part 60, Subpart GGGa in 2011 satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 C.F.R. Part 60, Subpart GGGa for the following units of the Whiting Refinery: FCU 500, VRU 300, 4UF, Alky Analyzer, ARU, Indiana Tank Field, J&L Tank Field, Lake George Tank Field, Marketing Terminal, Oil Movements Diluent, Oil Movements North, South Tank Field and Stieglitz Park Tank Field.

Nothing in this Paragraph or in Appendix B to this Consent Decree shall relieve BPP of its independent obligation to comply with the requirements any other federal, state or local LDAR regulation that may be applicable to Equipment at the Whiting Refinery.

64. Enhanced Leak Detection and Repair. BPP shall implement and comply with the requirements of the Enhanced Leak Detection and Repair Program ("ELP") set forth in Appendix B to this Consent Decree by the dates specified therein. The requirements of Appendix B are in addition to the applicable requirements under 40 C.F.R. Part 60, Subpart GGGa; Part 61, Subparts J and V; and Part 63, Subparts H and CC. The terms "in light liquid service" and "in gas/vapor service" shall have the definitions set forth in the applicable provisions of 40 C.F.R. Part 60, Subpart GGGa; and Part 63, Subpart CC.

## L. Sulfur Recovery Plant and Sulfur Pits

Summary: BPP is required to accept NSPS Subpart Ja applicability for its Sulfur Recovery Plant ("SRP"), and to route all emissions from its sulfur pits and sealed sulfur collection drums such that all emissions are treated and included as SRP emissions subject to 40 C.F.R. Part 60, Subparts A and Ja.

65. Sulfur Recovery Plant and NSPS Applicability. The Whiting Refinery currently has a single SRP with three parallel Claus sulfur recovery units, with two Tail Gas Units (an SBS unit and a Beavon Stretford unit) serving as control devices. As a part of WRMP, two new Claus sulfur recovery units will be added to the SRP, and the SBS

and Beavon Stretford units will be shut down and replaced by two new Claus Offgas Treaters (COT1 and COT2), as provided in this Section. Upon completion of WRMP, the design of the SRP will allow tail gas from all five Claus sulfur recovery units to be routed to either or both of the two new COTs. By no later than the Date of Entry, the Whiting Refinery SRP shall be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, for all pollutants applicable to SRPs, and shall be subject to and comply with all applicable requirements of 40 C.F.R. Part 60, Subparts A and Ja except as provided in this Paragraph 65.

a. Each of the two new Claus sulfur recovery units and Claus Offgas Treaters being installed as a part of WRMP shall achieve and thereafter maintain compliance with the emission limit in 40 C.F.R. § 60.102a(f)(1)(i) and the monitoring requirements in 40 C.F.R. § 60.106a(a)(1) by no later than 60 days after achieving the maximum production rate at which the unit will be operated, or 180 days after initial startup, whichever comes first.

b. The Beavon Stretford and SBS units at the Whiting Refinery SRP shall be shut down and permanently removed from service by no later than 180 days after the initial startup of the later of the two new Claus sulfur recovery units and associated Claus Offgas Treaters (COT1 or COT 2) being installed as a part of WRMP. Initial startup of the two new Claus sulfur recovery units and the Claus Offgas Treaters shall be by no later than the initial startup of the New Coker. Until the Beavon Stretford unit is shut down, BPP shall continue to monitor emissions from that unit and determine compliance with the emission limits in 40 C.F.R. § 60.102a(f)(1) in accordance with the monitoring procedure specified in Appendix C.

66. <u>SRP Emission Limits</u>. Beginning no later than the date by which the later of the two new Claus Sulfur Recovery Units and associated Claus Offgas Treaters being installed as a part of WRMP is required to achieve compliance under Paragraph 65.a of this Section, the Whiting Refinery SRP shall comply with the following requirements:

a. An $SO_2$ emission limit of 194.8 tons per each rolling 12-month period. Compliance with this limit shall be determined each month by adding the total emissions for that month to the total emissions for the preceding 11 months. Total emissions for each month shall be determined with CEMS emission data converted by the following equation:

$$E = \left( \frac{F \times h \times C \times MW}{V_m \times 2000 \times 10^6} \right)$$

| | | |
|---|---|---|
| E | = | TGTU $SO_2$ Emissions in tons per month |
| F | = | Measured total TGTU incinerator stack flow rate, dscf at standard conditions (60° F), for the month |
| C | = | Average concentration of $SO_2$ in TGTU incinerator exhaust for the month, in ppmvd |
| MW | = | Molecular weight of $SO_2$ = 64.06 |
| Vm | = | 379.4 dscf of gas per lb-mol at standard conditions (60° F) |
| 2000 | = | conversion factor for 2000 pound per ton |
| $10^6$ | = | conversion factor for ppmv to volume fraction |

b. 40 C.F.R. § 60.102a (f)(1)(i) during all periods of operation of the SRP, other than periods of Startup, Shutdown or Malfunction of the SRP or malfunction of a Tail Gas Unit (TGU) to the extent provided under 40 C.F.R. § 60.8.

c. At all times, including, but not limited to, periods of Startup, Shutdown, Malfunction and maintenance, BPP shall, to the extent practicable, operate and maintain the SRP, including its TGU, its sulfur pits and sealed sulfur collection drums, any supplemental control devices on the SRP, and Pit 2400 and the molten sulfur storage tanks, in accordance with its obligation to minimize emissions through implementation of good air pollution control practices as required by 40 C.F.R. § 60.11(d).

67. SRP Operations and Maintenance.

a. By no later than 60 Days after the Date of Lodging, BPP shall submit to EPA an updated plan for operating and maintaining the SRP, including, but not limited to, the existing TGUs, sulfur pits A, B, C, and 2400, as well as upstream process units, in accordance with good air pollution control practices for minimizing emissions.

b. By no later than December 31, 2012, BPP shall submit to EPA an updated plan ("SRP O&M Plan") for operating and maintaining the SRP, including, but not limited to, the two new Claus sulfur recovery units and Claus Offgas Treaters, the sealed sulfur collection drums, the molten sulfur storage tanks, as well as upstream process units, in accordance with good air pollution control practices for minimizing emissions.

c. BPP shall comply with the most recently submitted SRP O&M Plan at all times, including, but not limited to, periods of Startup, Shutdown, and Malfunction of the SRP. BPP may make reasonable modifications to the SRP O&M Plan submitted under this Paragraph, provided that BPP provides EPA with a copy of the modification in its next semi-annual report submitted pursuant to Part VIII of the Consent Decree.

68. <u>Sulfuric Acid Mist Testing</u>. By no later than 180 days after the commencement of operations of the two new COTs (COT1 and COT2), BPP shall conduct a one-time test at each COT stack under representative conditions to measure the sulfuric acid mist ("SAM") emission rate.

69. <u>Sulfur Pit and/or Sulfur Collection Drum and Tank Emissions</u>.

a. <u>Sulfur Pit Emissions</u>. By no later than the Date of Entry, BPP shall (i) comply with the requirements of 40 C.F.R. § 60.102a(f) as it applies to Sulfur Pits A, B and C and (ii) continue to operate and maintain the following control and monitoring equipment until Pits A, B, C and 2400 are decommissioned:

i. Pit sweep system for Pits A, B, C and 2400;

ii. Temperature indicators located at each eductor inlet at Pits A, B, C and 2400; and

iii. Caustic scrubber to treat emissions from Pits A, B, C and 2400 in the event that pit sweep emissions are routed to the Beavon Stretford unit.

b. <u>Sulfur Pit 2400 Degas System</u>. By no later than the Date of Entry, BPP shall, to the extent practicable, maintain and operate the newly redesigned degas system to minimize the entrainment of $H_2S$ vapor in the sulfur routed to Pit 2400 in a manner consistent with good air pollution control practice for minimizing emissions.

c. Emissions From Sealed Sulfur Collection Drums and Molten Sulfur Tanks.

i. By no later than 180 Days after initial startup of the New Coker, BPP shall replace Sulfur Pits A, B and C with sealed sulfur collection drums, and shall replace Pit 2400 with molten sulfur storage tanks. By no later than the date that BPP replaces Sulfur Pits A, B and C with sealed collection drums and Pit 2400 with storage tanks, BPP shall route all sulfur emissions from the sealed sulfur collection drums and the molten sulfur storage tanks such that they are treated, monitored, and included as part of the SRP's emissions subject to the NSPS Subpart Ja limit for $SO_2$, 40 C.F.R. § 60.102a (f)(1)(i).

ii. For a period of one year commencing from the first use of each molten sulfur storage tank, BPP shall monitor on a continuous basis and report to EPA on a semi-annual basis the duration of all relief valve releases from each molten sulfur storage tank.

iii. Nothing in this subparagraph 69.c shall preclude BPP from undertaking maintenance on the sealed sulfur collection drums consistent with the provisions of 40 C.F.R. § 60.102a(f)(3), or the molten sulfur storage tanks consistent with subparagraph 72.b of Section M of this Consent Decree (Requirements for Certain Tanks).

## M. Requirements for Certain Tanks

70. Stormwater Equalization Tank (TK-5052): BPP shall continue to operate and maintain an external floating roof on the stormwater equalization tank designated as Tank 5052 at the Whiting Refinery consistent with the requirements of 40 C.F.R. § 61.351(a)(2).

71. Brine Treatment Tanks (TK-101, TK-102, TK-103 and TK-104):

a. The Brine Treatment Tanks (TK-101, TK-102, TK-103 and TK-104) at the Whiting Refinery shall be equipped with fixed roofs and shall be vented to (i) an iron sponge control system followed by (ii) a carbon canister meeting the requirements of 40 C.F.R. § 61.349(a)(2) and Paragraph 52 of Section J of this Consent Decree (Benzene Waste NESHAP). Subject to EPA approval, BPP shall have the ability to utilize an alternative to the carbon canister authorized by 40 C.F.R. § 61.349(a)(2).

b. BPP shall monitor and record daily average $H_2S$ concentration on the outlet of the iron sponge system and daily total vapor flow to the iron sponge system. Process analyzers calibrated in accordance with manufacturer's recommendations may be used for these purposes.

72. Sulfur Storage Tanks (TK-315 and TK-316):

a. Each of the sulfur storage tanks designated as TK-315 and TK-316 at the Whiting Refinery shall be steam or nitrogen blanketed and equipped with a water eductor system that routes $H_2S$ emissions back to the sulfur recovery plant at all times except during periods when the tanks are vented to atmosphere to allow for maintenance on equipment associated with the tank (*i.e.*, valves and level transmitters).

b. Tanks TK-315 and TK-316 shall not be vented to atmosphere except during periods of maintenance on equipment associated with the tank, and during those periods for no more than 100 hours per rolling12-month period.

73. Off-Spec Brine Tanks (TK-3559 and TK-3560):

a. BPP shall continue to operate and maintain an internal floating roof on each Off-Spec Brine Tank (TK-3559 and TK-3560) consistent with the requirements of 40 C.F.R. § 61.351(a)(1).

b. VOC emissions from the Off-Spec Brine Tanks shall not exceed a total of 2.1 tons per rolling 12-month period.

c. For each of the Off-Spec Brine Tanks, BPP shall:

i. monitor and record throughput on a monthly total basis; and

ii. sample the material in the tank off the tank's floating suction line and measure and record the Reid Vapor Pressure ("RVP") of any oil layer once per month.

d. Using the throughput data collected under Paragraph 73.c.i, and the most recent RVP measurement collected under Paragraph 73.c.ii, BPP shall use USEPA's "TANKS" model to determine and record, on a monthly basis, the monthly and rolling12-month VOC emissions from the Off-Spec Brine Tanks.

e. Except for periods when a tank is out of service, BPP shall maintain in each Off-Spec Brine Tank a level sufficient to assure that the floating roof remains in contact with the liquid in the tank.

74. Coker Feed Tank (TK-6254):

a. The Coker Feed Tank (TK-6254) shall be equipped with a fixed roof, shall be nitrogen blanketed and shall be vented to an iron sponge control system except during periods when the iron sponge is offline for maintenance.

b. Emissions of $H_2S$ from the TK-6254 shall not exceed 2.84 tons per rolling 12-month period. Emissions during periods when the iron sponge is offline for maintenance shall be included in determining compliance with this emission limit.

c. BPP shall monitor and record the daily average $H_2S$ concentration at the outlet of the iron sponge system and shall determine the daily average vapor flow based on the nitrogen purge rate to TK-6254. The $H_2S$ concentration and nitrogen purge flow will be used to calculate the $H_2S$ emissions rate. Process analyzers calibrated in accordance with the manufacturer's recommendations, may be used for this purpose.

d. Emissions of VOC from the TK-6254 shall not exceed 10.0 tons per rolling 12-month period. On a monthly basis, BPP shall (a) monitor the VOC concentration at the outlet of the iron sponge system in accordance with the methods used to comply with the requirements for breakthrough monitoring for carbon canisters in Paragraph 52.a.ii and Paragraph 52.b.ii of Section J of this Consent Decree, and (b) record the results of such monitoring.. BPP shall verify and record that flow is present when the VOC concentration is measured at the tank vent. BPP shall determine the monthly average vapor flow based on the nitrogen purge rate to TK-6254. The VOC concentration and nitrogen purge flow will be used to calculate the VOC emissions rate.

75. FLIR Monitoring: Annually, BPP shall use an Optical Gas Imaging Camera to video image and record emissions from the tank roof and related vent systems on the Stormwater Equalization Tank (TK-5052), the brine treatment tanks (TK-101, TK-102, TK-103, TK-104), Off-Spec Brine Tanks (TK-3559, TK-3560), and the Coker Feed Tank (TK-6254). If imaging indicates emissions inconsistent with well maintained floating roof tanks, seals, fittings, or welds, BPP shall inspect and, if necessary, repair the leaks consistent with the underlying Federal, State or local regulations applicable to the tank(s). BPP will report the results of these inspections and any corrective actions required during the next semi-annual Part VIII report.

76. The provisions in this Section will take effect upon startup of each tank or the Date of Entry, whichever is later.

## N. VOC, PM, TRS, and $H_2S$ Emission Reductions from the Whiting Refinery New Coker

Summary: BPP will limit VOC, PM, TRS and $H_2S$ emissions by depressuring the Coke Drum to no more than 2.0 psig prior to venting, by controlling the quality of the makeup water added to the Quench Water System, by requiring a minimum total Quench Water volume subject to a high level trip and a minimum Quench Water Soak Time and by designing the Coke Pit so as to minimize fugitive dust from the coke. The requirements in this Section to control particulate emissions at the Coke Pit are in addition to the coke handling requirements contained in the Whiting Refinery's permit, including an enclosed and wetted coke conveyance system, enclosed coke storage buildings, and other measures to control fugitive PM.

77. Control of VOC, $PM_{TOTAL}$, $PM_{10}$, TRS, and $H_2S$ Emissions from the Whiting New Coker. Upon initial startup of the New Coker, BPP shall not commence Coke Drum Venting until the Coke Drum Overhead Pressure is 2.0 psig or less.

78. New Coker Coke Drum Operating Parameter Limits. Upon initial startup of the New Coker, BPP shall comply with the following operating limits:

a. Total Quench Water added to a coke drum shall be at least 260,000 gallons per cycle or until the water reaches the high level trip in the Coke drum, whichever is less; and

b. Quench Water Soak Time shall be at least 45 minutes per cycle.

79. Control of VOC, TRS, and $H_2S$ Emissions from the Whiting New Coker Quench Water System. Commencing upon the initial startup of the New Coker, for all components and pieces of equipment within the Quench Water System other than the Coke Pit, the Maze (coke fines settling basin), clean water sump and Quench Water Tank, BPP shall maintain a hard-piped system that has no emissions points to the atmosphere.

80. Quench Water Operating Practices.

a. Commencing upon the initial startup of the New Coker, BPP shall use only the following for the New Coker Quench Water Make-Up:

i. Water that is fresh (*i.e.*, water brought into the Whiting Refinery that has not been in contact with process water or process wastewater);

ii. Non-contact cooling water blowdown;

iii. Water that has been stripped in a sour water stripper;

iv. Water from other refinery sources where the water has a TOC concentration of less than 745 ppm and a total sulfide concentration of less than 35 ppm; or

v. Some combination of water from i-iv.

b. Commencing upon the initial startup of the New Coker, BPP shall not feed or dispose of any materials with a TOC concentration of 745 ppm or greater into any New Coker Coke Drum during the quench cycle.

81. Control of Particulate Emissions from the Coke Pit. By no later than the date of initial startup of the New Coker, BPP shall construct a Coke Pit with walls on all four sides that are at least forty feet (40') above the floor of the Coke Pit.

## O. Emission Reductions from Flares and Control of Flaring Events

82. BPP shall implement and comply with the requirements to control and minimize emissions from the flaring devices at the Whiting Refinery set forth in Appendix D to this Consent Decree.

**P. Incorporation of Consent Decree Requirements into Federally Enforceable Permits**

83. Permits. Where any compliance obligation under the Consent Decree requires BPP to obtain a federal, state, or local permit or approval, including any preconstruction, construction, or operating permits, BPP shall submit timely and complete applications and take all other actions necessary to obtain all such permits or approvals.

a. By no later than the Date of Lodging, BPP shall submit all necessary applications and information to IDEM for a permit modification to the WRMP Operating Permit to incorporate the emission limits and standards contained in Part V of this Consent Decree that address EPA's October 16, 2009 Title V Order.

b. BPP shall thereafter timely submit all necessary applications and information to IDEM for a CAA Title I source modification permit for the Whiting Refinery. The application(s) shall seek to obtain all required, federally enforceable permits for the construction of the pollution control technology and/or the installation of equipment necessary to implement the requirements of this Consent Decree. The application(s) shall also seek to incorporate all emissions limits and standards required by the following requirements of this Consent Decree that will survive termination of the Consent Decree:

i. Paragraphs 11, 12.b.i-ii and 13 in Part V, Section A (*FCCU NOx limits*);

ii. Paragraphs 14, 15.b.i-ii and 16 in Part V, Section B (*FCCU $SO_2$ limits*);

iii. Paragraphs 17, 18, 19, 20 and 21 in Part V, Section C (*FCCU PM limits*);

iv. Paragraphs 23, 24, 25, 26 and 27 in Part V, Section D (*FCCU CO limits*);

v. Paragraphs 28, 29 and 30 in Part V, Section E (*FCCU VOC limits*);

vi. Paragraphs 31.b, 32, 33.a-b, 34, 35 and 36 in Part V, Section F (*NOx Heater and Boiler limits*);

vii. Paragraphs 39.a and 40 in Part V, Section G (*$SO_2$ Heater and Boiler limits*);

viii. Paragraph 41 in Part V, Section H (*Fuel Gas Sulfur limits*);

ix. Paragraphs 65, 66 and 69 in Part V, Section L (*Sulfur Recovery Plant and Sulfur Pit*);

x. Paragraphs 71, 72, 73 and 74 in Part V, Section M (*Requirements for Certain Tanks*);

xi. Paragraphs 77, 78, 79, 80 and 81 in Part V, Section N (*Whiting Refinery New Coker*);

xii. Paragraphs 6-13, 15-17, 25-32, 33.b, 34-37, 41-42, 44-46, 48.d-e, 51, 67.c-d, and 69-70 of Appendix D (*Flares and Control of Flaring Events*); and

xiii. All of Part VI (*Emission Credit Generation*).

c. The Parties agree that the incorporation of emission limits and standards into the Title V operating permit for the Whiting Refinery as required by Paragraphs 83.a and 83.b shall be in accordance with the applicable rules for Indiana's consolidated Title V construction and operating permit program.

d. BPP may seek relief under the provisions of Part IX of this Consent Decree ("Force Majeure") for any delay in the performance of any such obligation resulting from a failure to obtain, or a delay in obtaining, any permit or approval required to fulfill such obligation, if BPP has submitted timely and complete applications and has taken all other actions necessary to obtain all such permits or approvals.

## VI. EMISSION CREDIT GENERATION

Summary: This Part addresses the use of certain emissions required by the 2001 Consent Decree and all emissions reductions required by this Consent Decree for the purpose of emissions netting or emissions offsets in any permitting action at the Whiting Refinery initiated after the Date of Entry.

84. Prohibitions on Emission Credits.

a. General Prohibition. BPP shall not generate or use any NOx, $SO_2$, $H_2S$, TRS, reduced sulfur compounds, PM, $PM_{2.5}$, $PM_{10}$, $PM_{TOTAL}$, VOC, or CO emissions reductions ("CD Emission Reductions"), or apply for and obtain any emission reduction credits, that result from any projects conducted or controls utilized pursuant to this Consent Decree as netting reductions or emissions offsets in any PSD, major non-attainment, and/or minor New Source Review permit or permit proceeding.

b. Specific Prohibition on Reductions under 2001 Consent Decree. BPP shall not generate or use any NOx emission reductions, or apply for and obtain any NOx emission reduction credits, that are achieved as a result of the following projects required by the 2001 Consent Decree as netting reductions or emissions offsets in any PSD, major nonattainment, and/or minor New Source Review permit or permit proceeding:

| | | |
|---|---|---|
| 3 Stanolind Power Station Boilers 31, 32, 33, 34 and 36 | Installation of SCRs | Completed December 31, 2010 |
| 1 Stanolind Power Station Boilers 13, 14, 16 and 17 | Shutdown | Completed April 1, 2010 |

85. Exception to Prohibitions on Emission Credits. Notwithstanding the prohibitions set forth in Paragraph 84, BPP may use 8 tons per year (tpy) of VOC, 26 tpy of NOx, 6 tpy of $PM_{10,}$ and 18 tpy of CO from emissions reductions required by this Consent Decree or the 2001 Consent Decree as credits or offsets in any PSD, major non-attainment and/or minor NSR permit or permit proceeding occurring after the Date of Lodging of the Consent Decree at the Whiting Refinery; provided that the new, modified or affected emissions units for which credits are being used: (1) is being constructed, modified or affected for purposes of compliance with Tier III Vehicle Emission and Fuel Standards; and (2) has a federally enforceable, non-Title V Permit (*i.e*, a permit issued pursuant to the State of Indiana's consolidated Title V construction and operating permit

program) that reflects the following requirements that are applicable to the pollutants for which credits are being used:

a. For heaters and boilers, a limit of 0.027 lbs. NOx per million BTU on a 3-hour rolling average basis;

b. For heaters and boilers, a limit of 0.10 grains of $H_2S$ per dry standard cubic foot of fuel gas or 20 ppmvd $SO_2$ corrected to 0% $O_2$ both on a 3-hour rolling average basis;

c. For heaters and boilers, no liquid or solid fuel firing authorization;

d. For FCCUs, a limit of 20 ppmvd NOx corrected to 0% $O_2$ on a 365-day rolling average basis;

e. For FCCUs, a limit of 25 ppmvd $SO_2$ corrected to 0% $O_2$ on a 365-day rolling average basis;

f. For FCCUs, a limit of 0.5 pounds of PM per 1,000 pounds of coke burned on a 3-hour average basis; and

g. For SRPs, a limit of 100 ppmvd $SO_2$ at 0% $O_2$ on a 24-hour rolling average basis.

86. Conditions Precedent to Utilizing Exception to General Prohibition. Utilization of the exception set forth in Paragraph 85 to the general prohibition against the generation or utilization of CD Emissions Reductions set forth in Paragraph 84 is subject to the following conditions:

a. Under no circumstances shall BPP use CD Emissions Reductions for netting and/or offsets prior to the time that actual CD Emissions Reductions have occurred;

b. CD Emissions Reductions may be used only at the Whiting Refinery;

c. The CD Emissions Reductions provisions of this Consent Decree are for purposes of this Consent Decree only and neither BPP nor any other entity may use CD Emissions Reductions for any purpose, including in any subsequent permitting or enforcement proceeding, except as provided herein; and

d. BPP still shall be subject to all federal, state and local regulations applicable to the PSD, major non-attainment and/or minor NSR permitting process.

87. Outside the Scope of the General Prohibition. Nothing in this Part is intended to prohibit BPP from seeking to, or IDEM from denying BPP's request to:

a. Utilize or generate emissions credits from refinery units that are covered by this Consent Decree to the extent that the proposed credits or reductions represent the difference between the emissions limitations set forth in or required by this Consent Decree for these refinery units and the more stringent emissions limitations that BPP may elect to accept for these refinery units in a permitting process; or

b. Utilize or generate emissions credits or reductions on refinery units that are not subject to an emission limitation pursuant to this Consent Decree; or

c. Utilize emissions reductions pursuant to this Consent Decree for the Whiting Refinery's compliance with any rules or regulations designed to address regional haze or the non-attainment status of any area (excluding PSD and Non-Attainment New Source Review Rules, but including, for example, RACT rules) that apply to the Whiting Refinery. Notwithstanding the preceding sentence, BPP will not trade or sell any emissions reductions that result from any projects conducted or controls utilized pursuant to this Consent Decree.

## VII. SUPPLEMENTAL ENVIRONMENTAL PROJECT AND ADDITIONAL INJUNCTIVE RELIEF

### A. Supplemental Environmental Project

88. BPP shall implement as a Supplemental Environmental Project ("SEP") a project to install monitors at the fenceline or perimeter of the Whiting Refinery to monitor certain emissions and make the data publicly available ("Fenceline Monitoring SEP"), as provided in Appendix E of this Consent Decree. BPP shall spend not less than $2 million to implement the Fenceline Monitoring SEP, the installation and

commencement of operation of which shall be completed by no later than 18 months after the Date of Entry.

89. BPP is responsible for the satisfactory completion of the Fenceline Monitoring SEP as provided in this Consent Decree. BPP may use contractors or consultants in planning and implementing the SEP.

a. If BPP does not expend the entire amount specified in Paragraph 88, BPP shall pay a stipulated penalty equal to the difference between the amount expended as demonstrated in the certified cost report and the amount specified in Paragraph 88. The stipulated penalty shall be paid as provided in Part X ("Stipulated Penalties") of this Consent Decree.

b. As an alternative to payment of such stipulated penalty, BPP may request approval from EPA to use unexpended SEP funds for an alternative SEP.

90. With regard to the Fenceline Monitoring SEP, BPP certifies the truth and accuracy of each of the following:

a. that all cost information provided to EPA in connection with the Fenceline Monitoring SEP is complete and accurate;

b. that, as of the date of executing this Consent Decree, BPP is not required to perform or develop the SEP by any federal, state, or local law or regulation and is not required to perform or develop the SEP by agreement, grant, or as injunctive relief awarded in any other action in any forum;

c. that the SEP is not a project that BPP was planning or intending to construct, perform, or implement other than in settlement of the claims resolved in this Consent Decree;

d. that BPP has not received and will not receive credit for the SEP in any other enforcement action;

e. that BPP will not receive any reimbursement for any portion of the SEP from any other person;

f. that BPP is not a party to any Open Federal Financial Assistance Transaction that is or could be used to fund the same activity as the SEP described in Appendix E; and

g. that based upon a reasonable inquiry:

i. the activity covered by this SEP has not been described in an unsuccessful Federal Financial Assistance Transaction proposal submitted by BPP to EPA within two years of the date of executing this Consent Decree (unless the project was barred from funding as statutorily ineligible); and

ii. BPP is not aware of any open Federal Financial Assistance Transaction that is funding or could fund the same activity as the SEP described in Appendix E.

91. BPP shall include in each report required by Paragraph 98.c of Part VIII ("Reporting and Recordkeeping") a description of its progress toward implementing the SEP required by this Section. In addition, the report required by Paragraph 98.c. for the period in which the SEP is completed shall contain the following information with respect to the SEP ("SEP Completion Report"):

a. a detailed description of the SEP as implemented;

b. a description of any problems encountered in completing the SEP and the solutions thereto;

c. an itemized list of all eligible SEP costs expended;

d. certification that the SEP has been fully implemented pursuant to the provisions of this Decree; and

e. a description of the environmental and public health benefits resulting from implementation of the SEP (with a quantification of the benefits and pollutant reductions, if feasible).

EPA may require information in addition to that described in this Paragraph, in order to evaluate BPP's SEP Completion Report.

92. Disputes concerning the satisfactory performance of this SEP and the amount of eligible SEP costs may be resolved under Part XIV of this Decree ("Dispute Resolution"). No other disputes arising under this Section shall be subject to Dispute Resolution.

93. BPP agrees that it must clearly indicate that the Fenceline Monitoring SEP is being or has been undertaken as part of the settlement of an action to enforce the Clean Air Act and corollary state statutes in any public statements regarding the project.

94. For federal income tax purposes, BPP agrees that it will neither capitalize into inventory or basis nor deduct any costs or expenditures incurred in performing the SEP.

**B. Additional Injunctive Relief**

95. Energy Efficiency and Greenhouse Gas ("GHG") Improvements.

a. Study: BPP certifies that it has retained KBC Advanced Technologies, Inc. ("KBC") to conduct an energy study for the Whiting Refinery consistent with the "KBC Whiting Energy Study Scope" description provided to Citizen-Intervenors on June 10, 2010. By no later than three (3) months after the Date of Entry of the Consent Decree, BPP shall provide Citizen-Intervenors a report on the results of that study. This report shall include:

i. A facility-wide assessment of fuel, steam, power, and other utility consumption;

ii. A comprehensive evaluation of potential opportunities to reduce fossil fuel usage, including solar-assisted boilers, flameless oxidation heater and boiler technology and other energy efficiency technologies and practices as may be identified by BPP or KBC;

iii. An estimate of GHG emissions from all units identified in the KBC Whiting Energy Study Scope, including all associated heaters, boilers, and flares; and

iv. A complete list of the potential GHG reduction projects identified by the KBC Whiting Energy Study Scope including:

(1) A tabulation of the estimated cost of each project;

(2) Potential savings in fuel, steam, power, and other utilities;

(3) Estimated GHG reductions of each project; and

(4) Estimated payback (if any).

b. Confidential Business Information ("CBI"). CBI may be redacted from the report. The following classes of information shall not be defined as CBI:

i. The data and the calculation methodologies used to estimate GHG emissions and potential reductions;

ii. The costs and payback period of potential GHG projects and the underlying assumptions used to determine costs and benefits;

iii. The estimated savings in fuel, steam, power, or other utilities of potential GHG projects; and

iv. The projects selected by BPP to satisfy its commitments under this Section.

c. Project Selection Report. By no later than six (6) months after the Date of Entry of the Consent Decree, BPP shall submit a report to Citizen-Intervenors identifying each of the GHG projects that BPP plans to undertake and the anticipated timeline for completion of each project. The projects BPP identifies shall have an estimated cost of at least $9.5 million, and shall not include expenditures on audits, studies, or recommendations required under Paragraph 95.a. BPP will use good faith efforts to select projects that maximize the potential for GHG reductions, taking into account cost effectiveness, safety, operability and relevant permitting requirements.

d. Limitations. No improvements otherwise required by this Consent Decree, state, or federal regulation shall constitute a qualifying energy efficiency or GHG improvement for the purposes of this Paragraph.

e. Timeline. By no later than five (5) years after the Date of Entry of the Consent Decree, BPP shall:

i. Spend no less than $9.5 million to complete the GHG reduction projects identified in subparagraph b of this Paragraph; and

ii. Provide Citizen-Intervenors with a report documenting:

(1) The GHG projects chosen;

(2) The cost of the projects chosen;

(3) Reductions in GHG emissions achieved by each project; and

(4) The savings in fuel, steam, power, or utilities related to the GHG reduction projects.

f. Permits. BPP shall comply with all applicable Federal, state, and local permitting requirements for such projects.

96. BPP shall provide copies of any reports or other submissions required by Paragraph 95 to EPA.

## VIII. REPORTING AND RECORDKEEPING

97. BPP shall retain all records required to be maintained in accordance with this Consent Decree for a period of five (5) years or until Termination, whichever is longer, unless applicable regulations require the records to be maintained longer.

98. On or before February 15 and August 15 each year, BPP shall submit to EPA and IDEM a semi-annual report as provided in this Part. Each semi-annual report shall contain the following information for the previous six month period (*i.e.*, January to June to be addressed in the report to be submitted by August 15, and July to December to be addressed in the report submitted by February 15):

a. For the period covered by the report, a summary of the emissions data for the Whiting Refinery that is specifically required by the reporting requirements of the Consent Decree for the period covered by the report;

b. A description of any problems that have occurred or are anticipated with respect to meeting the requirements of this Consent Decree at the Whiting Refinery;

c. A description of the Supplemental Environmental Project and implementation activity in accordance with this Consent Decree;

d. The information specified in Paragraph 72 of Appendix D ("Monitoring Instrument/Equipment Downtime; Override of ACS; and Emissions Exceedances");

e. Any additional matters as BPP believes should be brought to the attention of EPA and IDEM; and

f. Any additional items required by any other Paragraph of this Consent Decree to be submitted with a semi-annual report.

99. Emissions Data. In the semi-annual report required by this Part VIII of the Consent Decree to be submitted by August 15 of each calendar year, BPP shall

provide a summary of annual emissions data for the Whiting Refinery for the prior calendar year, to include:

a. NOx emissions in tons per year for each heater and boiler greater than 40 mmBTU/hr maximum fired duty;

b. NOx emissions in tons per year as a sum for all heaters and boilers less than 40 mmBTU/hr maximum fired duty;

c. $SO_2$, CO and PM emissions in tons per year as a sum for all heaters and boilers;

d. $SO_2$ emissions from the Sulfur Recovery Plant in tons per year;

e. $SO_2$ emissions from all Acid Gas Flaring and Tail Gas Incidents by flare in tons per year;

f. NOx, $SO_2$, PM and CO emissions in tons per year as a sum for all other emissions units for which emissions information is required to be included in the facilities' annual emissions summaries and that are not identified above; and

g. NOx, $SO_2$, CO and PM emissions in tons per year for each FCCU; and

h. Emissions from Covered Flares and the LPG Flare as specified in Paragraph 73 of Appendix D.

i. For each of the estimates or calculations in Subparagraphs 99.a through 99.h above, the basis for the emissions estimate or calculation (*i.e.*, stack tests, CEMS, emission factor, etc.).

To the extent that the required emissions summary data are available in other reports generated by BPP, such other reports can be attached or the appropriate information can be extracted from such other reports and attached to the report to satisfy the requirement.

100. Exceedances of Emission Limits and CEMS Downtime: In each semi-annual report required by Part VIII of the Consent Decree, BPP will provide a summary of all exceedances of emission limits required or established by this Consent Decree, which will include the following:

a. For operating unit emissions limits that are required by this Consent Decree and monitored with CEMS, for each CEMS:

i. Total period when the emissions limit was exceeded, if applicable, expressed as a percentage of operating time for each calendar quarter;

ii. Where the operating unit has exceeded the emissions limit more than 1% of the total time of the calendar quarter, identification of each averaging period that exceeded the limit by time and date, the actual emissions of that averaging period (in the units of the limit), and any identified cause for the exceedance (including Startup, Shutdown, maintenance or Malfunction), and, if it was a malfunction, an explanation and any corrective actions taken;

iii. Total downtime of the CEMS, if applicable, expressed as a percentage of operating time for the calendar quarter;

iv. Where the CEMS downtime is greater than 5% of the total time in a calendar quarter for a unit, identify the periods of downtime by time and date, any cause of the downtime (including maintenance or malfunction), and, if it was a malfunction, an explanation and any corrective action taken.

v. If a report filed pursuant to another applicable legal requirement contains all of the information required by Paragraph 100.a.i-iv above in similar or the same format, the requirements of Paragraph 100.a.i-iv above may be satisfied by attaching a copy of such report.

b. For any exceedance of an emissions limit required by this Consent Decree from an operating unit monitored through stack testing:

i. A summary of the results of the stack test in which the exceedance occurred; and

ii. A copy of the full stack test report in which the exceedance occurred.

iii. To the extent that a refinery has already submitted the stack test results to the EPA and IDEM, BPP need not resubmit them, but may instead reference the submission in the report (*e.g.*, date, addressee, reason for submission).

101. FCCU Reporting and Recordkeeping Requirements.

a. BPP shall include in each semi-annual report required by this Part VIII the results of all testing of FCU 500 and FCU 600 required by Paragraph 21 ("FCCU Performance Testing"). The performance test reports shall include all relevant testing data and information, including, but not limited to the following: PM, $PM_{10}$, $PM_{TOTAL}$, $SO_2$ concentration, NOx concentration, catalyst additive rates, ammonia addition prior to ESP, ammonia addition at the SCR, ammonia slip, the average total power and secondary current to the entire ESP system, the coke burn-off rate, regenerator overhead temperature, and the FCCU feed rate.

b. BPP shall include in each semi-annual report copies of all applicable reports required by 40 C.F.R. § 60.108a for the previous 6-month period.

c. Concurrent with submission to EPA, BPP shall submit copies to Citizen-Intervenors of all reports of emissions testing required by this Paragraph. BPP may redact from the reports submitted to Citizen-Intervenors any information meeting the requirements for Confidential Business Information ("CBI") pursuant to 40 C.F.R. Part 2, Subpart B, except that the data (including the operating parameters identified in Paragraph 21.a) and the calculation methodologies used to estimate emissions shall not be redacted as CBI.

102. Each report will be certified for BPP by an officer of BPP responsible for overseeing implementation of this Consent Decree, as follows:

> "I certify under penalty of law that this information was prepared under my direction or supervision by personnel qualified to properly gather and evaluate the information submitted. Based on my directions and after reasonable inquiry of the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate and complete."

## IX. CIVIL PENALTY

103. Within 30 Days after the Date of Entry of this Consent Decree, BPP shall pay the sum of $7,200,000 as a civil penalty to the United States and the sum of $800,000 as a civil penalty to the State of Indiana in accordance with the following:

a. Payment to the United States. BPP shall pay the civil penalty due by FedWire Electronic Funds Transfer ("EFT") to the U.S. Department of Justice in accordance with written instructions to be provided to Defendant, following entry of the Consent Decree, by the Financial Litigation Unit of the U.S. Attorney's Office for the Northern District of Indiana, 5400 Federal Plaza, Suite 1500, Hammond, In. 46320. At the time of payment, BPP shall send a copy of the EFT authorization form and the EFT transaction record, together with a transmittal letter, which shall state that the payment is for the civil penalty owed pursuant to the Consent Decree in *United States, et al. v. BP Products North America Inc.*, and shall reference the civil action number and DOJ case number 90-5-2-1-09244, to the United States in accordance with Part XIV of this Decree ("Notices"); by email to acctsreceivable.CINWD@epa.gov; and by mail to:

EPA Cincinnati Finance Office
26 Martin Luther King Drive
Cincinnati, Ohio 45268

b. Payment to the State of Indiana. Payment to Indiana shall be made by certified check or checks or cashier's checks made payable to ""Environmental Management Special Fund" referencing the name and address of the party making payment, and the civil action number. BPP shall send the check(s) to:

Indiana Department of Environmental Management
Cashier - MC 50-10C
100 North Senate Avenue
Indianapolis, IN 46204-2251

104. The civil penalty set forth herein, as well as any stipulated penalty incurred pursuant to Part X ("Stipulated Penalties"), is a penalty within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and, therefore, BPP will not treat such penalty payment as tax deductible for purposes of federal or state law.

105. Upon the Date of Entry, this Consent Decree will constitute an enforceable judgment for purposes of post-judgment collection in accordance with Rule 69 of the Federal Rules of Civil Procedure, the Federal Debt Collection Procedures Act, 28 U.S.C. § 3001, *et seq.*, and other applicable federal authority. The United States will

be deemed a judgment creditor for purposes of collecting any unpaid amounts of the penalty and interest pursuant to this Part, or any stipulated penalty owed pursuant to Part X ("Stipulated Penalties").

## X. STIPULATED PENALTIES

106. Stipulated penalties shall be paid to the United States and to Indiana as provided herein for each failure by BPP to comply with the terms of this Consent Decree. In no event shall any stipulated penalty assessed exceed $37,500 per day for any individual violation of this Consent Decree. Stipulated penalties shall be calculated in the amounts specified in this Part X. For those provisions where a stipulated penalty of either a fixed amount or 1.2 times the economic benefit of delayed compliance is available, the decision of which alternative to seek shall rest exclusively within the discretion of the United States.

A. Requirements for NOx Emissions Reductions from FCCUs

107. For failure to meet any emissions limit for NOx set forth in Paragraph 12, per day, per unit: $2500 for each calendar day on which the specified 7-day or 365-day rolling average exceeds the applicable limit.

108. For failure to install, certify, calibrate, maintain, and/or operate a NOx CEMS as required by Paragraph 13, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1000 |
| Beyond 60th day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

B. Requirements for $SO_2$ Emissions Reductions from FCCUs.

109. For each failure to meet any $SO_2$ emission limit set forth in Paragraph 15, per unit, per day: $3000 for each calendar day on which the specified 7-day or 365-day average exceeds the applicable limit.

110. For failure to install, certify, calibrate, maintain, and/or operate a $SO_2$ CEMS as required by Paragraph 16, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1000 |
| Beyond 60th day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

C. Requirements for Particulate Matter Emissions Reductions from FCCUs

111. For failure to conduct PM testing, as required by Paragraphs 17 and 21, per day, per test, per FCCU:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $200 |
| 31st through 60th day after deadline | $500 |
| Beyond 60th day after deadline | $1000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

112. For each failure to meet any applicable PM emission limit for FCCUs as set forth in Paragraph 18, per day, per unit: $750 for each calendar day on which the emission limit is exceeded.

113. For each failure to monitor and/or record any supplemental monitoring as set forth in Paragraph 19: $250 per day.

D. Requirements for CO Emissions Reductions from FCCUs

114. For each failure to meet the applicable CO emission limits for FCCUs as set forth in Paragraphs 24-25: $2500 for each calendar day on which the specified 1-hour rolling average exceeds the applicable limit.

115. For failure to install, certify, calibrate, maintain, and/or operate a CO CEMS as required by Paragraph 27, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1000 |
| Beyond 60th day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

E. Requirements for VOC Emissions Reductions from FCCUs

116. For each failure to meet the applicable VOC emission limits for FCCUs as set forth in Paragraphs 28-29: $750 for each calendar day on which the applicable limit is exceeded.

117. For failure to conduct VOC stack testing, as required by Paragraph 30, per day, per test, per FCCU:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $200 |
| 31st through 60th day after deadline | $500 |
| Beyond 60th day after deadline | $1000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

F. Requirements for NOx Emissions Reductions from Heaters and Boilers

118. For failure to install required control technologies by the dates specified in Paragraph 31.b and 34.a:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $1500 |
| 31st through 60th day after deadline | $2000 |
| Beyond 60th day after deadline | $3000 |

119. For failure to install, certify, calibrate, maintain, and/or operate a NOx CEMS as required by Paragraphs 32, 35.b and 36, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1$^{st}$ through 30$^{th}$ day after deadline | $500 |
| 31$^{st}$ through 60$^{th}$ day after deadline | $1000 |
| Beyond 60$^{th}$ day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

120. For failure to comply with an applicable emission limit at a heater or boiler listed in Paragraphs 31.b and 34.a, or failure to comply with the NSPS Subparts A and Ja emission limits at a heater or boiler as specified in Paragraph 33, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1$^{st}$ through 30$^{th}$ day after deadline | $500 |
| 31$^{st}$ through 60$^{th}$ day after deadline | $1000 |
| Beyond 60$^{th}$ day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

121. For failure to conduct NOx testing, as required by Paragraph 35.a, per day, per test, per unit:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1$^{st}$ through 30$^{th}$ day after deadline | $200 |
| 31$^{st}$ through 60$^{th}$ day after deadline | $500 |
| Beyond 60$^{th}$ day after deadline | $1000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

G. Requirements for $SO_2$ Emissions Reductions from Heaters and Boilers

122. For failure to comply with an applicable emission limit or monitoring requirement of NSPS Subparts A and Ja at a heater or boiler as specified in Paragraph 39, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1000 |
| Beyond 60th day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

123. For burning Fuel Oil in a manner inconsistent with the requirements of Paragraph 40, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $1750 |
| Beyond 30th day after deadline | $5000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

H. Requirements for Fuel Gas Sulfur Content

124. For failure to install, certify, calibrate, maintain, and/or operate a Total Sulfur Continuous Analyzer as required by Paragraph 41, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1000 |
| Beyond 60th day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

125. For failure to comply with total sulfur emission limit as specified in Paragraph 41, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1000 |
| Beyond 60th day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

I. Requirements for CEM Downtime Minimization, O&M and Corrective Action

126. For failure to develop and/or submit the CEMS O&M Plan required by Paragraph 43, and for failure to include CEMS Testing and Calibration requirements in the CEMS O&M Plan as required by Paragraph 45:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $200 |
| 31st through 60th day after deadline | $500 |
| Beyond 60th day after deadline | $1000 |

127. For failure to develop or implement the CEMS O&M training programs specified in Paragraph 44: $10,000.

128. For failure to develop or implement a Preventive Maintenance and Repair, and QA/QC program as specified in Paragraph 46:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1500 |
| Beyond 60th day after deadline | $2000 |

129. For failure to conduct a CEMS Root Cause Failure Analysis required by Paragraph 48: $5,000 per month, per analysis.

130. For failure to implement any actions necessary to correct non-compliance as required by Paragraph 49:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $1250 |
| 31st through 60th day after deadline | $3000 |
| Beyond 60th day after deadline | $5000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

J. Requirements for Benzene Waste NESHAP

131. For failure to comply with the 6 BQ Option required by Paragraph 50.a and 50.b: $30,000 for each 0.6 Mg (10%) increment by which the 6 BQ Option uncontrolled benzene limit is exceeded, up to $1.5 million per year that the limit is exceeded.

132. For failure to comply with the Organic Benzene Waste control requirements of Paragraph 50.c: $12,500 per month per uncontrolled waste management unit.

133. For failure to install and/or operate carbon canisters as required by Paragraph 52: $1,000 per day, per carbon canister.

134. For failure to establish an annual review program to identify new benzene waste streams as required by Paragraph 53: $2,500 per month.

135. For failure to perform laboratory audits as required by Paragraph 54: $5,000 per month, per audit.

136. For failure to implement the training requirements as set forth in Paragraph 56: $10,000 per quarter.

137. For failure to maintain or submit any plan, report or other deliverable required by Paragraphs 57, 58, 61 or 62: $5,000 per month.

138. For failure to conduct monthly visual inspections of all water traps as required by Paragraph 60.a, and for failure to inspect each drain system as required by Paragraph 60.c: $500 per drain or drain system not inspected.

139. For failure to identify/mark segregated storm water drains as required in Paragraph 60.b: $1,000 per week, per drain.

140. For failure to monitor conservation vents as required by Paragraph 60.d: $500 per vent not monitored.

141. If it is determined through federal, state, or local investigation that BPP has failed to include all benzene waste streams in its TAB calculation submitted pursuant to Section J., BPP shall pay the following, per waste stream:

| Waste Stream | Penalty |
|---|---|
| For waste streams < 0.03 Mg/yr | $250 |
| For waste streams between 0.03 and 0.1 Mg/yr | $1000 |
| For waste streams between 0.1 and 0.5 Mg/yr | $5000 |
| For waste streams > 0.5 Mg/yr | $10,000 |

142. For failure to complete construction of a new DAF unit by the date specified in Paragraph 60.g, or to route emissions from the DAF unit and API Separator as required by Paragraph 60.g:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $1250 |
| 31st through 60th day after deadline | $3000 |
| Beyond 60th day after deadline | $5000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

143. For failure to perform any requirement of a Root Cause Failure Analysis or Corrective Action required by Paragraph 62.a.iii: $2,500 per week, per requirement.

K. Requirements for Leak Detection and Repair Program Enhancements

144. The following stipulated penalties shall accrue per violation per day unless otherwise specified below, for each violation of a requirement of the ELP as set

forth in Part V, Section K of this Consent Decree ("Leak Detection and Repair") and Appendix B ("Enhanced LDAR Program") as specified below:

a. Failure to timely develop and complete a written facility-wide LDAR Program Plan, or to timely update the LDAR Program Plan, as required by Paragraph 3:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 15th day after deadline | $300 |
| 16th through 30th day after deadline | $400 |
| Beyond 30th day after deadline | $500 |

b. Failure to timely perform monitoring at the frequencies set forth in Paragraph 4 or 5: $100 per component per day, but no more than $25,000 per month.

c. Failure to comply with Method 21 (or the AWP, as applicable) in performing LDAR monitoring, as indicated by the leak percentage ratio calculated under Paragraph 29.c. of the ELP (Appendix B), but only if the auditor identifies a leak rate of at least 0.5% per component type in the process unit:

| Comparative Monitoring Leak Ratio As Determined Under ¶29.c. of the ELP | Penalty per Process Unit |
|---|---|
| 3.0 or greater but less than 4.0 | $15,000 |
| 4.0 or greater but less than 5.0 | $30,000 |
| 5.0 or greater but less than 6.0 | $45,000 |
| 6.0 or greater | $60,000 |

d. Failure to use a monitoring device that is attached to a data logger; failure, during each monitoring event, to directly electronically record the Screening Value, date, time, identification number of the monitoring equipment, or the identification of the technician, as required by Paragraph 6: $100 per failure per piece of Covered Equipment, but not greater than $5,000 per unit per month.

e. Failure to transfer monitoring data to an electronic database on at least a weekly basis, as required by Paragraph 6: $150 per day for each day that the transfer is late.

f. Failure to timely perform a first attempt at repair, as required by Paragraph 11 or 12. For purposes of this subparagraph, the term "repair" includes the required repair verification monitoring in Paragraph 13 after the first repair attempt (in which case the stipulated penalties of Paragraph 144.h do not apply): \$150 per day for each day after deadline, not to exceed \$1500 per leak.

g. Failure to timely perform a final attempt at repair, as required by Paragraph 12. For purposes of this subparagraph, the term "repair" includes the required repair verification monitoring in Paragraph 13 after the first repair attempt (in which case the stipulated penalties of Paragraph 144.h do not apply):

| Equipment Type | Penalty per Day, Per Component | Not to Exceed |
|---|---|---|
| Valves, connectors | \$300 | \$37,500 |
| Pumps, agitators | \$1200 | \$150,000 |

h. Failure to timely perform Repair Verification Monitoring, as required by Paragraph 13, where the first attempt to repair was made to within 5 days and the final attempt to repair was made within 15 days:

| Equipment Type | Penalty per Day, Per Component | Not to Exceed |
|---|---|---|
| Valves, connectors | \$150 | \$18,750 |
| Pumps, agitators | \$600 | \$75,000 |

i. Failure to undertake drill-and-tap repairs, as required by Paragraph 14:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 15th day after deadline | \$200 |
| 16th through 30th day after deadline | \$350 |
| Beyond 30th day after deadline | \$500, not to exceed \$37,500 |

j. Failure to record the information required by Paragraph 15: \$100 per component, per item of missed information.

k. Improperly placing a piece of Covered Equipment on the DOR list (*i.e.*, placing a piece of Covered Equipment on the DOR list even though it is feasible to repair without a process unit shutdown), as required by Paragraph 17:

| Equipment Type | Penalty per Day, Per Component | Not to Exceed |
|---|---|---|
| Valves, connectors | $300 | $75,000 |
| Pumps, agitators | $1200 | $300,000 |

l. Failure of the relevant manager or official to sign-off on placing a piece of Covered Equipment on the DOR list, as required by Paragraph 17.a: $250 per piece of Covered Equipment.

m. Failure to comply with the 0.10% limit on valves that may be placed on the DOR list, as required by Paragraph 17.c: $5,000 per valve.

n. Failure to install a Certified Low-Leaking Valve or to fit a valve with Certified Low-Leaking Valve Packing, as required by Paragraph 19: $1000 per valve required by Paragraph 19.c and $5,000 per valve required by Paragraph 19.d.

o. Failure to add a piece of Covered Equipment to the LDAR program, as required by Paragraph 23: $300 per piece of Covered Equipment (plus an amount, if any, due under Paragraph 144.b for any missed monitoring for a component that should have been added to the LDAR program).

p. Failure to remove a piece of Covered Equipment from the LDAR program, as required by Paragraph 23: $150 per piece of Covered Equipment.

q. Failure to timely develop a training protocol, as required by Paragraph 24: $50 per day of noncompliance.

r. Failure to perform initial, refresher, or new personnel training, as required by Paragraph 24: $1000 per person, per month of noncompliance.

s. Failure of a monitoring technician to complete the certification required by Paragraph 25: $100 per failure, per technician.

t. Failure to perform any of the requirements of Paragraph 26: $1000 per missed requirement, per year.

u. Failure to conduct an LDAR audit in accordance with the schedule set forth in Paragraph 28:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| $1^{st}$ through $15^{th}$ day after deadline | $300 |
| $16^{th}$ through $30^{th}$ day after deadline | $400 |
| Beyond $30^{th}$ day after deadline | $500, not to exceed $100,000 per audit |

v. Failure to use a third-party auditor, or to use a third-party auditor that is not experienced in LDAR audits, as required by Paragraph 28: $25,000 per audit.

w. Failure to comply with the requirements in Paragraph 29 except for Paragraphs 29.a-c: $10,000 per missed requirement, not to exceed $100,000 per audit.

x. Failure to comply with the requirements of Paragraphs 29.a-c: $50,000 per audit.

y. Failure to timely develop and/or submit a Corrective Action Plan, as required by Paragraph 31:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| $1^{st}$ through $15^{th}$ day after deadline | $100 |
| $16^{th}$ through $30^{th}$ day after deadline | $250 |
| Beyond $30^{th}$ day after deadline | $500, not to exceed $100,000 per audit |

z. Failure to implement corrective action within 90 days after the LDAR Audit Completion Date, or pursuant to the approved schedule, as required by Paragraph 31:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| $1^{st}$ through $15^{th}$ day after deadline | $500 |
| $16^{th}$ through $30^{th}$ day after deadline | $750 |
| Beyond $30^{th}$ day after deadline | $1000, not to exceed $200,000 per audit |

aa. Failure to timely submit a Certification of Compliance, as required by Paragraph 32:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 15th day after deadline | $100 |
| 16th through 30th day after deadline | $250 |
| Beyond 30th day after deadline | $500, not to exceed $100,000 per audit |

bb. Failure to secure and retain documentation required pursuant to Paragraph 21: $1000 per valve or packing type.

L. Requirements for Sulfur Recovery Plant and Sulfur Pits

145. For failure to comply with the NSPS Subparts A and Ja emission limits for SRPs (as required by Paragraph 65) or sulfur pits (as required by Paragraph 69.a), or with the SRP emission limit (as required by Paragraph 66), or to control emissions from drums and tanks (as required by Paragraph 69.b), per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $1000 |
| 31st through 60th day after deadline | $2000 |
| Beyond 60th day after deadline | $3000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

146. For failure to operate and maintain control and monitoring equipment as required by Paragraph 69.a, per unit, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $1000 |
| 31st through 60th day after deadline | $2000 |
| Beyond 60th day after deadline | $3000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

147. For failure to route all sulfur pit emissions in accordance with the requirements of Paragraph 69.c.i:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $2000 |
| 31st through 60th day after deadline | $3500 |
| Beyond 60th day after deadline | $5000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

M. Requirements for Certain Tanks

148. a. For failure to install or operate the control equipment in accordance with the requirements of Paragraphs 70 through 74, or to timely repair leaks identified through the Optical Gas Imaging Camera Monitoring as required by Paragraph 75, per day, per unit:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1500 |
| Beyond 60th day after deadline | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

b. For failure to conduct sampling or monitoring as required by Paragraphs 70 through 75:

| | |
|---|---|
| Daily sampling or monitoring: | $500 per missed sampling or monitoring event |
| Monthly and Annual monitoring or sampling: | $1000 per missed sampling or monitoring event, plus $500 for each additional day after deadline up until the next required monitoring event |

c. For failure to keep records as required by Paragraphs 70 through 75: $500 per missing daily sampling or monitoring record; $1000 per missing monthly or annual sampling or monitoring record.

d. For failure to meet emission limits set forth in Paragraphs 73 and 74: $5000 per month of violation.

N. Requirements for VOC, PM, TRS, and $H_2S$ Emissions Reductions from the Whiting Refinery New Coker

149. For failure to comply with the depressurization level for the coker (as specified by Paragraph 77), the coke drum parameters (as specified by Paragraph 78), the Quench Water System or Operating Practices (as specified by Paragraphs 79 and 80), or the coke pit requirements (as specified by Paragraph 81), per requirement, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $1000 |
| 31st through 60th day after deadline | $2000 |
| Beyond 60th day after deadline | $3000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

O. Requirements for Flaring Devices

150. The following stipulated penalties shall apply to violations of requirements set forth in Appendix D "(Emission Reductions From Flares and Flaring Devices") as specified below:

a. Violation of Paragraph 1.a or 1.b. Failure to timely install a system that complies with the requirements of Paragraph 1.a or failure to timely complete operator and supervisor training that conforms to the requirements of Paragraph 1.b:

| Period of Delay or Non-Compliance (per Flare, for Paragraph 1.a) | Penalty per Day |
|---|---|
| Days 1-30 | $500 |
| Days 31-60 | $1500 |
| Days 61 and later | $2500 |

b. Violation of Paragraph 1.c. For the time period between 90 days after Date of Entry and the compliance date in Paragraph 34.a, failure to minimize the S/VG ratio to the extent practical with the existing monitoring and instrumentation: Penalty per Flare per day or fraction thereof: $1500.

c. Violation of Paragraph 2 or 3. Failure to timely upgrade or replace, as necessary, Sweep and Purge Gas flow meters that conform to the requirements of Paragraph 2 or failure to timely implement the measures necessary to minimize Sweep and Purge Gas flow:

| Period of Delay or Non-Compliance (per meter, for Paragraph 2) | Penalty per Day |
|---|---|
| Days 1-30 | $250 |
| Days 31-60 | $500 |
| Days 61 and later | $1250 |

d. Violation of Survey Requirements of Paragraph 4. Failure to timely complete the Initial PRV Leak Survey required in Paragraph 4:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| Days 1-30 | $250 |
| Days 31-60 | $500 |
| Days 61 and later | $1250 |

e. Violation of Repair Requirements of Paragraph 4. Failure to timely repair each leaking PRV:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| Days 1-30 | $500 |
| Days 31-60 | $700 |
| Days 61 and later | $1000 |

f. (i) Violation of Paragraph 5. Failure to timely submit a report as required by Paragraph 5:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| Days 1-30 | $300 |
| Days 31-60 | $400 |
| Days 61 and later | $500 |

(ii) Violation of Paragraph 5. Failure to submit a report that conforms to the requirements of Paragraph 5: $50,000 per report.

g. (i) Violation of Paragraphs 18, 19, or 20. Failure to timely submit a plan as required by those Paragraphs:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| Days 1-30 | $500 |
| Days 31-60 | $750 |
| Days 61 and later | $1000 |

(ii) Violation of Paragraphs 18, 19, or 20. Failure to submit a plan that conforms to the requirements of those Paragraphs: Paragraph 18: $100,000 per plan; Paragraphs 19 and 20: $50,000 per plan.

h. Violation of Paragraph 6, 7, 8, 9, 10, 11, 12, 13, 15, 16, or 42. Failure to timely install the equipment and monitoring systems required by Paragraphs 7-13 and 42 in accordance with the respective, applicable technical specifications in those Paragraphs, Paragraph 16, and Appendix FLR-11 (except for the requirements of Appendix FLR-11 found in Subparagraphs I.g, III.e, IV, V.B, and VI.a; those are QA/QC requirements covered in Subparagraph 150.i below):

| Period of Delay or Non-Compliance, per monitoring system | Penalty per Day per monitoring system |
|---|---|
| Days 1-30 | $750 |
| Days 31-60 | $1250 |
| Days 61 and later | $2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

i. Violation of the QA/QC requirements in Appendix FLR-11. Failure to comply with the QA/QC requirements in Appendix FLR-11 at Paragraphs I.g, III.e, IV, V.B, or VI.a:

| Violation of a: | Penalty |
|---|---|
| Daily requirement | $100 |
| Quarterly requirement | $200 per day late |
| Annual requirement | $500 per day late |

j. Violation of Paragraph 17. Except for 110 hours per calendar quarter, failure to operate the monitoring instrument in Paragraphs 7-9, 11-13, 42.a. or 42.b:

| Per monitoring instrument, Number of Hours per Calendar Quarter of Downtime over 110 | Penalty per Hour per monitoring instrument |
|---|---|
| 0.25-50.0 | $250 |
| 50.25-100.0 | $500 |
| Over 100.0 | $1000 |

k. Violation of Paragraph 23, 24, or 25.a. Failure to timely install, in accordance with Paragraph 23, a Flare Gas Recovery System that conforms to the requirements of Paragraph 24, or failure to timely equip, in accordance with Paragraph 25.a, automatic startup capability on each FGRS:

| Period of Delay or noncompliance, per FGRS | Penalty per Day per FGRS |
|---|---|
| Days 1-30 | $1250 |
| Days 31-60 | $3000 |
| Days 61 and later | $5000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater |

l. Violation of Paragraph 25.b. Failure to have the required number of compressors at each FGRS available for operation at least 95% of the time in a rolling 8760-hour rolling average period:

Per FGRS, the number of hours or fraction thereof – over 438 – in a rolling 8760-hour period that a compressor required to be available for operation is not: $750

m. Violation of Paragraph 25.c. Failure to comply with the requirements of Paragraphs 25.c.i or 25.c.ii: Per FGRS, per hour or fraction thereof of noncompliance: $750

n. Violation of Subparagraph 26.a (or any subsequent 30-day limit set pursuant to Paragraph 27.a.i). Failure to comply with the refinery-wide, 30-day rolling average limit on waste gas flaring

| Magnitude of Exceedance | Penalty per Day |
|---|---|
| ≤ 10% | $6250 |
| >10% to ≤ 20% | $12,500 |
| >20% | $18,750 |

o. Violation of Subparagraph 26.b (or any subsequent 365-day limit set pursuant to Paragraph 27.a.ii). Failure to comply with the refinery-wide 365-day rolling average limit on waste gas flaring:

| Magnitude of Exceedance | Penalty per Day |
|---|---|
| ≤ 10% | $12,500 |
| >10% to ≤ 20% | $18,750 |
| >20% | $37,500 |

p. Violation of Paragraph 30 or 42.c. Failure to timely comply with the requirements of Paragraph 30 (for the Covered Flares) or Paragraph 42.c (for the LPG Flare): Penalty per Flare per day: $500.

q. Violation of Paragraph 33.b – Covered Flares except DDU Flare. For each Covered Flare except the DDU Flare, failure to comply with the Net Heating Value in the Combustion Zone Gas ($NHV_{cz}$)standard in Paragraph 33.b:

| On a per Covered Flare basis, Hours per Calendar Quarter in Noncompliance | Penalty per Hour or fraction thereof per Covered Flare |
|---|---|
| Hours 0.25-50.0 | $150 |
| Hours 50.25-100.0 | $350 |
| Hours over 100 | $500 |

For purposes of calculating the number of hours of noncompliance with the NHV standard, all 15-minute periods of violation shall be added together to determine the total.

r. <u>Violation of Paragraph 33.b – DDU Flare</u>. For the DDU Flare, failure to comply with the Net Heating Value in the Combustion Zone Gas ($NHV_{cz}$) standard in Paragraph 33.b:

| Hours per calendar basis, Hours per <u>Calendar Quarter in Noncompliance</u> | Penalty per Hour or fraction <u>thereof per Covered Flare</u> |
|---|---|
| Hours 0.25-50.0 | $25 |
| Hours 50.25-100.0 | $75 |
| Hours over 100.0 | $150 |

s. <u>Violations of Paragraphs 45, 48.d, or 49.b.</u> For the LPG Flare, failure to comply with the $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ standard in Paragraph 45, 48.d, or 49.b, as applicable:

| Hours per calendar basis, Hours per <u>Calendar Quarter in Noncompliance</u> | Penalty per Hour or fraction <u>thereof per Covered Flare</u> |
|---|---|
| Hours 0.25-50.0 | $100 |
| Hours 50.25-100.0 | $200 |
| Hours over 100.0 | $300 |

For purposes of calculating the number of hours of noncompliance with the $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ standard, all five minute periods of violation shall be added together to determine the total.

t. <u>Violation of Subparagraph 35.b</u>. Failure to comply with the prohibition on Discontinuous Wake Dominated Flow:

| <u>Flare Tip Size (inches)</u> | Penalty per Hour or fraction <u>thereof</u> |
|---|---|
| 1.0-24.0 | $150 |
| 24.1-48.0 | $225 |
| Over 48.0 | $525 |

u. Violation of Subparagraph 35.c. Failure to comply with the applicable MFR standard:

| Flare Tip Size (inches) | Penalty per Hour or fraction thereof |
|---|---|
| 1.0-24.0 | $50 |
| 24.1-48.0 | $75 |
| Over 48.0 | $175 |

For purposes of calculating the number of hours of noncompliance with the MFR limit, all 5-minute periods of violation shall be added together to determine the total.

v. Violation of Paragraph 38 or 48.a. Failure to timely conduct the testing set forth in Paragraph 38 or 48.a (if required) in accordance with the protocol:

| For each flare test, Period of Delay or Noncompliance | Penalty per Day |
|---|---|
| Days 1-30 | $250 |
| Days 31-60 | $500 |
| Days 61 and later | $1000 |

w. (i) Violation of Paragraph 38, 39, or 48.b. Failure to timely submit a test protocol as required by Paragraph 38 or failure to timely submit a test report as required by Paragraph 39 or 48.b:

| For each flare test, Period of Delay or Noncompliance | Penalty per Day |
|---|---|
| Days 1-30 | $200 |
| Days 31-60 | $300 |
| Days 61 and later | $400 |

(ii) Violation of Paragraph 38, 39, or 48.b. Failure to submit a test protocol that conforms to the requirements of Paragraph 38, or failure to submit a test report that conforms to the requirements of Paragraph 30 or 48.b: $50,000 per protocol or report.

x. Violation of Paragraph 41. Failure to record any information required to be recorded pursuant to Paragraphs 41.a, b, c, or d: $100 per day.

y. Violation of Paragraph 54. Failure to timely develop a report that conforms to the requirements in Paragraph 54 or failure to keep it as an internal record:

| Period of Delay or Noncompliance | Penalty per Day |
|---|---|
| Days 1-30 | $800 |
| Days 31-60 | $1600 |
| Days 61 and later | $3000 |

z. Violation of Paragraph 55. For those corrective action(s) which BPP: (i) agrees to undertake following receipt of an objection by EPA pursuant to Paragraph 55.c; or (ii) is required to undertake following dispute resolution, then, from the date that either: (i) a final agreement is reached between EPA and BPP regarding the corrective action; or (ii) a court order regarding the corrective action is entered, BPP shall be liable for stipulated penalties:

| Period of Delay or Noncompliance | Penalty per Day |
|---|---|
| Days 1-120 | $50 |
| Days 121-180 | $100 |
| Days 181-365 | $300 |
| Days over 365 | $3000 or 1.2 times the economic benefit resulting from BPP's failure to implement the corrective action(s). |

The decision of whether to demand as a stipulated penalty the "per day" amounts or the economic benefit amount shall rest exclusively within the discretion of the United States.

aa. Violation of Paragraph 55. Failure to complete any corrective action under Paragraph 55.a in accordance with the schedule for corrective action agreed to by BPP (with any such extensions thereto as to which EPA and BPP may agree in writing):

| Period of Delay or Noncompliance | Penalty per Day |
|---|---|
| Days 1-30 | $1000 |
| Days 31-60 | $2000 |
| Days 61 and later | $5000 |

bb. Violation of Subparagraph 67.d. Failure to ensure that a Temporary-Use Flare that falls under the conditions of Paragraph 67.d.i or Paragraph 67.d.ii complies with the requirements of those Subparagraphs:

| Number of Days Temporary-Use Flare did not comply | Penalty per Day |
|---|---|
| Days 1-7 | $1000 |
| Days 8-15 | $2000 |
| Days 16 and later | $5000 |

cc. Violation of Paragraph 69 or 70. Failure to comply with the $H_2S$ emission limit at a Covered Flare or the LPG Flare after that Covered Flare or the LPG Flare becomes subject to Subpart J of the NSPS or Subpart Ja of the NSPS:

| On a per Covered Flare basis, Hours per calendar quarter in noncompliance | Penalty per Hour per Covered Flare |
|---|---|
| Hours 1-50.0 | $ 50 |
| Hours 51-100.0 | $100 |
| Hours over 100.0 | $200 |

For purposes of calculating the number of hours of noncompliance with the $H_2S$ limit, all one-hour periods of violation shall be added together to determine the total.

dd. Violation of Paragraph 71. Failure to timely decommission the SRU Flare in conformance with the requirements of Paragraph 71:

| Period of Delay or Noncompliance | Penalty per Day |
|---|---|
| Days 1-30 | $1000 |
| Days 31-60 | $2500 |
| Days 61 and later | $5000 |

P. Requirements for Incorporation of Consent Decree Requirements into Federally Enforceable Permits

151. For each failure to submit an application to incorporate Consent Decree requirements into relevant local, state and/or federal permits as required by Paragraph 83:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1500 |
| Beyond 60th day after deadline | $3000 |

Q. Requirements for SEP Implementation

152. For failure to comply with any requirement of Paragraphs 88-94 and Appendix E:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $500 |
| 31st through 60th day after deadline | $1500 |
| Beyond 60th day after deadline | $3000 |

R. Requirements for Reporting and Record Keeping

153. For each failure to submit reports as required by Part VIII, per report, per day:

| Period of Delay or Non-Compliance | Penalty per Day |
|---|---|
| 1st through 30th day after deadline | $300 |
| 31st through 60th day after deadline | $1000 |
| Beyond 60th day after deadline | $2000 |

154. Reserved.

155. Reserved.

156. Reserved.

S. Requirements for Payment of Civil Penalties

157. For the failure to pay the civil penalties as specified in Part IX of this Consent Decree, BPP will be liable for $15,000 per day plus interest on the amount overdue at the rate specified in 28 U.S.C. § 1961(a).

T. General Provisions Related to Stipulated Penalties

158. Demand for Stipulated Penalties. BPP will pay stipulated penalties upon written demand by the United States by no later than sixty (60) days after BPP receives such demand. A demand for the payment of stipulated penalties will identify the particular violation(s) to which the stipulated penalty relates, the stipulated penalty amount that the United States is demanding for each violation (as can be best estimated), the calculation method underlying the demand, and the grounds upon which the demand is based. The United States may, in its unreviewable discretion, waive payment of all or any portion of stipulated penalties that may accrue under this Consent Decree.

159. Payment of Stipulated Penalties. Stipulated penalties shall be apportioned as follows: 70% to the United States and 30% to Indiana. Stipulated penalties owing to the United States of under $10,000 will be paid by check and made payable to "U.S. Department of Justice," referencing DOJ Number 90-5-2-09244, and delivered to the U.S. Attorney's Office in the Northern District of Indiana. Stipulated penalties owing to the United States of $10,000 or more and stipulated penalties owing to Indiana will be paid in the manner set forth in Part X ("Civil Penalty").

160. Stipulated Penalties Dispute. Stipulated penalties will begin to accrue on the day after performance is due or the day a violation occurs, whichever is applicable, and will continue to accrue until performance is satisfactorily completed or until the violation ceases. However, in the event of a dispute over stipulated penalties, stipulated penalties will not accrue commencing upon the date BPP files a petition with the Court under Part XIV ("Retention of Jurisdiction/Dispute Resolution") if BPP has placed the disputed amount demanded in a commercial escrow account with interest. If the dispute thereafter is resolved in BPP's favor, the escrowed amount plus accrued interest will be returned to BPP; otherwise, the United States and Indiana (as applicable) will be entitled

to the amount that was determined to be due by the Court, plus the interest that has accrued in the escrow account on such amount.

161. The United States and Indiana reserve the right to pursue any other nonmonetary remedies to which they are legally entitled, including but not limited to, injunctive relief, for BPP's violations of this Consent Decree. Where a violation of this Consent Decree is also a violation of the Clean Air Act, its regulations, or a federally-enforceable state law, regulation, or permit, the United States will not seek civil penalties where it already has demanded and secured stipulated penalties from BPP for the same violations nor will the United States demand stipulated penalties from BPP for a Consent Decree violation if the United States has commenced litigation under the Clean Air Act for the same violations. Where a violation of this Consent Decree is also a violation of state law, regulation or a permit, Indiana will not seek civil penalties where the United States already has demanded and/or secured stipulated penalties from BPP for the same violations.

## XI. INTEREST

162. BPP will be liable for interest on the unpaid balance of the civil penalty specified in Part IX, and for interest on any unpaid balance of stipulated penalties to be paid in accordance with Part X. All such interest will accrue at the rate established pursuant to 28 U.S.C. § 1961(a) – *i.e.*, a rate equal to the coupon issue yield equivalent (as determined by the Secretary of Treasury) of the average accepted auction price for the last auction of 52-week U.S. Treasury bills settled prior to the Date of Lodging of the Consent Decree. Interest will be computed daily and compounded annually. Interest will be calculated from the date payment is due under the Consent Decree through the date of actual payment. For the purposes of this Paragraph, interest pursuant to this Paragraph will cease to accrue on the amount of any stipulated penalty payment made into an interest bearing escrow account as contemplated by Paragraph 160 of this Consent Decree. Monies timely paid into escrow will not be considered to be an unpaid balance under this Part.

## XII. RIGHT OF ENTRY

163. Any authorized representative of EPA or the State of Indiana, upon presentation of credentials, will have a right of entry upon the premises of the Whiting Refinery at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and systems, and inspecting all records maintained by the Whiting Refinery required by this Consent Decree or deemed necessary by EPA or IDEM to verify compliance with this Consent Decree. Except where other time periods specifically are noted, the Whiting Refinery will retain such records for the period of the Consent Decree. Nothing in this Consent Decree will limit the authority of EPA or IDEM to conduct tests, inspections, or other activities under any statutory or regulatory provision.

## XIII. FORCE MAJEURE

164. "*Force majeure*," for purposes of this Consent Decree, is defined as any event arising from causes beyond the control of BPP, of any entity controlled by BPP, or of BPP's contractors, which delays or prevents the performance of any obligation under this Consent Decree or causes a violation of any provision of this Consent Decree despite BPP's best efforts to fulfill the obligation. The requirement that BPP exercise "best efforts to fulfill the obligation" includes using best efforts to anticipate any potential *force majeure* event and best efforts to address the effects of any such event (a) as it is occurring and (b) after it has occurred to prevent or minimize any resulting delay to the greatest extent possible. *"Force Majeure"* does not include BPP's financial inability to perform any obligation under this Consent Decree.

165. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree, as to which BPP intends to assert a claim of Force Majeure, BPP shall notify EPA and IDEM in writing as soon as practicable, but in no event later than fifteen (15) calendar days following the date BPP first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay. The notice shall include an explanation and description of the reasons for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to prevent

or mitigate the delay or the effect of the delay; and BPP's rationale for attributing such delay to a *force majeure* event BPP shall include with any notice all available documentation supporting the claim that the delay was attributable to a *force majeure*. Failure to comply with the above requirements shall preclude BPP from asserting any claim of *force majeure* for that event for the period of time of such failure to comply, and for any additional delay caused by such failure. BPP shall be deemed to know of any circumstance of which BPP, any entity controlled by BPP, or BPP's contractors knew or should have known.

166. If EPA, after a reasonable opportunity for review and comment by IDEM, agrees that the delay or anticipated delay is attributable to a *force majeure* event, the time for performance of the obligations under this Consent Decree that are affected by the *force majeure* event will be extended by EPA, after a reasonable opportunity for review and comment by IDEM, for such time as is necessary to complete those obligations. An extension of the time for performance of the obligations affected by the force majeure event shall not, of itself, extend the time for performance of any other obligation. EPA will notify BPP in writing of the length of the extension, if any, for performance of the obligations affected by the force majeure event.

167. If EPA, after a reasonable opportunity for review and comment by IDEM, does not agree that the delay or anticipated delay has been or will be caused by a *force majeure* event, EPA will notify BPP in writing of its decision.

168. If BPP elects to invoke the dispute resolution procedures set forth in Part XIV ("Dispute Resolution"), it shall do so no later than 15 days after receipt of EPA's notice. In any such proceeding, BPP shall have the burden of demonstrating by a preponderance of the evidence that the delay or anticipated delay has been or will be caused by a *force majeure* event, that the duration of the delay or the extension sought was or will be warranted under the circumstances, that best efforts were exercised to avoid and mitigate the effects of the delay, and that BPP complied with the requirements of Paragraphs 164 and 165, above. If BPP carries this burden, the delay at issue shall be deemed not to be a violation by BPP of the affected obligation of this Consent Decree identified to EPA and the Court.

## XIV. RETENTION OF JURISDICTION/DISPUTE RESOLUTION

169. This Court will retain jurisdiction of this matter for the purposes of implementing and enforcing the terms of the Consent Decree and for the purpose of adjudicating all disputes of the Consent Decree between the United States and BPP that may arise under the provisions of this Consent Decree, until the Consent Decree terminates in accordance with Part XVII of this Consent Decree.

170. Unless otherwise expressly provided for in this Consent Decree, the dispute resolution procedures of this Part shall be the exclusive mechanism to resolve disputes arising under or with respect to this Consent Decree. BPP's failure to seek resolution of a dispute under this Part shall preclude BPP from raising any such issue as a defense to an action by the United States to enforce any obligation of BPP arising under this Decree.

171. Informal Dispute Resolution. Any dispute subject to Dispute Resolution under this Consent Decree shall first be the subject of informal negotiations. The dispute shall be considered to have arisen when BPP sends the United States a written Notice of Dispute. Such Notice of Dispute shall state clearly the matter in dispute. The period of informal negotiations shall not exceed 60 Days from the date the dispute arises, unless that period is modified by written agreement. If the Parties cannot resolve a dispute by informal negotiations, then the position advanced by the United States shall be considered binding unless, within 30 Days after the United States has notified BPP of the conclusion of the informal negotiation period, BPP invokes formal dispute resolution procedures as set forth below.

172. Formal Dispute Resolution. BPP shall invoke formal dispute resolution procedures, within the time period provided in the preceding Paragraph, by serving on the United States a written Statement of Position regarding the matter in dispute. The Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting BPP's position and any supporting documentation relied upon by BPP.

173. The United States shall serve its Statement of Position within 45 Days of receipt of BPP's Statement of Position. The United States' Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting that

position and any supporting documentation relied upon by the United States. The United States' Statement of Position shall be binding on BPP, unless BPP files a motion for judicial resolution of the dispute in accordance with the following Paragraph.

174. BPP may seek judicial resolution of the dispute by filing with the Court and serving on the United States, in accordance with Paragraph 210 of this Consent Decree ("Notice"), a motion requesting judicial resolution of the dispute. The motion must be filed within 20 Days of receipt of the United States' Statement of Position pursuant to the preceding Paragraph. The motion shall contain a written statement of BPP's position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief requested and any schedule within which the dispute must be resolved for orderly implementation of the Consent Decree.

175. The United States shall respond to BPP's motion within the time period allowed by the Local Rules of this Court. BPP may file a reply memorandum, to the extent permitted by the Local Rules.

176. Standard of Review. In all disputes arising under the Consent Decree, BPP shall bear the burden of demonstrating that its position complies with this Consent Decree and the CAA and that BPP is entitled to relief. The United States reserves the right to argue that its position is reviewable only on the administrative record and must be upheld unless arbitrary and capricious or otherwise not in accordance with law, and BPP reserves the right to argue to the contrary.

177. The invocation of dispute resolution procedures under this Part shall not, by itself, extend, postpone, or affect in any way any obligation of BPP under this Consent Decree unless and until final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first Day of noncompliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 162. If BPP does not prevail on the disputed issue, stipulated penalties shall be assessed and paid as provided in Part X ("Stipulated Penalties"). As part of the resolution of any dispute under this Part, the Parties, by agreement, or the Court, by order, may, in appropriate circumstances, extend or modify the schedule for completion of work under this Consent Decree to account for the delay in work that

occurred as a result of the dispute resolution process. BPP shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extension or modified schedule.

## XV. EFFECT OF SETTLEMENT

178. Definitions. For purposes of this Part XV (Effect of Settlement), the following definitions apply:

a. "Hazardous Air Pollutants" or "HAPs" shall have the meaning set forth in 42 U.S.C. § 7412(b)(1);

b. "Whiting Refinery Modernization Project" or "WRMP" shall mean: 1) the projects authorized to be constructed and operated at the Whiting Refinery pursuant to Significant Source Modification 089-25484-00453 issued by IDEM on May 1, 2008 and Part 70 Permit T089-6741-00453 as modified by Significant Permit Modification 089-25488-00453 issued by IDEM on June 16, 2008, and 2) any other contemporaneous project included for emissions netting purposes and identified in the same permits. This project originally was named the "CXHO Project," was subsequently re-named the "Operation Canadian Crude Project," and later was re-named the "Whiting Refinery Modernization Project;"

c. "Post-Lodging Compliance Dates" shall mean any dates in this Part XV ("Effect of Settlement") after the Date of Lodging;

d. "PSD/NNSR Requirements" shall mean the Prevention of Significant Deterioration and Non-Attainment New Source Review requirements found in the following: 42 U.S.C. § 7475; 40 C.F.R. §§ 52.21(a)(2)(iii) and 52.21(j) - 52.21(r)(5); 42 U.S.C. §§ 7502(c)(5), 7503(a)-(c); 40 C.F.R. Part 51, Appendix S, Part IV, Conditions 1-4; any applicable, federally approved and federally enforceable state or local regulation that implements, adopts, or incorporates the federal provisions cited in this Paragraph; any Title V permit requirement that implements, adopts, or incorporates the federal, or federally approved state, provisions cited in this Paragraph; and any applicable state or local regulation enforceable by the State of Indiana that implements, adopts, or incorporates the federal provisions cited in this Paragraph;

e. "Stayed Subpart Ja Requirements" shall mean the following requirements of 40 C.F.R. Part 60, Subpart Ja, that are currently stayed pursuant to 73 *Fed. Reg.* 78,549 (Dec. 22, 2008);

i. $SO_2$ and $H_2S$ emissions limits applicable to flares (set forth in 40 C.F.R. § 60.102a(g)(1) (2010));

ii. $SO_2$ emissions limits applicable to heaters (set forth in 40 C.F.R. § 60.102a(g)(1) (2010));

iii. NOx emission limits applicable to heaters (set forth in 40 C.F.R. § 60.102a(g)(2) (2010));

iv. Sulfur monitoring for flares (set forth in 40 C.F.R. § 60.107a(d) (2010)); and

v. Flow monitoring for flares (set forth in 40 C.F.R. § 60.107a(e) (2010)).

If a final rule encompassing these Stayed Subpart Ja Requirements places them in different locations in Subpart Ja with different citations, the definition herein refers to the subject of the regulation (*e.g.*, "$SO_2$ emission limits applicable to flares") and not to the citation.

179. Entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana for the violations that occurred through the Date of Lodging of the Consent Decree as alleged in the Complaints (filed by the United States and the State concurrently with the lodging of this Consent Decree).

180. Resolution of Claims Alleged in Notices of Violation ("NOVs") and Findings of Violations ("FOVs"). Entry of this Consent Decree shall resolve the civil claims of the United States for the violations that occurred through the Date of Lodging of the Consent Decree as alleged in the following NOVs and FOVs:

a. FOV – EPA-5-07-IN-03 (Jan. 25, 2007);

b. NOV/FOV – EPA-5-08-IN-01 (Nov. 29, 2007);

c. Amendment to NOV/FOV – EPA-5-08-IN-01 (Oct. 1, 2008) at the process units identified by unit name and number;

d. NOV – EPA-5-09-IN-13 (May 18, 2009); and

e. FOV – EPA-5-10-04-IN (Feb. 11, 2010).

These NOVs and FOVs are attached hereto in Appendix F.

181. <u>Resolution of Claims for Violating PSD/NNSR Requirements at the Covered, LPG, and SRU Flares</u>. With respect to emissions of $SO_2$, VOCs, CO and $H_2S$ from the following flares, entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for violations of the PSD/NNSR Requirements resulting from construction or modification that occurred during the WRMP from the date those claims accrued through the following dates:

| | | |
|---|---|---|
| a. | SRU, DDU, GOHT, and South flares | Date of Lodging |
| b. | LPG flare | December 31, 2012 |
| c. | FCU, VRU, and Alky flares | December 31, 2015 |
| d. | 4UF flare | December 31, 2016 |
| e. | UIU flare | December 31, 2017 |

182. <u>Resolution of Claims for Violating PSD/NNSR Requirements at Other Process Units</u>. With respect to emissions of the following pollutants from the following process units, entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for violations of the PSD/NNSR Requirements resulting from construction or modification that occurred during the WRMP from the date those claims accrued through the Date of Lodging:

a. At FCU 500 and 600 with respect to $SO_2$ and NOx;

b. At the Whiting New Coker (also referred to as the #2 Coker) with respect to VOCs, $H_2S$, $PM_{TOTAL}$, and $PM_{10}$; and

c. At the following heaters and units:

i. With respect to NOx: the #2 Coker heaters (F-201, F-202, and F-203); and

ii. With respect to $SO_2$:

A. 11 A Pipestill heaters (H-1X, H-2, and H-3);

B. 11 C Pipestill heaters (H-200 and H-300);

C. 12 Pipestill heaters (H-101A, H-101B, and H-102);

D. #2 Coker heaters (F-201, F-202, and F-203);

E. GOHT heaters (F-901A and F-901B);

F. BOU F-401 furnace;

G. ISOM H-1 heater;

H. New Hydrogen Unit heaters (HU-1 and HU-2);

I. HU B-501;

J. CFHU heaters (F-801A, F-801B, and F-801C);

K. DDU heaters (WB-301 and WB-302);

L. 4UF heaters (F-1, F-2, F-3, F-4, F-5, F-6, F- 7, F-8A, and F-8B);

M. ARU heaters (F-200A and F-200B);

N. CRU heaters (F-101 and F-102A);

O. 3SPS boilers (#1, #2, #3, #4, and #6);

P. 3SPS Duct Burners; and

Q. New Boiler 1.

183. <u>Resolution of Pre-Lodging Claims Under Listed Regulations at the Covered Flares, LPG Flare, and Other Process Units</u>. With respect to emissions of the following pollutants at the following flares and process units, entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for violations of the listed regulations and any applicable state regulations that implement, adopt, or incorporate any of the listed regulations that occurred from December 1, 2002 through the Date of Lodging:, except that the violations of 40 C.F.R. § 60.102a(f)(1)(ii) shall be resolved from September 26, 2008 through the Date of Lodging:

| **Flare(s)/ Process Unit(s)** | **Pollutant(s)** | **Regulation(s)** |
|---|---|---|
| Covered Flares and LPG Flare | VOCs and HAPs | 40 C.F.R. § 60.11(d);<br><br>40 C.F.R. §§ 60.18(c)(1)-(2), (c)(3)(ii), (c)(4)-(5), (d), (e) and (f);<br><br>40 C.F.R. § 63.6(e)(1)(i);<br><br>40 C.F.R. §§ 63.11(b)(1), (3)-(5), (6)(ii), and (7)-(8);<br><br>40 C.F.R. § 60.482-10(d), but only to the extent that this provision requires compliance with 40 C.F.R. §§ 60.18(c)(3)(ii) and (d);<br><br>40 C.F.R. § 60.482-10(e), but only to the extent that this provision relates to flares;<br><br>40 C.F.R. § 60.592(a), but only to the extent that this provision: (a) relates to flares, and (b) requires compliance with 40 C.F.R. §§ 60.18(c)(3)(ii) and (d);<br><br>40 C.F.R. §§ 63.643(a)(1), 63.648(a), and Table 6 of Part 63, Subpart CC, but only to the extent that these provisions: (a) relate to flares, and (b) require compliance with 40 C.F.R. §§ 60.18(c)(3)(ii) and (d), 63.6(e)(1)(i), and 63.11(b)(1) and (b)(6)(ii); and<br><br>40 C.F.R. § 63.1566(a)(1)(i) and Tables 15 and 44 of Part 63, Subpart UUU, but only to the extent that these provisions: (a) relate to flares, and (b) require compliance with 40 C.F.R. §§ 63.11(b)(1), (b)(6)(ii) and (e)(1). |
| Covered Flares and LPG Flare | $SO_2$ and $H_2S$ | 40 C.F.R. Part 60, Subparts A and J |
| FCU 500 and FCU 600 | $SO_2$, CO, NOx and PM | 40 C.F.R. Part 60, Subparts A, J, and Ja |
| Heaters, boilers, and other units listed in Paragraph 185.b | $SO_2$ | 40 C.F.R. Part 60, Subparts A and J. |

| **Flare(s)/ Process Unit(s)** | **Pollutant(s)** | **Regulation(s)** |
|---|---|---|
| Sulfur Pits A, B, C, and 2400 | $H_2S$ and reduced sulfur compounds | 40 C.F.R. §§ 60.102a(f)(1)(ii), 60.106a(a)(2), and 40 C.F.R. Part 60, Subparts A and J |

184. Resolution of Claims Continuing Post-Lodging Under Listed Regulations at the Covered Flares and the LPG Flare.

a. Resolution of Claims for Failure to Comply with Requirements Related to Monitoring, Operation, and Maintenance According to Flare Design. With respect to emissions of VOCs and HAPs at the following flares, entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for violations of the listed regulations from the Date of Lodging through the following dates, but only to the extent that these claims are based upon BPP's use of too much steam in relation to vent gas flow:

<table>
<tr><th>Flare(s)</th><th>Date</th><th>Regulation(s)</th></tr>
<tr><td>LPG Flare</td><td>1 year after Date of Entry</td><td rowspan="2">40 C.F.R. §§ 60.18(d);<br><br>40 C.F.R. §§ 63.11(b)(1);<br><br>40 C.F.R. § 60.482-10(d), but only to the extent that this provision requires compliance with 40 C.F.R. § 60.18(d);<br><br>40 C.F.R. § 60.482-10(e), but only to the extent that this provision relates to flares;<br><br>40 C.F.R. § 60.592(a), but only to the extent that this provision: (a) relates to flares, and (b) requires compliance with 40 C.F.R. § 60.18(d);<br><br>40 C.F.R. §§ 63.643(a)(1) and 63.648(a), but only to the extent that these provisions: (a) relate to flares, and (b) require compliance with 40 C.F.R. §§ 60.18(d) and 63.11(b)(1); and<br><br>40 C.F.R. § 63.1566(a)(1)(i) and Table 15 of Part 63, Subpart UUU, but only to the extent that these provisions: (a) relate to flares, and (b) require compliance with 40 C.F.R. § 63.11(b)(1).</td></tr>
<tr><td>Covered Flares</td><td>December 31, 2014</td></tr>
</table>

b. Resolution of NSPS Subpart J Claims. With respect to emissions of $SO_2$ at the following flares, entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for violations of the listed regulations from the Date of Lodging through the following dates:

| **Flare(s)** | **40 C.F.R. § 60.104(a)(1) (Standards for sulfur oxides)** | **40 CFR § 60.105(a)(4) (Monitoring of emissions and operations)** |
|---|---|---|
| FCU | December 31, 2015 | December 31, 2013 |
| VRU | December 31, 2015 | December 31, 2013 |
| Alky | December 31, 2015 | December 31, 2013 |
| 4UF | December 31, 2016 | December 31, 2013 |
| UIU | December 31, 2017 | December 31, 2013 |

185. Conditional Resolution of Claims Under Stayed NSPS Subpart Ja Requirements. If EPA lifts the stay on the Stayed Subpart Ja Requirements and promulgates final regulations encompassing the Stayed Subpart Ja Requirements, then entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for violations of the Stayed Subpart Ja Requirements as follows:

a. For the following flares and the following Stayed Subpart Ja Requirements, from the date that a final rule encompassing the Stayed Subpart Ja Requirements is effective through the following dates:

| Name of Flare | $SO_2$ and $H_2S$ Emission Limits (currently at 40 C.F.R. § 60.102a(g)(1)) | Sulfur and Flow Monitoring (currently at 40 C.F.R. §§ 60.107a(d), (e)) |
|---|---|---|
| DDU | Date of Lodging | December 31, 2013 |
| FCU | December 31, 2015 | December 31, 2013 |
| VRU | December 31, 2015 | December 31, 2013 |
| Alky | December 31, 2015 | December 31, 2013 |
| 4UF | December 31, 2016 | December 31, 2013 |
| UIU | December 31, 2017 | December 31, 2013 |

b. For the following heaters and units with respect to the following pollutants, from the date that a final rule encompassing the Stayed Subpart Ja

Requirements is effective through the Date of Lodging, except for 11 C Pipestill heater H-200:

i. With respect to NOx emissions (currently, the limit is set forth in stayed provision 40 C.F.R. § 60.102a(g)(2)):

A. 12 Pipestill heaters (H-101A, H-101B, and H-102);

B. 11 C Pipestill heater H-200 through December 31, 2013;

C. #2 Coker heaters (F-201, F-202, and F-203);

D. GOHT heaters (F-901A and F-901B); and

E. BOU F-401 furnace.

ii. With respect to $SO_2$ emissions (currently, the limit is set forth in stayed provision 40 C.F.R. § 60.102a(g)(1)):

A. 11 A Pipestill heaters (H-1X, H-2, and H-3);

B. 11 C Pipestill heaters (H-200 and H-300);

C. 12 Pipestill heaters (H-101A, H-101B, and H-102);

D. #2 Coker heaters (F-201, F-202, and F-203);

E. GOHT heaters (F-901A and F-901B);

F. BOU F-401 furnace;

G. ISOM H-1 Heater;

H. New Hydrogen Unit Heaters (HU-1 and HU-2);

I. HU B-501;

J. CFHU heaters (F-801A, F-801B, and F-801C);

K. DDU heaters (WB-301 and WB-302);

L. 4UF heaters (F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B);

M. ARU heaters (F-200A and F-200B);

N. CRU heaters (F-101 and F-102A);

O. 3SPS boilers (#1, #2, #3, #4, and #6);

P. 3SPS Duct Burners; and

Q. New Boiler 1.

186. Resolution of LDAR violations. Entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for violations of (i) 40 C.F.R. Part 60, Subpart GGG and GGGa; (ii) 40 CFR Part 61, Subparts J and V; (iii) the LDAR provisions of 40 C.F.R. Part 63, Subpart CC; and (iv) 326 I.A.C. 8-4-8, that occurred from December 1, 2002 through the Date of Lodging of the Consent Decree at each process unit (as defined by 40 C.F.R. § 60.590a(e)) at the Whiting Refinery.

187. Resolution of Liability Regarding Benzene Waste NESHAP Requirements. Entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for violations of 40 C.F.R. Part 61, Subpart FF that occurred from December 1, 2002 through the Date of Lodging of the Consent Decree at waste management units at the Whiting Refinery.

188. Resolution of Title V violations. Entry of this Consent Decree shall resolve the civil claims of the United States and the State of Indiana against BPP for the violations at the Whiting Refinery of Sections 502(a), 503(c), and 504(a) of the CAA, 42 U.S.C. §§ 7661a(a), 7661b(c), 7661c(a), and of 40 C.F.R. §§ 70.1(b), 70.5(a) and (b), 70.6(a) and (c), and 70.7(b), that are based upon the violations resolved by Paragraphs 181-184, 186 and 187 for the time frames set forth in those Paragraphs.

189. Resolution of Consent Decree violations. Entry of this Consent Decree shall resolve the civil claims of the United States against BPP for the following violations at the Whiting Refinery of the Consent Decree entered on August 29, 2001 in *United States, et al. v. BP Exploration and Oil Co., et al.*, Civil No. 2:96 CV 095 RL (N.D. Ind.):

a. Violations of Paragraph 19.A.ii. (Facility Current Compliance Status) that occurred prior to December 31, 2008;

b. Violations of Paragraphs 20.B.i. (Training), 20.D (Leak Definition), 20.G First Attempt at Repair on Valves), 20.H.i. (LDAR Monitoring Frequency), 20.L (Adding New Valves and Pumps), and 20.S (Quarterly Reports) that occurred prior to the Date of Lodging; and

c. Violations of Paragraph 21.A (Sulfur Pit Emissions) that occurred at Sulfur Pits, A, B, C, and 2400 that occurred prior to the Date of Lodging.

190. The resolutions of liability in this Part are based exclusively on claims at BPP's Whiting Refinery.

191. Reservation of Rights: Resolution in Paragraphs 181, 184, 185 and 187 Can Be Rendered Void. Notwithstanding the resolutions of liability contained in Paragraphs 181, 184, 185 and 187 for the period of time between the Date of Lodging and the Post-Lodging Compliance Dates, those resolutions of liability shall be rendered void if BPP materially fails to comply with any of the obligations and requirements of Section F (NOx Emissions Reductions from Heaters and Boilers), Section O (Emissions Reductions from Flares and Control of Flaring Events), and Section P (Incorporation of Consent Decree Requirements into Federally Enforceable Permits) of Part V, and Part VI (Emission Credit Generation). However, the resolutions of liability in Paragraphs 181, 184, 185 and 187 shall not be rendered void if BPP remedies such material failure as expeditiously as practicable and pays all stipulated penalties due as a result of such material failure.

192. The United States and IDEM further reserve all legal and equitable remedies available to enforce the provisions of this Consent Decree. This Consent Decree shall not be construed to limit the rights of the United States or IDEM to obtain penalties or injunctive relief under the CAA or implementing regulations, or under other federal or state laws, regulations, or permit conditions, except as expressly specified in Paragraphs 179-188. The United States and IDEM further reserve all legal and equitable

remedies to address any imminent and substantial endangerment to the public health or welfare or the environment arising at, or posed by, BPP's Whiting Refinery, whether related to the violations addressed in this Consent Decree or otherwise.

193. In any subsequent administrative or judicial proceeding initiated by the United States or IDEM for injunctive relief, civil penalties, other appropriate relief relating to the Whiting Refinery for violations of PSD/NSR, NSPS, NESHAP and/or LDAR requirements not identified in this Part:

a. BPP shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, claim-splitting, or other defenses based upon any contention that the claims raised by the United States or IDEM in the subsequent proceeding were or should have been brought in the instant case, except with respect to claims that have been specifically resolved pursuant to Paragraphs 179-188 of this Part and for which the resolution of liability has not been voided pursuant to Paragraph 190.

b. Except as set for in Subparagraph a., the United States and the State of Indiana may not assert or maintain that this Consent Decree constitutes a waiver, or determination of, or otherwise obviates, any claim or defense by BPP whatsoever, or that this Consent Decree constitutes an acceptance by BPP of any interpretation or guidance issued by EPA related to the matters addressed in this Consent Decree.

194. This Consent Decree is not a permit, or a modification of any permit, under any federal, State, or local laws or regulations. BPP is responsible for achieving and maintaining complete compliance with all applicable federal, State, and local laws, regulations, and permits; and BPP's compliance with this Consent Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as set forth herein. The United States and IDEM do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that BPP's compliance with any aspect of this Consent Decree will result in compliance with provisions of the Act, 42 U.S.C. § 7401 *et seq.*, or with any other provisions of federal, State, or local laws, regulations, or permits.

195. This Consent Decree does not limit or affect the rights of BPP, the United States, or IDEM against any third parties that are not party to this Consent Decree, nor does it limit the rights of third parties that are not party to this Consent Decree against BPP, except as otherwise provided by law.

196. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third party not party to this Consent Decree.

197. Nothing in this Consent Decree will be construed to limit or disqualify BPP, on the grounds that information was not discovered voluntarily, from seeking to apply EPA's Audit policy to any violation or noncompliance that BPP discovers during the course of any audit, investigation, or enhanced monitoring the BPP is required to undertake pursuant to this Consent Decree.

198. Resolution of Citizen-Intervenors Claims. In consideration of the commitments and agreements being made by BPP in this Consent Decree, Citizen-Intervenors hereby agree as follows:

a. Citizen-Intervenors shall not file or support the filing (by providing legal representation or financial contributions over which the Citizen-Intervenors have control) of any judicial or administrative objection(s), appeal(s), petitions(s) for review, petition to EPA pursuant to Section 505(b)(2) of the Clean Air Act, or citizen suit(s) relating to:

i. the issuance of any Source Modification Permit or any revision of the WRMP Operating Permit that is required by, contemplated by or necessary to implement this Consent Decree and the settlement of claims embodied herein; or

ii. any allegation that WRMP has been constructed or will operate without required permits;

provided that the foregoing shall not apply if the terms and conditions of any such permit differ in material respects from the terms and conditions of the draft terms and conditions that have been provided to Citizen-Intervenors prior to the date hereof and Citizen-Intervenors have not consented to such differences. The foregoing shall not prohibit the Citizen-Intervenors from communicating with other groups or individuals.

b. Upon the later of the (i) Date of Entry of this Consent Decree and (ii) the issuance of the WRMP Operating Permit in materially the same form as has been provided to the Citizen-Intervenors prior to the date hereof or with such modifications as have been consented to by the Citizen-Intervenors, Save the Dunes, Sierra Club, the Hoosier Environmental Council, Tom Tsourlis and Susan Eleuterio shall dismiss with prejudice their petitions for review pending before the OEA in Cause Nos. 08-A-J-4115 and 08-A-J-4142.

c. Citizen-Intervenors shall not file a citizen suit or support the filing (by providing legal representation or financial contributions over which Citizen-Intervenors have control) of any third party action related to the acts or omissions that form the basis of the claims of the United States and Indiana that are resolved in Part XV.

d. Citizen-Intervenors may seek to enforce the obligations of BPP under this Decree, except for the obligations under Part IX (Civil Penalty) and Part X (Stipulated Penalties), by filing with the Court a motion for appropriate relief. Such motion shall be governed by the Federal Rules of Civil Procedure and applicable law.

e. BPP's sole and exclusive remedy for a breach of this Agreement by Citizen-Intervenors shall be an action for specific performance or injunction. In no event shall BPP be entitled to monetary damages for breach of this Agreement. In addition, no legal action for specific performance or injunction shall be brought or maintained until: (a) BPP provides written notice to the breaching Party which explains with particularity the nature of the claimed breach, and (b) within (30) days after receipt of said notice, the breaching Party fails to cure the claimed breach or, in the case of a claimed breach which cannot be reasonably remedied within a thirty (30) day period, the breaching Party fails to commence to cure the claimed breach within such (30) day period, and thereafter diligently complete the activities reasonably necessary to remedy the claimed breach.

## XVI. GENERAL PROVISIONS

199. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree will relieve BPP of its obligations to comply with all applicable federal, state, regional and local laws and regulations, including, but not limited to, more stringent standards. In addition, nothing in this Consent Decree will be construed to prohibit or prevent the United States or IDEM from developing, implementing, and enforcing more stringent standards subsequent to the Date of Lodging of this Consent Decree through rulemaking, the permit process, or as otherwise authorized or required under federal, state, regional, or local laws, or as otherwise authorized or required under federal, state, regional, or local laws and regulations. Subject to Part XV ("Effect of Settlement"), Part X ("Stipulated Penalties"), and Paragraph 201 ("Permit Violations") of this Consent Decree, nothing contained in this Consent Decree will be construed to prevent or limit the rights of the United States or IDEM to seek or obtain other remedies or sanctions available under other federal, state, regional, or local statutes or regulations, by virtue of BPP's violations of the Consent Decree or of the statutes and regulations upon which the Consent Decree is based, or for BPP's violations of any applicable provision of law. This will include the right of the United States or IDEM to invoke the authority of the Court to order BPP's compliance with this Consent Decree in a subsequent contempt action. The requirements of this Consent Decree do not exempt BPP from complying with any and all new or modified federal, state, regional, and/or local statutory or regulatory requirements that may require technology, equipment, monitoring, or other upgrades after the Date of Lodging of this Consent Decree.

200. Startup, Shutdown, and Malfunction. Notwithstanding the provisions of this Consent Decree regarding Startup, Shutdown, and Malfunction, this Consent Decree does not exempt BPP from the requirements of state laws and regulations or from the requirements of any permits or plan approvals issued to BPP, as these laws, regulations, permits, and/or plan approvals may apply to Startups, Shutdowns, and Malfunctions.

201. Permit Violations. Except as specifically identified in Part XV ("Effect of Settlement"), nothing in this Consent Decree will be construed to prevent or limit the

right of the United States or IDEM to seek injunctive or monetary relief for violations of permits; provided, however, that with respect to monetary relief, the United States and IDEM must elect between filing a new action for such monetary relief or seeking stipulated penalties under this Consent Decree, if stipulated penalties also are available for the alleged violation(s).

202. Failure of Compliance. The United States and IDEM do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that BPP's complete compliance with the Consent Decree will result in compliance with the provisions of the CAA or the corollary state and local statutes. Notwithstanding the review or approval by EPA or IDEM of any plans, reports, policies or procedures formulated pursuant to the Consent Decree, BPP will remain solely responsible for compliance with the terms of the Consent Decree, all applicable permits, and all applicable federal, state, regional, and local laws and regulations, except as provided in Part XIII ("Force Majeure").

203. Changes to Law. In the event that during the life of this Consent Decree there is a change to the statutes or regulations that provide the underlying basis for the Consent Decree such that BPP would not otherwise be required to perform any of the obligations herein or would have the option to undertake or demonstrate compliance in an alternative or different manner, BPP may petition the Court for relief from any such requirements, in accordance with Fed. R. Civ. P. 60. However, if BPP applies to the Court for relief under this Paragraph, the United States reserves the right to seek to void all or part of the Resolution of Liability reflected in Part XVII ("Effect of Settlement"). Nothing in this Paragraph is intended to enlarge the Parties' rights under Fed. R. Civ. P. 60, nor is this Paragraph intended to confer on any Party any independent basis, outside of Fed. R. Civ. P. 60, for seeking such relief.

204. Alternative Monitoring Plans. If, for any monitoring required by this Consent Decree (other than CEMS), BPP submits an AMP to EPA for approval, then BPP shall comply with the proposed AMP pending EPA's approval or disapproval of the submitted AMP. If an AMP is not approved, then within ninety (90) Days of BPP's receipt of disapproval, BPP will submit to EPA for approval a plan and schedule that provide for compliance with the applicable monitoring requirements as soon as

practicable. Such plan may include physical or operational changes to the equipment, or additional or different monitoring.

205. Service of Process. BPP hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Fed. R. Civ. P. 4 and any applicable local rules of this Court, including, but not limited to, service of a summons.

206. Post-Lodging, Pre-Entry Obligations. Obligations of BPP under this Consent Decree to perform duties after the Date of Lodging but prior to the Date of Entry shall be legally enforceable only on or after the Date of Entry. Liability for stipulated penalties, if applicable, shall accrue for violations of such obligations, and the United States may demand payment as provided in the Decree, provided that stipulated penalties accruing between the Date of Lodging and the Date of Entry may not be collected unless and until this Decree is entered by the Court.

207. Costs. Each Party to this action shall bear its own costs and attorneys' fees.

208. Public Documents. All information and documents submitted by BPP pursuant to this Consent Decree shall be subject to public inspection in accordance with applicable federal law, unless subject to legal privileges or protection, or identified and supported as trade secrets or confidential business information in accordance with the applicable federal statutes or regulations.

209. Public Notice and Comment. The Parties agree to this Consent Decree and agree that this Consent Decree may be entered upon compliance with the public notice procedures set forth at 28 C.F.R. § 50.7, and upon notice to the Court from the United States Department of Justice requesting entry of this Consent Decree. The United States reserves the right to withdraw or withhold its consent to this Consent Decree at any time prior to the Date of Entry if public comments disclose facts or considerations indicating that this Consent Decree is inappropriate, improper, or inadequate.

210. Notice. Unless otherwise provided herein, notifications to or communications between the Parties shall be deemed submitted on the date they are postmarked and sent by U.S. Mail or overnight mail, postage prepaid, or to EPA by electronic mail as provided below, except for notices under Part XV ("Force Majeure")

and Part XVI ("Retention of Jurisdiction/Dispute Resolution"), which shall be sent by overnight mail or by certified or registered mail, return receipt requested. Notifications to or communications mailed to BPP shall be deemed to be received on the earlier of (i) actual receipt by BPP or (ii) receipt of an electronic version sent to the addressees set forth in this Paragraph. Each report, study, notification, or other communication of BPP shall be submitted as specified in this Consent Decree. If the date for submission of a report, study, notification, or other communication falls on a Saturday, Sunday or federal holiday, the report, study, notification, or other communication will be deemed timely if it is submitted the next Working Day. Except as otherwise provided herein, all reports, notifications, certifications, or other communications required or allowed under this Consent Decree shall be addressed as follows:

As to the United States:

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611
Ben Franklin Station
Washington, DC 20044-7611
Reference Case No. 90-5-2-1-09244

As to EPA Headquarters:

Electronic submissions (and, if necessary, hard-copy submissions) shall be addressed to:

Director, Air Enforcement Division
Office of Civil Enforcement (2242A)
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20004

and submitted electronically to:
csullivan@matrixneworld.com
foley.patrick@epa.gov

Submissions not delivered electronically shall be sent to the address above and to:

Director, Air Enforcement Division
Office of Civil Enforcement
c/o Matrix New World Engineering, Inc.
120 Eagle Rock Ave., Suite 207
East Hannover, NJ 07936-3159

As to EPA Region 5:

Hard-copy and electronic submissions shall be addressed to:

Compliance Tracker (AE-17J)
Air Enforcement and Compliance Assurance Branch
U.S. EPA, Region 5
77 W. Jackson Blvd.
Chicago, IL 60604

and

Office of Regional Counsel
U.S. EPA, Region 5
77 West Jackson Blvd. (C-14J)
Chicago, IL 60604

and submitted electronically to:
csullivan@matrixneworld.com

Submissions not delivered electronically shall be sent to the address above.

As to the State of Indiana:

Office of the Indiana Attorney General
Environmental Litigation Division
Indiana Government Center South- Fifth Floor
302 West Washington Street
Indianapolis, IN 46204

Chief, Air Compliance and Enforcement Branch
Indiana Department of Environmental Management
100 North Senate Avenue
MC 61-53, IGCN 1003
Indianapolis, IN 46204-2251

As to BPP:

Refinery Manager
BPP Whiting Refinery
2815 Indianapolis Blvd.
Whiting, Indiana 46394

HSSE Manager
BPP Whiting Refinery
2815 Indianapolis Blvd.
Whiting, Indiana 46394

Managing Attorney – HSSE
BP America, Inc.
150 W. Warrenville Road
Mail Code 200-1W
Naperville, Illinois 60563

and submitted electronically to:
Whiting.CD.Tracker@bp.com

Any Party may change either the notice recipient or the address for providing notices to it by serving the other Party with a notice setting forth such new notice recipient or address. In addition, the nature and frequency of reports required by this Consent Decree may be modified by mutual consent of the Parties. The consent of the United States to such modification must be in the form of a written notification from EPA, but need not be filed with the Court to be effective.

211. Approvals. All EPA approvals or comments required under this Consent Decree shall be in writing.

212. Paperwork Reduction Act. The information required to be maintained or submitted pursuant to this Consent Decree is not subject to the Paperwork Reduction Act of 1980, 44 U.S.C. § 3501 et seq.

213. Modification. This Consent Decree contains the entire agreement of the Parties and will not be modified by any prior oral or written agreement, representation, or understanding. Non-material modifications to this Consent Decree will be effective when signed by the United States and BPP. The United States will file non-material modifications with the Court on a periodic basis. For purposes of this Paragraph, non-material modifications include, but are not limited to, modifications to the

frequency of reporting obligations and modifications to schedules that do not extend the date for compliance with emissions limitations following the installation of control equipment, provided that such changes are agreed upon in writing between the United States and BPP. Material modifications to this Consent Decree will be in writing, signed by the Parties, and will be effective upon approval by the Court. Specific provisions in this Consent Decree that govern specific types of modifications shall be effective as set forth in the specific provision governing the modification.

214. Effect of Shutdown. The permanent Shutdown of an emissions unit or equipment and the surrender of all permits for that emissions unit or equipment shall be deemed to satisfy all requirements of this Consent Decree applicable to that emissions unit or equipment on and after the later of: (i) the date of the permanent Shutdown of the emissions unit or equipment; and (ii) the date of the surrender of all permits applicable to the unit or piece of equipment. The permanent Shutdown of the Whiting Refinery and the surrender of all air permits for the Refinery shall be deemed to satisfy all requirements of this Consent Decree applicable to the Refinery on and after the later of: (i) the date of the Shutdown of the Refinery; or (ii) the date of the surrender of all air permits

## XVII. TERMINATION

215. Certification of Completion: Applicable Sections. Prior to moving for termination under Paragraph 220, BPP may seek to certify completion of one or more of the following Sections/Parts of the Consent Decree.

a. Part V, Sections A through E - Fluid Catalytic Cracking Units (including operation of the units for one (1) year in compliance with the final emission limits established pursuant to this Consent Decree);

b. Part V, Section F – $NO_x$ Emissions Reductions from Heaters and Boilers (including operation of the relevant units for one (1) year after installation of required emission controls and compliance with applicable emission limits established pursuant to this Consent Decree);

c. Part V, Section G – $SO_2$ Emissions Reductions from Heaters and Boilers (including operation of the relevant units for one (1) year after completion in compliance with the emission limits established pursuant to this Consent Decree);

d. Part V, Section H – Fuel Gas Sulfur Content (including operation of the relevant units for one (1) year after completion in compliance with the emission limits established pursuant to this Consent Decree);

e. Part V, Sections I through K – CEMS Downtime, Benzene NESHAP and LDAR;

f. Part V, Section L – Sulfur Recovery Plant (including operation of the relevant units for one (1) year after completion in compliance with the emission limits established pursuant to this Consent Decree);

g. Part V, Section M – Tanks (including operation of the relevant units for one (1) year after completion in compliance with the emission limits established pursuant to this Consent Decree);

h. Part V, Section N – Coker (including operation of the relevant units for one (1) year after completion in compliance with the emission limits established pursuant to this Consent Decree); and

i. Part V, Section O and Appendix D – Flares; (including operation of the relevant units for one (1) year after completion in compliance with the flare efficiency requirements and the flare flow cap established pursuant to this Consent Decree); and;

j. Part VII – Supplemental Environmental Project and Additional Injunctive Relief.

216. Certification of Completion: BPP Actions. If BPP concludes that any of the Section(s) or Part(s) identified in Paragraph 215 have been completed, BPP may submit a written report to EPA and IDEM describing the activities undertaken and certifying that the applicable Section(s) or Part(s) have been completed in full satisfaction of the requirements of this Consent Decree, and that BPP is in substantial and material compliance with the relevant Section of the Consent Decree. The report will contain the following statement, signed by a responsible corporate official of BPP.

> "I certify under penalty of law that this information was prepared under my direction or supervision by personnel qualified to properly gather and evaluate the information submitted. Based on my directions and after reasonable inquiry of the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate and complete."

217. Certification of Completion: EPA Actions. Upon receipt of BPP's certification, EPA will notify BPP whether the requirements set forth in the applicable Section(s) or Part(s) have been completed in accordance with this Consent Decree:

a. If EPA concludes that the requirements have not been fully complied with, EPA will notify BPP as to the activities that must be undertaken to complete the applicable Section. BPP will perform all activities described in the notice, subject to its right to invoke the dispute resolution procedures set forth in Part XVI ("Dispute Resolution"); and/or

b. If EPA concludes that the requirements of the applicable Section or Part have been completed in accordance with this Consent Decree, EPA will so certify in writing to BPP. This certification will constitute the certification of completion of the applicable Section or Part for purposes of this Consent Decree.

The parties recognize that ongoing obligations under such Sections remain and necessarily continue (*e.g.*, reporting, recordkeeping, training, auditing requirements), and that BPP's certification is that it is in current compliance with all such obligations.

218. Certification of Completion: No Impediment to Stipulated Penalty Demand. Nothing in Paragraphs 216 and 217 will preclude the United States from seeking stipulated penalties for a violation of any of the requirements of the Consent Decree regardless of whether a Certification of Completion has been issued under Subparagraph 217.b. In addition, nothing in this Paragraph will permit BPP to fail to implement any ongoing obligations under the Consent Decree regardless of whether a Certification of Completion has been issued.

219. Termination: Conditions Precedent. This Consent Decree will be subject to termination upon motion by the Parties or upon motion by BPP acting alone under the conditions identified in this Paragraph. Prior to seeking termination, BPP must have completed and satisfied all of the following requirements of this Consent Decree:

a. Installation of control technology systems as specified in this Consent Decree;

b. Compliance with all provisions contained in this Consent Decree; such compliance may be established for specific parts of the Consent Decree in accordance with Paragraphs 216 and 217;

c. Payment of all penalties and other monetary obligations due under the terms of the Consent Decree; unless all penalties and/or other monetary obligations owed to the United States or the State of Indiana are fully paid as of the time of the motion;

d. Satisfaction of Part VII ("Supplemental Environmental Projects and Additional Injunctive Relief");

e. Application for and receipt of permits incorporating the emission limits and standards established under this Consent Decree; and

f. For parts of the Consent Decree for which Certificates of Compliance have not been issued in accordance with Paragraphs 216 and 217, operation for at least one (1) year of each unit in compliance with the emission limits established herein and certification of such compliance for each unit within the first progress report following the conclusion of the compliance period.

220. Termination: Procedure. At such time as BPP believes that it has satisfied the requirements for termination set forth in Paragraph 219, BPP will certify such compliance and completion to the United States and the State of Indiana in accordance with the certification language of Paragraph 216. Unless either the United States or the State of Indiana objects in writing with specific reasons within 120 days of receipt of BPP certification under this Paragraph, the Court may upon motion by BPP order that this Consent Decree be terminated. If either the United States or the State of Indiana objects to the certification by BPP, then the matter will be submitted to the Court for resolution under Part XVI (Retention of Jurisdiction/Dispute Resolution). In such case, BPP will bear the burden of proving that this Consent Decree should be terminated.

221. Optional Provision for Termination of Part V, Sections F and G (Heaters and Boilers). At any time after installation of all controls required by, and operation for one (1) year in compliance with the emission limits established pursuant to,

Part V, Sections F and G, BPP may move for termination of Part V, Sections F and G, as provided in this Paragraph:

a. BPP shall prepare and submit to EPA and IDEM a Certification of Completion as provided in Paragraph 216 covering Part V, Sections F and G.

b. In its Certification, BPP shall certify or demonstrate (as applicable) that it has satisfied the requirements of Paragraphs219.a, 219.b, 219.c, 219.e and 219.f that are applicable to the requirements of Part V, Sections F and G.

i. With respect to the requirement in Paragraph 219.c for the payment of penalties and monetary obligations, BPP shall certify that it has complied with the requirements of Part IX ("Civil Penalty") and Part X, Sections F and G ("Stipulated Penalties").

ii. With respect to the requirement in Paragraph 219.e for the application and receipt of permits incorporating the emission limits and standards established under this Consent Decree, BPP shall include copies of the relevant portions of all applicable permits as required by Part V, Section P ("Incorporation of Consent Decree Requirements into Federally Enforceable Permits").

c. EPA shall review and respond to BPP's Certification of Completion for Part V, Sections F and G as provided in Paragraph 217. If EPA concludes that the requirements of Part V, Sections F and G have been completed, EPA shall so notify BPP in lieu of certifying pursuant to Paragraph 217.b, and the Parties shall proceed to terminate Part V, Sections F and G as provided in Paragraph220.

d. <u>Certification of Completion</u>: <u>No Impediment to Stipulated Penalty Demand</u>. Nothing in this Paragraph will preclude the United States from seeking stipulated penalties for a violation of any of the requirements of Part V, Sections F or G regardless of whether a Certification of Completion has been issued under Subparagraph 221.c. In addition, no other provision of this Consent Decree may be terminated pursuant to this Paragraph.

222. Each of the undersigned representatives certifies that she or he is fully authorized to enter into this Consent Decree on behalf of the applicable Party, and to execute and to bind such Party to this Consent Decree.

## XVIII. INTEGRATION

223. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in the Consent Decree and supersedes all prior agreements and understandings, whether oral or written, concerning the settlement embodied herein. No other document, nor any representation, inducement, agreement, understanding, or promise, constitutes any part of this Consent Decree or the settlement it represents, nor shall it be used in construing the terms of this Consent Decree. Headings and Summaries in this Consent Decree are provided for convenience only and shall not affect the substance of any provision.

## XIX. SIGNATORIES

224. Each of the undersigned representatives certifies that she or he is fully authorized to enter into this Consent Decree on behalf of the applicable Party, and to execute and to bind such Party to this Consent Decree.

Dated and entered this _______ day of ________________, 2012.

______________________________
UNITED STATES DISTRICT JUDGE

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR PLAINTIFF THE UNITED STATES OF AMERICA:**

Date: 5/11/12

IGNACIA S. MORENO
Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice

Date: 5/16/12

SUSAN AKERS
Senior Attorney
Environmental Enforcement Section
Environment and Natural Resources Division
United States Department of Justice
P.O. Box 7611
Washington, DC 20044-7611

Date: 5/16/12

STEVEN D. SHERMER
Trial Attorney
Environment and Natural Resources Division
United States Department of Justice

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY:**

Date: 3/28/12

Cynthia Giles

CYNTHIA GILES
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, D.C. 20460

Date: 3/16/12

Pamela J. Mazakas

PAMELA J. MAZAKAS
Acting Director, Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, D.C. 20460

Date: 3.15.12

JOHN FOGARTY
Associate Director, Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, D.C. 20460

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, REGION 5:**

Date: May 10, 2012

SUSAN HEDMAN
US EPA Region 5
Ralph Metcalfe Federal Building
77 West Jackson Blvd.
Chicago, IL 60604-3590

Date: May 2, 2012

Robert A. Kaplan
ROBERT A. KAPLAN
Regional Counsel
US EPA Region 5
Ralph Metcalfe Federal Building
77 West Jackson Blvd.
Chicago, IL 60604-3590

Date: May 2, 2012

WILLIAM WAGNER
US EPA Region 5
Ralph Metcalfe Federal Building
77 West Jackson Blvd.
Chicago, IL 60604-3590

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR THE STATE OF INDIANA:**

GREGORY F. ZOELLER
Indiana Attorney General

Date: May 14, 2012

PATRICIA ORLOFF ERDMANN
Chief Counsel of Litigation
Office of the Attorney General
Indiana Government Center South, 5th Floor
402 West Washington Street
Indianapolis, Indiana 46204

Date: 27 April 2012

Valerie Tachtiris
VALERIE TACHTIRIS
Deputy Attorney General
Office of the Attorney General
Environmental Division

Date: APRIL 27, 2012

THOMAS W. EASTERLY
Commissioner
Indiana Department of Environmental Management

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR PLAINTIFF-INTERVENOR THE SIERRA CLUB:**

Date: 3-20-12

DAVID MAIDENBERG
Director, Sierra Club Hoosier Chapter

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR PLAINTIFF-INTERVENOR SAVE THE DUNES CONSERVATION FUND, INC., D/B/A SAVE THE DUNES:**

Nicole Barker

Date: 2/27/12

NICOLE BARKER
Executive Director
Save the Dunes

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR PLAINTIFF-INTERVENOR THE NATURAL RESOURCES DEFENSE COUNCIL:**

Date: _____2/27/12__________________

____________________________________
HENRY HENDERSON
Director, Midwest Program
Natural Resources Defense Council

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR PLAINTIFF-INTERVENOR THE ENVIRONMENTAL INTEGRITY PROJECT:**

Date: 03/16/2012

Eric Schaeffer

ERIC SCHAEFFER
Executive Director
Environmental Integrity Project

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR PLAINTIFF-INTERVENOR THE ENVIRONMENTAL LAW AND POLICY CENTER:**

Date: 3/15/2012

Howard Learner

HOWARD A. LEARNER
President and Executive Director
Environmental Law and Policy Center

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR PLAINTIFF-INTERVENOR SUSAN ELEUTERIO:**

Date: 3/19/12

SUSAN ELEUTERIO

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR PLAINTIFF-INTERVENOR TOM TSOURLIS:**

Date: 03-19-12

Tom Tsourlis

TOM TSOURLIS

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

**FOR DEFENDANT BP PRODUCTS NORTH AMERICA INC.:**

Date: March 02, 2012

STEVE R. CORNELL
President
BP Products North America Inc.

Date: March 5, 2012

JAMES A. NOLAN, Jr., ESQ.
Managing Counsel-HSSE
BP America, Inc.

Date: Feb. 27, 2012

JOEL M. GROSS, ESQ.
Arnold & Porter LLP

Date: February 28, 2012

WILLIAM L. PATBERG, ESQ.
Shumaker, Loop & Kendrick, LLP

**ATTORNEYS FOR BP PRODUCTS NORTH AMERICA INC.**

Subject to the notice and comment provisions of 28 C.F.R. § 50.7, THE UNDERSIGNED PARTIES enter into this Consent Decree entered in the matter of *United States, et al., v. BP Products North America* (N.D. Ind.).

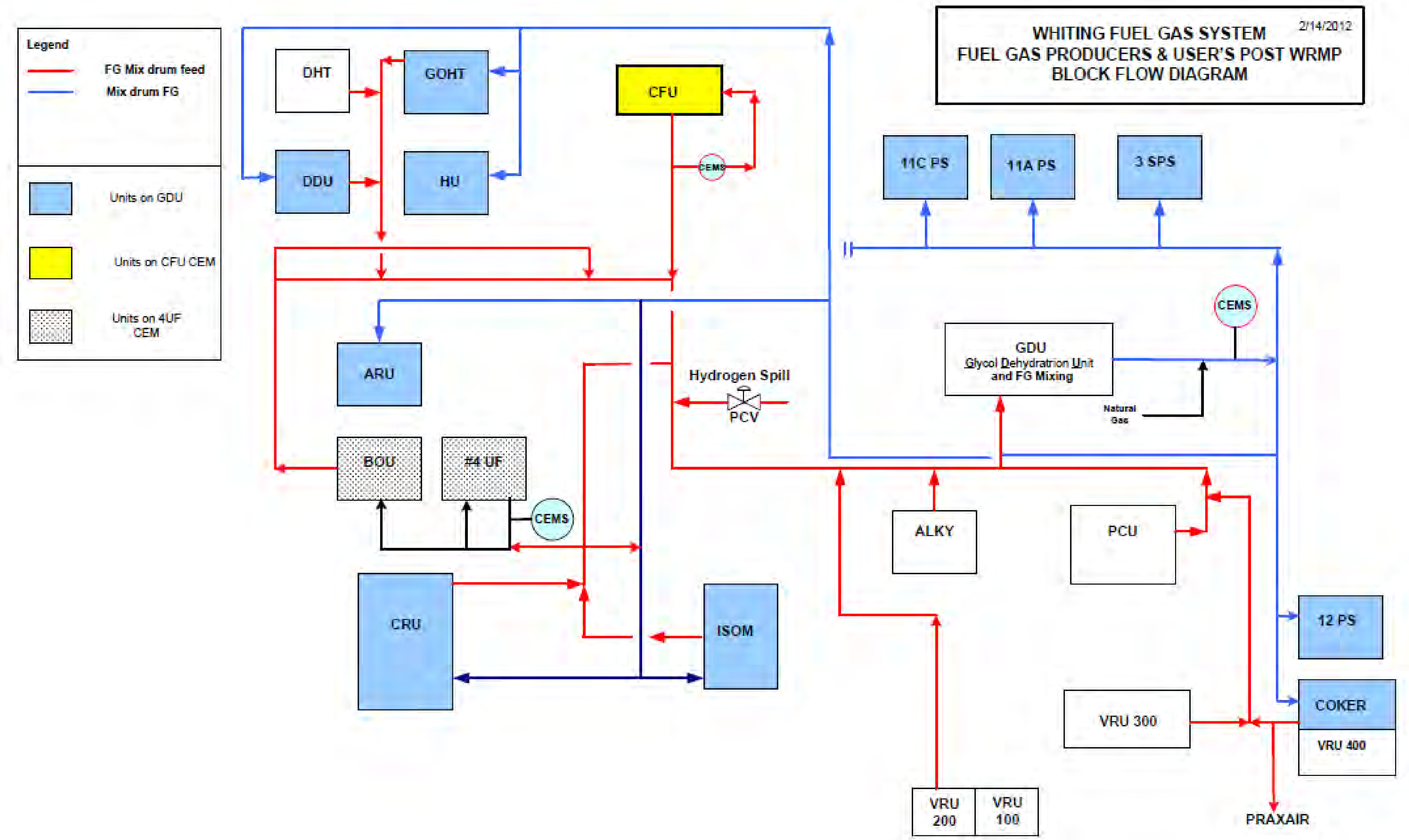
**FOR PLAINTIFF-INTERVENOR THE HOOSIER ENVIRONMENTAL COUNCIL:**

Date: March 15, 2012

JESSE KHARBANDA
Executive Director
Hoosier Environmental Council

# APPENDIX A

## LOCATION OF FUEL GAS SULFUR MONITORS



# <u>APPENDIX B</u>
# ENHANCED LDAR PROGRAM

**<u>Definitions:</u>**

1. The definitions set forth in the Consent Decree shall apply for purposes of this Appendix B. For purposes of this Appendix B to the Consent Decree, the following definitions shall also apply:

   a. "Certified Low-Leaking Valves" shall mean valves for which a manufacturer has issued either: (i) a written guarantee that the valve will not leak above 100 parts per million (ppm) for five years; or (ii) a written guarantee, certification or equivalent documentation that the valve has been tested pursuant to generally-accepted good engineering practices and has been found to be leaking at no greater than 100 ppm.

   b. "Certified Low-Leaking Valve Packing Technology" shall mean valve packing technology for which a manufacturer has issued either: (i) a written guarantee that the valve packing technology will not leak above 100 ppm for five years; or (ii) a written guarantee, certification or equivalent documentation that the valve packing technology has been tested pursuant to generally-accepted good engineering practices and has been found to be leaking at no greater than 100 ppm.

   c. "Covered Equipment" shall mean all pumps and valves, in light liquid, heavy liquid, or gas/vapor service in all Covered Process Units.

   d. "Covered Process Units" shall mean any process unit that is, or under the terms of this Consent Decree becomes, subject to the equipment leak provisions of 40 C.F.R. Part 60, Subpart GGGa.

   e. "DOR" shall mean Delay of Repair.

   f. "ELP" shall mean the Enhanced Leak Detection and Repair Program specified in this Appendix B.

   g. "Equipment" shall mean any equipment as defined in 40 C.F.R. § 60.591a.

   h. "LDAR" shall mean Leak Detection and Repair.

   i. "LDAR Audit Commencement Date" or "Commencement of an LDAR Audit" shall mean the first day of the on-site inspection that accompanies an LDAR audit.

j. "LDAR Audit Completion Date" or "Completion of an LDAR Audit" shall mean one hundred twenty (120) calendar Days after the LDAR Audit Commencement Date.

k. "Maintenance Shutdown" shall mean a shutdown of a Covered Process Unit that lasts longer than 30 calendar days.

l. "Method 21" shall mean the test method found at 40 C.F.R. Part 60, Appendix A, Method 21.

m. "Repair Verification Monitoring" shall mean the utilization of monitoring (or another method that indicates the relative size of the leak) by no later than the end of the next calendar day of each attempt at repair of a leaking piece of Covered Equipment to achieve the best repair/lowest emission rate possible.

n. "Screening Value" shall mean the highest emission level that is recorded at each piece of Covered Equipment as it is monitored in compliance with Method 21.

**<u>Part A: General</u>**

2. The requirements of the ELP shall apply to all Covered Equipment. In addition, the requirements of Paragraphs 3, 23, 26.a., 26.b., 27-28, 31 (except the non-federally enforceable provisions of Paragraph 31.c), and 32 of this Appendix shall also apply to all Equipment at the Whiting Refinery that is regulated under any federal, state, or local LDAR program. The requirements of this ELP are in addition to, and not in lieu of, the requirements of any federal, state or local LDAR regulation that may be applicable to a piece of Covered Equipment. If there is a conflict between a federal, state or local LDAR regulation and this ELP, BPP shall follow whichever regulation is more stringent.

3. By no later than sixty (60) Days after the Date of Entry, BPP shall develop a written facility-wide LDAR Program that describes: (i) its facility-wide LDAR program (*e.g.*, applicability of regulations to process units and/or specific Equipment; leak definitions; monitoring frequencies); (ii) a tracking program (*e.g.*, Management of Change) that ensures that new pieces of Equipment added to the Whiting Refinery for any reason are integrated into the LDAR program and that pieces of Equipment that are taken out of service are removed from the LDAR program; (iii) the roles and responsibilities of all employee and contractor personnel assigned to LDAR functions at the Whiting Refinery; (iv) how the number of personnel dedicated to LDAR functions is sufficient to satisfy the requirements of the LDAR program; and (v) how the Whiting Refinery plans to implement this ELP. BPP shall review this document on an

annual basis and update it as needed by no later than December 31 of each year, beginning December 31, 2012.

**Part B: Monitoring Frequency**

4. By no later than the Date of Entry, for all Covered Equipment, BPP shall comply with the monitoring frequency for valves as required by 40 C.F.R. § 60.482-7a, 40 C.F.R. § 60.482-4a, 40 C.F.R. § 60.482-8a, and 40 C.F.R. § 60.482-10a, except as provided in 40 C.F.R. § 60.482-1a, and for pumps as required by 40 C.F.R. § 60.482-2a. and 40 C.F.R. § 60.482-8a.

5. Alternative Standards for Valves – Skip Period Leak Detection and Repair. BPP may elect to comply with the skip period monitoring requirements set forth in 40 C.F.R. § 60.483-2a, if applicable.

**Part C: Monitoring Methods and Equipment**

6. Method 21 and Alternative Work Practice Monitoring.

a. Except as provided in subparagraph 6.b., by no later than the Date of Entry, for all Covered Equipment, BPP shall comply with Method 21 in performing LDAR monitoring, using a Toxic Vapor Analyzer 1000B Flame Ionization Detector (FID) attached to a data logger, or equivalent equipment, which directly electronically records the Screening Value detected at each piece of Covered Equipment, the date and time that each Screening Value is taken, and the identification numbers of the monitoring instrument and technician. BPP shall transfer this monitoring data to an electronic database on at least a weekly basis for recordkeeping purposes. Notwithstanding the foregoing, BPP may use paper logs where necessary or more feasible (*e.g.*, small rounds, re-monitoring, or when data loggers are not available or broken). Any manually recorded monitoring data shall be transferred to the electronic database within 7 days of monitoring.

b. Alternative Work Practice.

(i) From the Date of Entry, BPP may utilize the Alternative Work Practice as defined at 40 C.F.R. 60.18(g) ("the AWP") for monitoring Equipment that meets the "difficult to monitor" criteria set out at 40 C.F.R. § 60.482-7a(h)(1).

(ii) No sooner than three (3) years from the Date of Entry, BPP may submit a request for review and approval of an AWP for LDAR monitoring of all Covered Equipment. Such request shall include a protocol that, at a minimum, addresses the following operational criteria:

(A) calibration procedures;

(B) startup (*i.e.*, warming-up the Optical Gas Imaging (OGI) Instrument)/shutdown procedures;

(C) video recording and storage;

(D) site-specific impact of weather conditions (*e.g.*, wind speed, temperature, and visibility);

(E) maintenance of the OGI Instrument;

(F) certification of personnel to use the OGI instrument;

(G) minimum number of hours of field use by certified personnel prior to certified personnel performing compliance monitoring; and

(H) identification of process unit(s) where certified personnel may monitor with an OGI instrument.

If such request is approved by EPA, BPP may utilize the AWP for monitoring all Covered Equipment.

7. BPP shall conduct all calibrations of LDAR monitoring equipment as required by Subpart GGGa in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21, prior to each time LDAR monitoring equipment is placed into service before each monitoring shift or is restarted during a monitoring shift, except as provided below. BPP shall conduct calibration drift assessment rechecks of the LDAR monitoring equipment at the end of each monitoring shift and prior to each time LDAR monitoring equipment is turned off during each monitoring shift, except when LDAR monitoring equipment is unable to function such that the calibration drift assessment recheck cannot be performed before the LDAR monitoring equipment turns off. BPP is not required to conduct a calibration drift assessment re-check during the same monitoring shift in the event of a “flame-out” of the instrument if the instrument can be immediately re-ignited. The calibration drift assessment shall be conducted using calibration gas as provided in 40 C.F.R. § 60.485a(b)(1) with a concentration approximately equal to the applicable internal leak definition. If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous calibration, BPP shall re-monitor all components that had a reading greater than 250 ppm. BPP shall retain all calibration records for at least one year, or as

otherwise required by any federal state or local law, whichever is most stringent.

**Part D: Leak Detection and Repair Action Levels**

8. To the extent required by 40 C.F.R. Part 60, Subpart GGGa, BPP shall identify leaks through Method 21 monitoring (or the AWP pursuant to Paragraph 6.b.), and audio, visual, and olfactory sensing inspections.

9. Leak Definitions and Repairs for Valves and Pumps.

   a. By no later than the Date of Entry, for each leak detected at or above the leak definition for valves defined at 40 C.F.R. § 60.482-7a(b), BPP shall perform repairs in accordance with Paragraphs 11 - 16 of this Appendix.

   b. By no later than the Date of Entry, for each leak detected at or above the leak definition for pumps defined at 40 C.F.R. §60.482-2a(b)(1)(ii), BPP shall perform repairs in accordance with Paragraphs 12 - 16 of this Appendix.

10. By no later than the Date of Entry, for all Covered Equipment, at any time, including outside of periodic monitoring, that a leak is detected through audio, visual, or olfactory sensing, BPP must repair the piece of Covered Equipment in accordance with 40 C.F.R. Part 60, Subpart GGGa, and with Paragraphs 12 - 16 of this Appendix.

**Part E: Leak Repairs**

11. BPP shall make an "initial attempt" at repair on any valve that has a reading greater than 100 ppm of VOCs, excluding control valves and other valves that LDAR personnel are not authorized to repair.

12. For each leak subject to Paragraph 9 of this Appendix, by no later than five (5) Days after detecting a leak, BPP shall perform a first attempt at repair. By no later than fifteen (15) Days after detection, BPP shall perform a final attempt at repair or may place the valve or pump covered by Paragraph 9 on the Delay of Repair list provided that BPP has complied with 40 C.F.R. Part 60, Subpart GGGa and with the requirements of Paragraphs 13 – 15 and 17 of this Appendix.

13. For each attempt at repair as set forth in paragraphs 11 and 12 of this Appendix, BPP shall perform Repair Verification Monitoring.

14. Drill-and-Tap Repairs.

a. Except as provided in Subparagraph 14.b, for leaking valves (other than control valves), when other repair attempts have failed to reduce emissions below the applicable leak definition and BPP is not able to remove the leaking valve from service, BPP shall attempt at least one drill-and-tap repair (with a second injection of sealant if the first injection is unsuccessful at repairing the leak) before placing the valve on the DOR list.

b. Drill-and-tap is not required when there is a major safety, mechanical, product quality, or environmental issue with repairing the valve using the drill-and-tap method, in which case, BPP shall document the reason(s) why any drill-and-tap attempt was not performed prior to placing any valve on the DOR list.

15. For each leak, BPP shall record the following information: the date of all repair attempts; the repair methods used during each repair attempt; the date, time and Screening Values for all re-monitoring events; and, if relevant, the information required under Paragraph 14 and 17 of this Appendix for Covered Equipment placed on the DOR list.

16. Nothing in Paragraphs 12 - 15 of this Appendix is intended to prevent BPP from taking a leaking piece of Covered Equipment out of service; provided however, that prior to placing the leaking piece of Covered Equipment back in service, BPP must repair the leak or must comply with the requirements of Part F of this Appendix (Delay of Repair) to place the piece of Covered Equipment on the DOR list.

**Part F: Delay of Repair**

17. By no later than the Date of Entry, for all Covered Equipment placed on the DOR list, BPP shall require the following:

a. Sign-off from the plant manager, a corporate official responsible for environmental management and compliance, a corporate official responsible for plant engineering, an operations manager, or an area superintendent that the piece of Covered Equipment is technically infeasible to repair without a process unit shutdown;

b. Periodic monitoring, at the frequency required for other pieces of Covered Equipment of that type in the process unit, of the Covered Equipment placed on the DOR list;

c. No more than 0.10% of all valves may be on the DOR list at any one time. If a valve (i) is isolated and taken out of VOC and/or HAP service at the same time it is placed on the DOR list and is repacked with Certified Low-Leaking Valve Packing Technology or is replaced with Certified Low-Leaking Valves before it is placed back into VOC and/or HAP service, or (ii) is repacked with Certified Low-Leaking Valve Packing Technology or replaced with Certified Low-Leaking Valves at the next Maintenance Shutdown, such valve shall not be included in computing the applicable percentage limitation of valves that may be on the DOR list at any one time; and

d. Covered Equipment may be removed from the DOR list if is monitored at the frequency required for other pieces of Covered Equipment of that type in the process unit for two successive monitoring periods without detecting a leak greater than the Leak Definition as set forth in 40 C.F.R. Part 60, Subpart GGGa for that type of Covered Equipment.

**Part G: Valve Replacement/Improvement Program**

18. Commencing no later than the Date of Entry, and continuing until termination, BPP shall implement the program set forth in Paragraphs 19 through 22 of this Appendix to replace and/or improve the emissions performance of the valves in each Covered Process Unit.

19. Valves.

a. By no later than the Date of Entry:

(i) BPP shall implement modified purchasing procedures that evaluate the availability of valves and valve packing that meet the requirements for a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology at the time that the valves and/or valve packing is acquired.

(ii) Except as provided in Paragraph 20, BPP shall install valve packing material that meets the requirements for Certified Low-Leaking Valve Packing Technology whenever repacking any valve in gas/vapor or light liquid VOC service in a Covered Process Unit.

b. By no later than 90 days after the Date of Entry (except as provided in Paragraph 20), BPP shall ensure that each new valve in gas/vapor or light liquid VOC service that it purchases for use in any Covered Process Unit either is a Certified Low-Leaking Valve or is fitted with Certified Low-Leaking Valve Packing Technology.

c. By no later than the dates specified below (except as provided in Paragraph 20), BPP shall ensure that each new valve in gas/vapor or light liquid VOC service that it installs in any Covered Process Unit either is a Certified Low-Leaking Valve or is fitted with Certified Low-Leaking Valve Packing Technology:

(i) For all Process Units other than the new Coker and the new GOHT, by no later than 18 months after Date of Entry; and

(ii) For the new Coker and the new GOHT, by no later than 24 months after Date of Entry.

d. Replacing or Repacking Existing Valves that have Screening Values At or Above 5,000 ppm. Except as provided in Paragraph 20, for each Existing Valve in each Covered Process Unit that has a Screening Value at or above 5,000 ppm during any monitoring event, BPP shall replace or repack the Existing Valve with a Certified Low-Leaking Valve or with Certified Low-Leaking Valve Packing Technology. BPP shall undertake this replacement or repacking by no later than 30 days after the monitoring event that triggers the replacement or repacking requirement, unless the replacement or repacking requires a process unit shutdown. If the replacement or repacking requires a process unit shutdown, BPP shall undertake the replacement or repacking during the Maintenance Shutdown that follows the monitoring event that triggers the requirement to replace or repack the valve. If BPP completes the replacement or repacking within 30 days of detecting the leak, BPP shall not be required to comply with Part E of this Appendix. If BPP does not complete the replacement or repacking within 30 days, or if, at the time of the leak detection, BPP reasonably can anticipate that it might not be able to complete the replacement or repacking within 30 days, BPP shall comply with all applicable requirements of Part E of this Appendix.

20. Commercial Unavailability of a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology.

a. BPP shall not be required to utilize a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology to replace or repack a valve if a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology is commercially unavailable in accordance with the provisions in Part O of this Appendix. Prior to claiming this commercial unavailability exemption, BPP must contact a reasonable number of vendors of valves and obtain a written representation or equivalent documentation from each vendor that the particular valve that BPP needs is commercially unavailable either as a Certified Low-Leaking Valve or with Certified Low-Leaking Valve Packing Technology. In the Compliance Status Reports due under Part N of this Appendix, BPP shall: (i) identify each valve for which it could not comply with the requirement to replace or repack the valve with a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology; (ii) identify the vendors it contacted to determine the unavailability of such a Valve or Packing Technology; and (iii) include the written representations or documentation that BPP secured from each vendor regarding the unavailability.

b. Ongoing Assessment of Availability. BPP may use a prior determination of Commercial Unavailability of a valve or valve packing pursuant to this Paragraph and Part O of this Appendix for a subsequent Commercial Unavailability claim for the same valve or valve packing (or valve or valve packing in the same or similar service), provided that the previous determination was completed within the preceding 12-month period. After one year, BPP must conduct a new assessment of the availability of a valve or valve packing meeting Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology requirements.

21. Records of Certified Low-Leaking Valves and Certified Low-Leaking Valve Packing Technology. Prior to installing any Certified Low-Leaking Valves or Certified Low-Leaking Valve Packing Technology, BPP shall secure from each manufacturer documentation that demonstrates that the proposed valve or packing technology meets the definition of "Certified Low-Leaking Valve" and/or "Certified Low-Leaking Valve Packing Technology." BPP shall retain that documentation for the duration of this Consent Decree and make it available upon request.

22. Valve Replacement/Improvement Report. In each Compliance Status Report due under Part N of this Appendix, BPP shall include a separate section in the Report that: (i) describes the actions it took to comply with this Part G, including identifying each valve that was replaced or upgraded; and (ii) identifies the schedule for any future replacements or upgrades.

**Part H: Management of Change**

23. Management of Change: For each Management of Change process or analysis, BPP shall ensure that each piece of Equipment added to the Whiting Refinery or removed from the Whiting Refinery for any reason is evaluated to determine if it is or was subject to LDAR requirements and that such pieces of Equipment are integrated into or removed from the LDAR program.

**Part I: Training**

24. By no later than six (6) months after the Date of Entry, BPP shall have ensured that all employees and contractors responsible for LDAR monitoring, maintenance of LDAR monitoring equipment, LDAR repairs, and/or any other duties generated by the LDAR program have completed training on all aspects of LDAR that are relevant to the person's duties. By that same time, BPP shall develop a training protocol to ensure that refresher training is performed once per calendar year and that new personnel are sufficiently trained prior to any involvement in the LDAR program.

**<u>Part J: Quality Assurance ("QA")/Quality Control ("QC")</u>**

25. <u>Daily Certification by Monitoring Technicians</u>. Commencing no later than the Date of Entry, on each day that monitoring occurs, at the end of such monitoring day to the extent practical but in no case later than the next work day for the monitoring technician, BPP shall ensure that each monitoring technician certifies that the data collected represents the monitoring performed for that day by requiring the monitoring technician to sign a form that includes the following certification:

> On [insert date], I reviewed the monitoring data that I collected on [insert date] and to the best of my knowledge and belief, the data accurately represents the monitoring I performed today.

In lieu of a form for each technician for each day of monitoring, a log sheet may be created that includes the certification that the monitoring technicians would date and sign each day that the technician collects data.

26. Commencing by no later than the first full calendar quarter after the Date of Entry, during each calendar quarter, at unannounced times, an LDAR-trained employee or contractor of BPP, who does not serve as an LDAR monitoring technician on a routine basis, shall undertake the following:

a. review Management of Change documentation for the previous calendar quarter, and conduct process unit walk-throughs to determine whether all pieces of Equipment identified in the previous calendar quarter's Management of Change documentation as being subject to the LDAR program are included in the LDAR database and are properly tagged;

b. during the process unit walk-throughs required by subparagraph 26.a., and during such additional walk-throughs as may be necessary to assure that all Covered Process Units are reviewed at least once per year, conduct spot checks of Equipment to verify that the Equipment checked is included in the LDAR database and is properly tagged;

c. review the LDAR database to:

(i) verify that Covered Equipment was monitored at the appropriate frequency;

(ii) verify that proper documentation and sign-offs have been recorded for all Covered Equipment placed on the shutdown or DOR list;

(iii) ensure that repairs have been performed within the required timeframe;

(iv) review monitoring data and Covered Equipment counts (*e.g.*, number of pieces of Covered Equipment monitored per Day) for feasibility and unusual trends;

(v) verify that proper calibration records and monitoring instrument maintenance information are stored and maintained;

d. conduct spot checks of LDAR program records to verify that those records are maintained as required; and

e. observe each LDAR monitoring technician in the field to ensure monitoring is being conducted as required.

BPP shall correct any deficiencies detected or observed as soon as practicable. BPP shall maintain a log that: (i) records the date and time that the reviews, verifications, and observations required by this Paragraph were undertaken; and (ii) describes the nature and timing of any corrective actions taken.

**<u>Part K: LDAR Audits and Corrective Action</u>**

27. BPP shall conduct LDAR audits pursuant to the schedule in Paragraph 28 and the requirements of Paragraph 29 of this Appendix. BPP shall retain a third-party with experience in conducting LDAR audits to conduct no less than the initial audit and follow-up audits every two (2) years until termination of the Consent Decree. To perform the third-party audit, BPP shall select a different company than its regular LDAR contractor. At its discretion, in years in which BPP is not required to retain a third-party auditor, BPP may conduct the audit internally by using its own personnel, provided that the personnel BPP uses are not employed at the Whiting Refinery but rather are employed at a facility that currently uses Certified Low-Leaking Valve and/or Certified Low-Leaking Valve Packing Technology. All such internal audits must be conducted by personnel familiar with regulatory LDAR requirements and this ELP.

28. <u>Internal LDAR Audits</u>. Until termination of this Consent Decree, BPP shall ensure that an LDAR audit at the Whiting Refinery is conducted by an independent contractor with expertise in LDAR program requirements to perform a third party audit for all regulatory LDAR requirements and this ELP every twenty-four (24) months in accordance with the following schedule: for the first LDAR audit at the Whiting Refinery, the LDAR Audit Commencement Date shall be no later than the second calendar quarter after the Date of Entry. For each subsequent LDAR audit, the LDAR Audit Completion Date shall occur within the same calendar quarter that the first LDAR Audit Completion Date occurred.

29. Each LDAR audit shall include but not be limited to reviewing compliance with all applicable regulations, reviewing and/or verifying the same items that are required to be reviewed and/or verified in Paragraph 26 of this Appendix, and performing the following activities for Covered Equipment:

a. <u>Calculating a Comparative Monitoring Audit Leak Percentage</u>. Covered Equipment, excluding pumps and valves in heavy liquid service, shall be monitored to calculate a leak percentage for each Covered Process Unit broken down by Covered Equipment type (*i.e.*, valves and pumps). The monitoring that takes place during the audit shall be called "comparative monitoring" and the leak percentages derived from the comparative monitoring shall be called the "Comparative Monitoring Audit Leak Percentage." Until termination of this Consent Decree, BPP shall conduct a comparative monitoring audit pursuant to this Paragraph during each LDAR audit. Each Covered Process Unit at the Whiting Refinery that is not the subject of the current audit shall have a comparative monitoring audit at least once before a previously-audited Covered Process Unit is audited again.

b. <u>Calculating the Historic, Average Leak Percentage from Prior Periodic Monitoring Events</u>. For the Covered Process Unit that is audited, the historic average leak percentage from prior monitoring events, broken down by Covered Equipment type (*i.e.*, valves and pumps) shall be calculated. The following number of complete monitoring periods immediately preceding the comparative monitoring audit shall be used for this purpose: valves - 2 periods; and pumps - 12 periods.

c. <u>Calculating the Comparative Monitoring Leak Ratio</u>. For the Covered Process Unit that is audited, the ratio of the comparative monitoring audit leak percentage from Paragraph 29.a to the historic average leak percentage from Paragraph 29.b shall be calculated. If a calculated ratio yields an infinite result, BPP shall assume one leaking piece of

Covered Equipment was found in the process unit through its routine monitoring during the 12-month period before the audit, and the ratio shall be recalculated.

In addition to these items, LDAR audits after the first audit shall include reviewing the Whiting Refinery's compliance with this ELP.

30. When More Frequent Periodic Monitoring is Required. If a comparative monitoring audit leak percentage calculated pursuant to Paragraph 29.a triggers a more frequent monitoring schedule under any applicable federal, state, or local law or regulation than the frequencies listed in Paragraphs 4, 5 or 6 of Part B of this Appendix for the equipment type in that Covered Process Unit, BPP shall monitor the affected type of Covered Equipment at the greater frequency unless and until less frequent monitoring is again allowed under the specific federal, state, or local law or regulation. At no time may BPP monitor at intervals less frequently than those in the applicable Paragraph in Part B of this Appendix.

31. Corrective Action Plan.

a. Requirements of a CAP. By no later than 30 days after each LDAR Audit Completion Date, BPP shall develop a preliminary corrective action plan ("CAP") if the results of an LDAR audit identify any deficiencies or if the Comparative Monitoring Leak Ratio calculated pursuant to Subparagraph 29.c is 3.0 or higher. The CAP shall describe the actions that BPP shall take to correct the deficiencies and/or the systemic causes of a Comparative Monitoring Leak Ratio that is 3.0 or higher. The CAP also shall include a schedule by which those actions shall be undertaken. BPP shall complete each corrective action as expeditiously as possible with the goal of completing each action within 90 days after the LDAR Audit Completion Date. If any action is not completed or is not expected to be completed within 90 days after the LDAR Audit Completion Date, BPP shall explain the reasons in the final CAP to be submitted under Subparagraph 31.b, together with a proposed schedule for completion of the action(s) as expeditiously as practicable.

b. Submissions of the CAP to EPA. By no later than 120 days after the LDAR Audit Completion Date, BPP shall submit the final CAP to EPA, together with a certification of the completion of corrective action(s). For any corrective actions requiring more than 90 days to complete, BPP shall include an explanation together with a proposed schedule for completion as expeditiously as practicable.

c. Approval/Disapproval of All or Parts of a CAP.

i. Unless within 60 days after receipt of the CAP, EPA disapproves all or part of a CAP's proposed actions and/or schedules, the CAP shall be deemed approved.

ii. By no later than 60 days after receipt of BPP's CAP, EPA may disapprove any or all aspects of the CAP. Each item that is not specifically disapproved shall be deemed approved. Except for good cause, EPA may not disapprove any action within the CAP that already has been completed. Within 45 days of receipt of any disapproval from EPA, BPP shall submit a revised CAP that addresses the deficiencies that EPA identified. BPP shall implement the revised CAP either pursuant to the schedule that EPA proposed, or, if EPA did not so specify, as expeditiously as practicable.

iii. A dispute arising with respect to any aspect of a CAP shall be resolved in accordance with the dispute resolution provisions of this Decree.

**Part L: Certification of Compliance**

32. Within 180 days after the initial LDAR Audit Completion Date, BPP shall submit a certification to EPA and IDEM that, to the best of the certifier's knowledge and belief after reasonable inquiry: (i) the Whiting Refinery is in compliance with all applicable LDAR regulations; (ii) BPP has completed all corrective actions, if applicable, or is in the process of completing all corrective actions pursuant to a CAP; and (iii) all Equipment at the Whiting Refinery that is regulated under any federal, state, or local leak detection program has been identified and included in the Whiting Refinery's LDAR program.

**Part M: Recordkeeping**

33. BPP shall keep all records, including copies of all LDAR audits, to document compliance with the requirements of this ELP in accordance with Section VIII (Reporting and Recordkeeping) of this Consent Decree. All monitoring data, leak repair data, training records, and audits will be retained for five (5) years, except for the calibration records (including calibration drift assessments) which will be retained for one (1) year. Upon request by EPA, BPP shall make all such documents available to EPA and shall provide, in their original electronic format, all LDAR monitoring data generated during the life of this Consent Decree.

**Part N: Reporting**

34. Compliance Status Reports. On the dates and for the time periods set forth in Paragraph 35 of this Appendix, BPP shall submit, in the manner set forth in Section XVI (General Provisions) of the Consent Decree, a compliance status report regarding compliance with this ELP. The compliance status report shall include the following information:

a. The number of personnel assigned to LDAR functions at the Whiting Refinery and the percentage of time each person dedicated to performing his/her LDAR functions;

b. An identification and description of any non-compliance with the requirements of this Appendix;

c. An identification of any problems encountered in complying with the requirements of this Appendix;

d. The information required in Paragraph 20 of this Appendix;

e. A description of any LDAR training required in accordance with Part I of this Appendix;

f. Any deviations identified in the QA/QC performed under Part J of this Appendix B, as well as any corrective actions taken under that Part;

g. A summary of LDAR audit results including specifically identifying all deficiencies; and

h. The status of all actions under any CAP that was submitted pursuant to Part K of this Appendix during the reporting period.

35. Due Dates. The first compliance status report shall be due thirty-one (31) days after the first full half-year after the Date of Entry (*i.e.*, either: (i) January 31 of the year after the Date of Entry, if the Date of Entry is between January 1 and June 30 of the preceding year; or (ii) July 31 of the year after the Date of Entry, if the Date of Entry is between July 1 and December 31). The initial report shall cover the period between the Date of Entry and the first full half year after the Date of Entry (a "half year" runs between January 1 and June 30 and between July 1 and December 31). Until termination of this Decree, each subsequent report will be due on the same date in the following year and shall cover the prior two half years (*i.e.*, either January 1 to December 31 or July 1 to June 30).

36. Each compliance status report submitted under this Part shall be signed by the plant manager, a corporate official responsible for environmental management and compliance, or a corporate official responsible for plant engineering management, and shall include the following certification:

I certify under penalty of law that I have examined and am familiar with the information in the enclosed document(s), including all attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are, to the best of my knowledge and belief, true and complete. I am aware that there are significant penalties for knowingly submitting false statements and information, including the possibility of fines or imprisonment pursuant to Section 113(c)(3) of the Clean Air Act and 18 U.S.C. Sections 1001 and 1341.

**Part O: Process and Factors for "Commercial Unavailability" of Low-Leaking Valve or Packing Technology**

Summary: This Part outlines a process to be followed and factors to be taken into consideration to establish that a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology is not "commercially available" pursuant to Paragraph 20 of this Appendix. Factors and procedures other than those identified in this Part may also be utilized to establish that a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology is not commercially available.

37. Factors. The following factors shall be taken in to account for determining the availability of safe and suitable Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technologies:

(1) Valve type;
(2) Valve service and operating conditions;
(3) Type of refinery process equipment in which the valve is used;
(4) Seal performance;
(5) Service life;
(6) Packing friction;
(7) Temperature and pressure limitations; and
(8) Retrofit applications (*e.g.*, re-piping or space limitations).

The following factors may also be relevant for consideration, depending on the process unit or equipment in use at the refinery:

(9) Valve or valve packing specifications identified by the licensor of the process unit or equipment in use at the refinery (including components that are part of a design package by a specialty-equipment provider as part of a larger process unit); or
(10) Valve or valve packing vendor or manufacturer recommendations for the relevant refinery unit and/or process unit components.

38. Process. The following procedure shall be followed for determining the availability of a Certified Low-Leaking Valve or Certified Valve Packing Technology:

a. BPP must contact a reasonable number of vendors of valves and valve packing technologies, taking into account the relevant factors identified above, prior to asserting a claim that Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology is not commercially available.

i. For purposes of this Consent Decree, a reasonable number of vendors shall mean at least three vendors of valves and three vendors of valve packing technologies;

ii. If fewer than three vendors of valve or valve packing technologies are contacted, the determination of whether such fewer number is reasonable for purposes of this Consent Decree shall be based on Factors (9) and/or (10) above, or on a demonstration that fewer than three vendors offer valves or valve packing technologies for the service and operating conditions of the valve to be replaced, in consideration of Factors (1) through (8) above, as applicable.

b. BPP shall obtain a written representation from each vendor contacted or equivalent documentation that the valve or valve packing does not meet the specifications for a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology.

c. BPP shall prepare a written report fully explaining the basis for each claim that a valve or valve packing is not commercially available, to include all relevant documentation and other information supporting the claim. Such report shall also identify the commercially-available valve or packing technology that comes closest to meeting the requirements for a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology that is selected and installed by BPP pursuant to Paragraph 19 of this Appendix. Such report shall be included in the Semi-Annual Report required by Section VIII of the Consent Decree, for the period in which the valve or valve packing is replaced.

39. EPA Review of Claim of Commercial Unavailability. Upon discretionary review by EPA of any claim of commercial unavailability, if EPA disagrees that a valve or valve-packing technology is commercially unavailable, EPA shall notify BPP in writing, specifying the valve or valve packing EPA believes to be commercially available and the basis for

its availability for the service and operating conditions of the valve. Following receipt by BPP of EPA's notice, the following shall apply:

a. BPP is not required to retrofit the valve or valve packing for which the unavailability claim was asserted (unless otherwise required to do so pursuant to some other provision of this Consent Decree).

b. EPA's notification shall serve as notice to BPP of EPA's intent that a future claim of commercial unavailability will not be accepted for (a) the valve or valve packing that was the subject of the unavailability claim, or (b) for a valve or valve packing in the same or similar service, taking into account the factors identified in this Appendix. If BPP disagrees with EPA's notification, BPP and EPA may informally discuss the basis for the claim of commercial unavailability. EPA may thereafter revise its notification, if necessary.

c. If BPP makes a subsequent commercial unavailability claim for the same valve or valve packing (or valve or valve packing in the same or similar service) that was the subject of a prior unavailability claim which was not accepted by EPA, and such subsequent claim is also denied by EPA on the same basis as provided in EPA's prior notification, BPP shall retrofit the valve or valve packing with the commercially available valve or valve packing technology at the next unit turnaround.

d. Any disputes concerning EPA's notification to BPP of the commercial availability of a valve or valve packing technology in a particular application pursuant to Paragraph 39.c of this Appendix shall be addressed under the Dispute Resolution provisions in Section XIV of this Consent Decree.

**APPENDIX C**

**BEAVON STRETFORD MONITORING PROCEDURE**

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

AUG 3 0 2006

REPLY TO THE ATTENTION OF:

AE-17J

Linda Wilson
British Petroleum Products North America, Inc.
Whiting Business Unit
2815 Indianapolis Boulevard
Post Office Box 710
Whiting, Indiana 46394

Dear Ms. Wilson:

The United States Environmental Protection Agency (U.S. EPA) is in receipt of your letter dated July 21, 2006, requesting the review of an alternative monitoring plan (AMP) to the New Source Performance Standards for Petroleum Refineries at 40 C.F.R. Part 60, Subpart J (NSPS Subpart J) for a Beavon Stretford Tail Gas Treatment unit.

The British Petroleum Whiting Business Unit (BP) is requesting a modification to the monitoring requirement option in 40 C.F.R. § 60.105(a)(7)(ii). BP proposes that rather than physically converting the total reduced sulfur (TRS) compounds and then measuring the sulfur dioxide ($SO_2$) with a continuous emission monitor (CEM) following Method 15A (40 C.F.R. § 60, Appendix A), it would like to mathematically calculate the expected $SO_2$ concentration using the existing TRS measurements and equation 15-2 in Method 15.

This monitoring method is consistent with the provisions of NSPS, Subpart J. The $SO_2$ concentration calculated above must comply with the 250 parts per million limit established in 40 C.F.R. § 60.105(a)(7)(ii).

If you have any questions regarding this letter, please contact Kushal Som, of my staff, at (312) 353-5792.

Sincerely,

George T. Czerniak, Chief
Air Enforcement and Compliance Assurance Branch

cc: Julie Armitage, Acting Manager
Bureau of Air—Compliance and Enforcement Section
Illinois Environmental Protection Agency

Don Sutton, Manager
Bureau of Air—Permits Section
Illinois Environmental Protection Agency

bp

Whiting Business Unit
BP Products North America Inc.
2815 Indianapolis Blvd.
PO Box 710
Whiting, IN 46394

***CERTIFIED MAIL***
***RETURN RECEIPT REQUESTED***

July 21, 2006

Bharat Mathur
Acting Regional Administrator
U.S. Environmental Protection Agency Region V
R-19J
77 West Jackson Boulevard
Chicago, IL 60604-3507

Re: **Request for Applicability Determination – BP Whiting Refinery**
**NSPS Subpart J – Sulfur Recovery Plants**

Dear Mr. Mathur:

The BP Whiting Refinery is requesting an applicability determination on the need for an alternative monitoring plan (AMP) pursuant to 40 CFR § 60.13(i) for NSPS Subpart J. If EPA determines that an AMP is warranted, this letter also serves as a request for approval of the AMP.

**Process Description**

The Whiting refinery operates three Sulfur Recovery Units (SRU); Claus Train A (rated at 150 ltd), B (rated at 150 ltd), and C (rated at 300 ltd), all of which are subject to those portions of 40 CFR Subpart J that are applicable to Claus sulfur recovery plants. Tail gas from the three Claus units is treated in a Beavon-Stretford tail gas treatment unit (TGTU).

The Beavon-Stretford TGTU is equipped with a combustor. However, this combustor is normally kept on hot standby (i.e. not operating at high temperatures), and the Whiting Refinery monitors compliance with the NSPS standards upstream of this combustor. As a result, the applicable NSPS standard is set out in 40 CFR § 60.104(a)(2)(ii), which applies to "reduction control systems not followed by incineration." That standard prohibits the discharge of gases containing more than "300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide ($H_2S$), each calculated as ppm $SO_2$ by volume (dry basis) at zero percent excess air."

While the foregoing standard appears to regulate both reduced sulfur compounds and $H_2S$ emissions, the rule does not specify an averaging time for the $H_2S$, nor does it require that $H_2S$ concentrations be monitored. Both of these facts resulted from conscious decisions by USEPA not to require monitoring for $H_2S$.

**Regulatory History**

The SRU emission standard was initially adopted on March 15, 1978 (43 FR 10866). This standard included both the 300 ppm reduced sulfur limit and the 10 ppm $H_2S$ limit and expressed both limits as rolling 12-hour averages:

> *40 CFR § 60.105(e)(3)(ii) (final) – Any twelve-hour period during which the average concentration of $SO_2$ in the gases discharged into the atmosphere from any Claus sulfur recovery plant subject to § 60.104(a)(2) exceeds 250 ppm at zero percent oxygen on a dry basis if compliance with § 60.104(b) is achieved through the use of an oxidation control system or a reduction control system followed by incineration; or any twelve-hour period during which the average concentration of $H_2S$, or reduced sulfur compounds in the gases discharged into the atmosphere of any Claus sulfur plant subject to § 60.104(a)(2)(b) exceeds 10 ppm or 300 ppm, respectively, at zero percent oxygen and on a dry basis if compliance is achieved through the use of a reduction control system not followed by incineration.*

However, as originally adopted, the standards contained no continuous monitoring requirements for either pollutant.

Amendments to NSPS Subpart J were promulgated on October 2, 1990 at 55 FR 40171. In these amendments, EPA adopted continuous monitoring requirements for reduced sulfur compounds but eliminated any mention of an averaging time for the $H_2S$ limit and explicitly declined to adopt any monitoring requirements for $H_2S$:

> *Hydrogen sulfide and reduced sulfur emitted from Claus plants are regulated by standards set at 10 and 300 ppm, respectively. Reduced sulfur compounds, though determined separately from $H_2S$, are also inclusive of $H_2S$ by definition. The Agency has determined that it is difficult to monitor the disproportionate concentrations of $H_2S$ and other reduced sulfur compounds on a continual basis, especially at levels near the standards. Therefore, <u>a separate determination of $H_2S$ apart from other reduced sulfur compounds will not be required, but only the continuous monitoring of reduced sulfur compounds. Performance Specification 5 and Method 15 or 15A will be used to evaluate the reduced sulfur CEMS performance.</u>*

The final rule also provided two options for monitoring compliance with requirements of 40 CFR § 60.104(a)(2)(ii):

- Pursuant to 40 CFR § 60.105(a)(6), an instrument for continuously monitoring and recording the concentration of reduced sulfur and $O_2$ emissions into the atmosphere.
- Pursuant to 40 CFR § 60.105(a)(7), an instrument using an air or $O_2$ dilution and oxidation system to convert the reduced sulfur to $SO_2$ for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant $SO_2$.

The monitor shall include an oxygen monitor for correcting the data for excess oxygen. For reporting purposes, the $SO_2$ exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

**BP's Current Practices and Request For Determination**

BP currently monitors total reduced sulfur compounds immediately downstream of the Beavon Stretford. However, the monitoring system also provides data on the $H_2S$ concentration in the treated tail gas. The concentration of reduced sulfur compounds (calculated as $SO_2$) is consistently well below 300 ppm, but, the concentration of $H_2S$ (calculated as $SO_2$) can, at times, rise above 10 ppm. When this occurs, the combustor, which is downstream of the monitoring point, is ramped up to assure that the excess $H_2S$ is destroyed before being emitted to the atmosphere.

BP has not historically reported such periods as "excess emissions" of $H_2S$ because (a) the concentration of $H_2S$ measured by the monitoring system is not representative of the concentration of $H_2S$ emitted to the atmosphere and (b) the standard includes neither an averaging time nor a monitoring requirement for $H_2S$. However, Whiting has recently discovered a 1993 NEIC inspection report that questioned this practice and suggested that BP "obtain approval from the Administrator, pursuant to 40 CFR 60.13(i), for the present method utilized by Amoco for monitoring compliance at the TGU."

BP believes that its current procedure is consistent with both the standards and monitoring requirements of Subpart J and requests EPA's concurrence in those practices.

In the alternative, however, BP requests approval of an alternative monitoring protocol under which the Beavon-Stretford TGTU would be deemed to be in compliance with the Subpart J requirements so long as the concentration of all reduced sulfur compounds as measured at the outlet of the Beavon Stretford (calculated as $SO_2$) is less than 250 ppm on a rolling 12-hour average.

This proposed alternative monitoring method is identical in principle to the alternative monitoring method already authorized by 40 CFR § 105(a)(7). As noted earlier, that section authorizes sources to monitor compliance with the reduced sulfur/$H_2S$ standard by using a monitoring system that physically oxidizes all reduced sulfur compounds (including $H_2S$) and then measures the $SO_2$. For reasons that are not entirely clear, however, the rule also provides that "For reporting purposes, the $SO_2$ exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air)." 40 CFR 60.105(a)(7)(ii).

Rather than physically converting the reduced sulfur compounds and then measuring the $SO_2$ with a CEMS following Method 15-A, Whiting proposes to mathematically calculate the expected $SO_2$ concentration using the existing TRS measurements and equation 15-2 in Method 15. For reporting purposes, this calculated $SO_2$ concentration would then be compared to a 250 ppm exceedance level as required by 40 CFR 60.105(a)(7)(ii).

BP Whiting Refinery
NSPS Subpart J Applicability Determination
July 21, 2006

We appreciate your attention to this issue. If you have any questions or comments about the enclosed information, please contact me at (219) 473-3287.

Sincerely,

Linda Wilson

Linda Wilson
Environmental Superintendent
Whiting Business Unit

cc: Cheryl Newton, USEPA Region V, A-18J
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# APPENDIX D
# EMISSION REDUCTIONS FROM FLARES AND CONTROL OF FLARING EVENTS

## FACTUAL BACKGROUND

BPP already has installed or has agreed to install through this Consent Decree a Gas Chromatograph ("GC"), and not a vent gas net heating value analyzer, on each Steam-Assisted Flare covered by this Consent Decree ("Covered Flares").

BPP will utilize the measured values from each GC together with other measured and/or calculated Net Heating Values to calculate the Net Heating Value of the Vent Gas directed to each Covered Flare.

The response time of a GC requires the use of an averaging time that is greater than the averaging time needed for a flare that utilizes a Vent Gas Net Heating Value Analyzers/Calculator.

Prior to completion of WRMP, Acid Gas will be routed to the SRU Flare, and after completion of WRMP, Acid Gas will be routed to the South Flare or to an alternative flare when the South Flare is out of service.

BPP does not have staged flares at the Whiting Refinery.

## DEFINITIONS

"Acid Gas" shall mean any gas that contains hydrogen sulfide and is generated at a refinery by the regeneration of an amine scrubber solution, but does not include Tail Gas.

"Acid Gas Flaring" or "AG Flaring" shall mean the combustion of Acid Gas and/or Sour Water Stripper Gas in one or more AG Flaring Device(s).

"Acid Gas Flare" or "AG Flare" shall mean a Flare that is used for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. BPP currently operates a Flare it has designated as the "SRU Flare" as an AG Flare at the Refinery. To the extent that, during the duration of this Consent Decree, BPP commences operation of an AG Flare other than or in addition to the SRU Flare for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, that or those AG Flare(s) shall be covered under Sections H and I of this Appendix.

"Acid Gas Flaring Incident" or "AG Flaring Incident" shall mean the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas in an AG Flare that results in the emission of $SO_2$ equal to, or in excess of, 500 pounds in any 24-hour period; provided, however, that if 500 pounds or more of sulfur dioxide has been emitted in a 24-hour period and Acid Gas Flaring continues into subsequent, contiguous, non-overlapping 24-hour period(s), each period of which results in emissions equal to, or in excess of, 500 pounds of $SO_2$, then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of flaring within the AG Flaring Incident. If, at any time during the term of this Consent Decree, the Whiting Refinery has more than one AG Flare, and if AG Flaring occurs within a 24 hour period at more than one such AG Flare, the quantity of sulfur dioxide attributable to AG Flaring emitted from each such AG Flare shall be added together for purposes of determining whether there is one AG Flaring Incident, unless the root causes of the flaring at the various AG Flares are not related to each other.

"Air-Assisted Flare" shall mean a Flare that utilizes forced air piped to a Flare tip to assist in combustion; a Flare that utilizes a Minimum Steam Reduction System is a Steam-Assisted, not an Air-Assisted, Flare.

"Air Mass Flow Rate at Stoichiometric Conditions based on Vent Gas Mass Flow Rate" or "$\dot{m}_{air\text{-}stoich\text{-}vg}$" shall mean the mass of air needed to reach a stoichiometric ratio based on the actual Vent Gas Mass Flow Rate. The $\dot{m}_{air\text{-}stoich\text{-}vg}$ is represented by and shall be calculated according to Equation 4 in Appendix FLR-15 of this Consent Decree.

"Assist Air" or "$Air_{asst}$" shall mean all air that intentionally is introduced into an Air-Assisted Flare to assist in combustion. Assist Air does not include ambient air, air introduced through in a Minimum Steam Reduction System, or air entrained in Vent Gas.

"Assist Air Mass Flow Rate" or "$\dot{m}_{air\text{-}asst}$" shall mean the mass flow rate of all Assist Air supplied to an Air-Assisted Flare, in pounds per hour (lb/hr), on a 5-minute block average basis. The $\dot{m}_{air\text{-}asst}$" is represented by and shall be calculated according to Equation 5 in Appendix FLR-15 of this Consent Decree.

"Automatic Control System" shall mean a system that utilizes programming logic to automate the operation of the instrumentation and systems required in Paragraphs 7 – 13, 42.a and 42.b of this Decree so as to produce the operational results required in Paragraphs 30, 33 – 35, 37, and 45.

"Baseload Waste Gas Flow Rate" shall mean, for a particular Covered Flare, the daily average flow rate, in scfd, to the Flare, excluding all flows during periods of startup, shutdown, and Malfunction. The flow rate data period that shall be used to determine Baseload Waste Gas Flow Rate for the Covered Flares is set forth in Subparagraph 18.b.ii. The Baseload Waste Gas Flow Rate shall be identified in the Initial Waste Gas Minimization Plan due under Subparagraph 18.b.ii and may be updated in subsequent Waste Gas Minimization Plans due under Paragraphs 19 and 20.

"BTU/scf" shall mean British Thermal Unit per standard cubic feet.

"Calendar Quarter" shall mean a three-month period ending on March 31, June 30, September 30, or December 31.

"Center Steam" or "$S_{cen}$" shall mean steam piped into the center of a Flare stack or center of the lower part of the Flare tip where it mixes directly with Vent Gas without entraining air.

Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix FLR-1 to this Consent Decree.

“Center Steam Volumetric Flow Rate” or “$Q_{s\text{-}cen}$” shall mean the volumetric flow rate of Center Steam supplied to a Flare, in scfm, as either measured (if applicable) or estimated using best engineering judgment, on a 5-minute block average.

“Center Steam Mass Flow Rate” or “$\dot{m}_{s\text{-}cen}$”” shall mean the mass flow rate of Center Steam supplied to a Flare, in pounds per hour, as either measured (if applicable) or estimated using best engineering judgment, on a 5-minute block average using Equation 2 in Appendix FLR-2.

“Cold Startup of the Refinery” shall mean the setting into operation of the entire Refinery after the entire Refinery has been shut down.

“Combustion Efficiency” or “*CE*” shall mean a Flare’s efficiency in converting the organic carbon compounds found in Vent Gas to carbon dioxide. Combustion Efficiency shall be determined as set forth in Equation 1 in Appendix FLR-2.

“Combustion Efficiency Multipliers” or “*CE* Multipliers” shall mean empirically-derived factors that are used as multipliers of the Net Heating Value of the Vent Gas at its Lower Flammability Limit to ensure an acceptable Combustion Efficiency. The *CE* Multipliers are set forth in Table 2 of Appendix FLR-3 of this Consent Decree.

“Combustion Zone” shall mean the area of the Flare flame where the combustion of Combustion Zone Gas occurs.

“Combustion Zone Gas” shall mean the mixture of all gases and steam found just after a Flare tip. This gas includes all Vent Gas, all Pilot Gas, all Total Steam (if the Flare is Steam-Assisted), and all Assist Air (if the Flare is Air-Assisted).

“Consent Decree” shall mean this Consent Decree, including any and all appendices attached hereto.

“Covered Flare” shall mean each of the following Elevated, Steam-Assisted Flares at the Refinery:

| Name | ID Number |
|---|---|
| VRU | 241-01 |
| FCU | 230-02 |
| Alky | 140-01 |
| 4UF | 224-06 |
| UIU | 220-04 |
| South | 800-04 |
| GOHT | 802-03 |

DDU 698-02

"Discontinuous Wake Dominated Flow" shall mean gas flow exiting a Flare tip that is identified visually by:

i. the presence of a flame that is: *(1)* immediately adjacent to the exterior of the Flare tip body; and *(2)* below the exit plane of the Flare tip; and

ii. pockets of flame that are detached from the portion of the flame that is immediately adjacent to the exterior of the Flare tip body.

Representations of Discontinuous Wake Dominated Flow are set forth in Appendix FLR-13.

"Elevated Flare" shall mean a Flare that supports combustion at a tip that is situated at the upper end of a vertical conveyance (*e.g.*, pipe, duct); the combustion zone is elevated in order to separate the heat generated by combustion from people, equipment, or structures at grade level.

"Exit Velocity" shall mean the velocity ("*v*") of the Vent Gas and Center Steam as it exits the flare tip. Exit Velocity shall be calculated by adding together the Vent Gas Volumetric Flow Rate and the Center Steam Volumetric Flow Rate and dividing by the Unobstructed Cross Sectional Area of the Flare Tip.

"External Power Loss" shall mean a loss in the supply of electrical power to the Refinery that is caused by events occurring outside the boundaries of the Refinery, excluding power losses due to an interruptible power service agreement.

"First Updated Waste Gas Minimization Plan" or "First Updated WGMP" shall mean the document submitted pursuant to Paragraph 19 as the first update to the Initial WGMP.

"Flare" shall mean a combustion device that uses an uncontrolled volume of ambient air to burn gases.

"Flare Gas Recovery System" or "FGRS" shall mean a system of one or more compressors, piping, and associated water seal, rupture disk, or similar device used to divert gas from a Flare and direct the gas to a fuel gas system, to a combustion device other than the Flare, or to a product, co-product, by product, or raw material recovery system.

"Hydrocarbon Flaring" or "HC Flaring" shall mean the combustion of refinery-generated gases, except for Acid Gas, Sour Water Stripper Gas, and/or Tail Gas, in a Hydrocarbon Flare.

"Hydrocarbon Flare" or "HC Flare" shall mean a Flare used to combust any refinery-generated gas other than Acid Gas and/or Sour Water Stripper Gas and/or Tail Gas. The Hydrocarbon Flares that BPP operates at the Refinery include each of the Covered Flares and the LPG Flare. To the extent that, during the duration of the Consent Decree, BPP commences operation of any HC Flaring Devices other than or in addition to those specified herein for the purposes of combusting any excess of a refinery-generated gas other than Acid Gas and/or Sour Water Stripper Gas and/or Tail Gas, then any such flares that are: (i) Steam-Assisted shall be covered by Sections A-F, H, and J-K of this Appendix; or (ii) Air-Assisted shall be covered by Sections E, G-H, and J-K of this Appendix. Compliance with the applicable requirements shall commence on the first date of that any such new flare receives Waste Gas from the Refinery.

"Hydrocarbon Flaring Incident" or "HC Flaring Incident" shall mean either of the following:

i. "HC Flaring Incident – Trigger 1": the continuous or intermittent combustion of refinery-generated gases, except for Acid Gas, Sour Water Stripper Gas, or Tail Gas, at a Hydrocarbon Flare that results in the emission of sulfur dioxide equal to or greater than five-hundred (500) pounds in any 24-hour period; provided, however, that if 500 pounds or more of sulfur dioxide has been emitted in any 24-hour period and flaring continues into subsequent, contiguous, non-overlapping 24-hour period(s), each period of which results in emissions equal to, or in excess of, 500 pounds of sulfur dioxide, then only one HC Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the HC Flaring Incident. When HC Flaring occurs within a 24-hour period at more than one HC Flare, the quantity of sulfur dioxide attributable to HC Flaring emitted from each HC Flare shall be added together for purposes of determining whether there is one HC Flaring Incident, unless the root causes of the flaring at the various HC Flaring Devices are not related to each other; or

ii. "HC Flaring Incident – Trigger 2": the combustion of 500,000 standard cubic feet or more of Waste Gas (excluding Acid Gas, Sour Water Stripper Gas, and Tail Gas) within a 24-hour period at a Hydrocarbon Flare. For purposes of calculating Waste Gas flow rate, the following flows may be excluded: (i) the pro-rated Baseload Waste Gas Flow Rate (pro-rated on the basis of the duration of the Flaring Incident); and (ii) if BPP has instrumentation capable of measuring the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or steam in the Waste Gas, the contribution of all measured flows of any of these elements/compounds. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the HC Flaring Incident. When HC Flaring occurs within a 24-hour period at more than one HC Flare, the volume of Waste Gas attributable to HC Flaring emitted from each HC Flare shall be added together for purposes of determining whether there is one HC Flaring Incident, unless the root causes of the flaring at the various HC Flaring Devices are not related to each other.

"Initial Waste Gas Minimization Plan" or "Initial WGMP" shall mean the document submitted pursuant to Paragraph 18.

"Lower Flammability Limit" or "*LFL*" shall mean the lowest volumetric concentration of a combustible gas in air that, at a given temperature and pressure, will still combust.

"Lower Flammability Limit Table" shall mean Table 1 of Appendix FLR-3. Table 1 lists, *inter alia*, the LFLs of individual compounds found in Vent Gas.

"Lower Flammability Limit of Vent Gas" or "$LFL_{vg}$" shall mean the weighted average of the LFLs of each of the individual compounds in Vent Gas, weighted by their volume percent in the Vent Gas. $LFL_{vg}$ is represented by and shall be calculated according to Equation 1 in Appendix FLR-3 of this Consent Decree.

"Lower Heating Value" or "*LHV*" shall mean the theoretical total quantity of heat liberated by the complete combustion of a unit volume or weight of a fuel initially at $25^{\circ}$ Centigrade and 760 mmHg, assuming that the produced water is vaporized and all combustion products remain at, or are returned to, $25^{\circ}$ Centigrade; however, the standard for determining the volume corresponding to one mole is $20^{\circ}$ Centigrade.

"Lower Steam" shall mean steam piped to an exterior annular ring near the lower part of a Flare tip, which entrains Air which flows through tubes to the Flare tip, and ultimately exits the tubes at the Flare tip. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix FLR-1 to this Consent Decree.

"LPG Flare" shall mean the Elevated, Air-Assisted Flare at the Refinery that BPP designates by ID No. 604-01**.**

"Malfunction" shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions. In any action under this Consent Decree involving this definition, BPP shall have the burden of proving a Malfunction and, in interpreting this definition, the ten requirements for a "malfunction" set forth in Section II ("*Affirmative Defenses for Malfunctions"*) of EPA's Policy on Excess Emissions during Malfunctions, Startup, and Shutdown shall apply. This Policy is attached as Appendix FLR-4.

"Minimum Steam Rate" or "Minimum Steam" shall mean the Total Steam Mass Flow Rate, in standard cubic feet per minute or in pounds per hour, recommended by the manufacturer of the Flare's tip at the time of flare tip installation, or such lower Total Steam Mass Flow Rate as determined by the Flare tip manufacturer after Flare tip installation upon re-examination of the tip's requirements.

"Minimum Steam Reduction System" or "MSRS" shall mean a system that utilizes a mixed stream of air and steam to reduce the minimum steam requirements of a Steam-Assisted Flare.

"Momentum Flux Ratio" or "*MFR*" shall mean the ratio of the Vent Gas and Center Steam momentum flux to the wind momentum flux, where momentum flux is the momentum per unit area, per unit time. *MFR* characterizes the degree to which the ambient air affects the trajectory of the Vent Gas and Center Steam just as it exits the Flare tip. *MFR* is represented by Equation 1 in Appendix FLR-5 and shall be calculated in accordance with the equations, conversion factors, *MFR* constants, *MFR* measured variables, and *MFR* calculated variables set forth in Appendix FLR-5.

"Net Heating Value" shall mean Lower Heating Value.

"Net Heating Value of Combustion Zone Gas" or "$NHV_{cz}$" shall mean the Lower Heating Value, in BTU/scf, of the Combustion Zone Gas in a Flare. $NHV_{cz}$ is represented by Equation 5 in Appendix FLR-3 to this Consent Decree and shall be calculated in accordance with Equations 5 - 8 of Appendix FLR-3. To the extent a Covered Flare ever is equipped with a Minimum Steam Reduction System, BPP also shall use Equations 9 – 13 to calculate $NHV_{cz}$.

"Net Heating Value of the Combustion Zone Gas Limit" or "$NHV_{cz\text{-}limit}$" shall mean the minimum Net Heating Value that the Combustion Zone Gas must have to ensure an acceptable Combustion Efficiency. $NHV_{cz\text{-}limit}$ shall be calculated no less than one time every 15 minutes through the use of Equation 4 in Appendix FLR-3 of this Consent Decree.

"Net Heating Value of Hydrogen as Adjusted" or "$\text{NHV}_{H2\text{-}adj}$" shall mean 1212 BTU/scf. $\text{NHV}_{H2\text{-}adj}$ represents an adjustment to hydrogen's actual Net Heating Value for use, consistent with Step 3 of Appendix 1.3, in the calculation of the Net Heating Value of Vent Gas.

"Net Heating Value of Vent Gas" or "$NHV_{vg}$" shall mean the Lower Heating Value, in BTU/scf, of the Vent Gas directed to a Flare. $NHV_{vg}$ is calculated as set forth in Equation 2 in Appendix FLR-3.

"Net Heating Value of Vent Gas at its Lower Flammability Limit" or "$NHV_{vg\text{-}LFL}$" shall mean the Lower Heating Value, in BTU/scf, of the Vent Gas at its LFL. $NHV_{vg\text{-}LFL}$ is represented by and shall be calculated in accordance with Equation 3 of Appendix FLR-3 of this Consent Decree.

"Passive FTIR" shall mean a Fourier Transform Infrared System that collects thermal (infrared) radiation emitted by a hot gas plume, and through the analysis of the resulting emission spectrum, identifies and quantifies the compounds producing values proportional to the path-integrated gas concentrations.

"Pilot Gas" shall mean all gas introduced through the pilot tip of a Flare to maintain a flame.

"Prevention Measure" shall mean an instrument, device, piece of equipment, system, process change, physical change to process equipment, procedure, or program to minimize or eliminate flaring.

"Purge Gas" shall mean the minimum amount of gas introduced between a Flare header's water seal and the Flare tip to prevent oxygen infiltration (backflow) into the Flare tip. For a Flare with no water seal, the function of Purge Gas is performed by Sweep Gas, and therefore, by definition, such a Flare has no Purge Gas.

"Refinery" shall mean the refinery that BPP owns and operates at 2815 Indianapolis Blvd, Whiting, Indiana.

"Reportable Flaring Incident" shall mean each of the following: Acid Gas Flaring Incident; Tail Gas Incident; and Hydrocarbon Flaring Incident.

"Root Cause Analysis" shall mean the primary and any contributing causes of a Reportable Flaring Incident as determined through a process of investigation.

"SCFD" or "scfd" shall mean standard cubic feet per day.

"SCFM" or "scfm" shall mean standard cubic feet per minute.

"Shutdown" shall mean the cessation of operation for any purpose.

"Sour Water Stripper Gas" or "SWS Gas" shall mean the gas produced by the process of stripping refinery sour water.

"Smoke Emissions" shall have the definition set forth in Section 3.5 of Method 22 of 40 C.F.R. Part 60, Appendix A. Smoke Emissions may be documented by either a person certified pursuant to Method 22 or by a video camera.

"SRU Flare" shall mean the Elevated Flare associated with the sulfur recovery unit at the Refinery that BPP designates with ID No. 162-03.

"Standard Conditions" shall mean a temperature of 68 degrees Fahrenheit and a pressure of 1 atmosphere. Unless otherwise expressly set forth in this Consent Decree or an Appendix, Standard Conditions shall apply.

"Startup" shall mean the setting in operation for any purpose.

"Steam-Assisted Flare" shall mean a Flare that utilizes steam piped to a Flare tip to assist in combustion. A Flare that utilizes a Minimum Steam Reduction System is a Steam-Assisted, not an Air-Assisted, Flare.

"Supplemental Gas" shall mean all gas introduced to a Flare to comply with the net heating value requirements of 40 C.F.R. § 60.18(b), 40 C.F.R. § 63.11(b), and/or Paragraph 33 of this Appendix.

"*S/VG*" or "Total-Steam-Mass-Flow-Rate-to-Vent-Gas-Mass-Flow-Rate Ratio" shall mean the ratio of the Total Steam Mass Flow Rate to the Vent Gas Mass Flow Rate.

"Sweep Gas" shall mean:

i. For a Flare with a Flare Gas Recovery System: the minimum amount of gas introduced into a Flare header in order to: *(a)* prevent oxygen buildup, corrosion, and/or freezing in the Flare header; and *(b)* maintain a safe flow of gas through the Flare header. Sweep Gas in these Flares is introduced prior to and is intended to be recovered by the Flare Gas Recovery System;

ii. For a Flare without a Flare Gas Recovery System: the minimum amount of gas introduced into a Flare header in order to: *(a)* prevent oxygen buildup, corrosion, and/or freezing in the Flare header; *(b)* maintain a safe flow of gas through the Flare heater; and *(c)* prevent oxygen infiltration (backflow) into the Flare tip.

"Tail Gas" shall mean the exhaust gas from the Claus train(s) of a sulfur recovery plant and/or from the Tail Gas Unit.

"Tail Gas Incident" shall mean either of the following:

i. "Tail Gas Incident – Trigger 1": Tail Gas that is combusted in a flare and results in excess emissions of 500 pounds or more of $SO_2$ in any 24-hour period; or

ii. "Tail Gas Incident – Trigger 2": Tail Gas that is combusted in a thermal incinerator and results in excess emissions of 500 pounds or more of $SO_2$ emissions in any twenty-four (24) hour period. Only emissions which are in excess of a $SO_2$ concentration of 250 ppm (rolling twelve-hour average) shall be used to determine the amount of excess $SO_2$ emissions from the incinerator.

Tail Gas Incidents may include, but are not limited to, any of the following: a TGU shutdown, a TGU bypass, and a scheduled or unscheduled shutdown of a sulfur recovery plant. For Tail Gas Incidents – Trigger 2, BPP shall use good engineering judgment and/or other monitoring data to calculate emissions during periods in which the $SO_2$ continuous emission analyzer has exceeded the range of the instrument or the instrument is out of service.

"Tail Gas Unit" or "TGU" shall mean a control system utilizing a technology for reducing emissions of sulfur compounds from a sulfur recovery plant.

"Temporary-Use Flare" shall mean a flare that receives Waste Gas that has been redirected to it from another flare for 504 hours or less on a rolling 1095 day average period.

"Total Steam" or "*S*" shall mean the total of all steam that intentionally is introduced into a Steam-Assisted Flare to assist in combustion. Total Steam includes, but is not limited to, Lower Steam, Center Steam, and Upper Steam.

"Total Steam Volumetric Flow Rate" or "$Q_s$" shall mean the volumetric flow rate of Total Steam supplied to a Flare, in scfm as measured on a 5-minute block average.

"Total Steam Mass Flow Rate" or "$\dot{m}_s$" shall mean the mass flow rate of Total Steam supplied to a Flare, in pounds per hour as calculated on a 5-minute block average. Total Steam Mass Flow Rate shall be calculated as set forth in Equation 3 in Appendix FLR-2.

"Unobstructed Cross Sectional Area of the Flare Tip" or "$A_{tip\text{-}unob}$" shall mean the open, unobstructed area of a Flare tip through which Vent Gas and Center Steam pass. Diagrams of four common flare types are set forth in Appendix FLR-6 together with the equations for calculating the $A_{tip\text{-}unob}$ of these four types.

"Upper Steam," sometimes called Ring Steam, shall mean steam piped to nozzles located on the exterior perimeter of the upper end of a Flare tip. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix FLR-1 to this Consent Decree.

"Variable Speed Motor" shall mean a motor that operates at continuously variable speeds between a minimum and maximum as regulated by a Variable Speed Drive.

"Variable Speed Drive" shall mean a piece of equipment that regulates the speed and rotational force, or torque output, of an electric motor and that outputs a variable frequency to a motor to allow it to operate at variable speeds between the motor's minimum and maximum speed.

"Velocity of the Wind" or "$v_{\text{wind}}$" shall mean the velocity of the ambient air, in ft/s on a one-minute block average, measured at the Meteorologic Station required pursuant to Paragraph 12 of this Appendix.

"Vent Gas" shall mean the mixture of all gases found prior to the Flare tip. This gas includes all Waste Gas, Sweep Gas, Purge Gas, and Supplemental Gas, but does not include Pilot Gas, Total Steam, or Assist Air.

"Vent Gas Volumetric Flow Rate" or "$Q_{vg}$" shall mean the volumetric flow rate of Vent Gas directed to a Covered Flare, in wet scfm, on a 5-minute block average basis.

"Vent Gas Mass Flow Rate" or "$\dot{m}_{vg}$" shall mean the mass flow rate of Vent Gas directed to a Covered Flare, in pounds per hour on a 5-minute block average. Vent Gas Mass Flow Rate shall be calculated as set forth in Equation 4 in Appendix FLR-2.

"Vent Gas Molecular Weight" or "$MW_{vg}$" shall mean the Molecular Weight, in pounds per pound-mole, of the Vent Gas, on a 5-minute block average.

"Visible Emissions" shall mean five minutes or more during any two consecutive hours of Smoke Emissions. For purposes of this Appendix, Visible Emissions may be documented by either a person certified pursuant to Method 22 or by a video camera.

"VOC" or "Volatile Organic Compounds" shall have the definition set forth in 40 C.F.R. Section 51.100(s).

"VOC Vent Gas Concentration" shall mean the volumetric concentration of VOCs in the Vent Gas and shall be calculated as set forth in Equation 16 of Table 2 of Appendix FLR-3.

"Waste Gas" shall mean the mixture of all gases from facility operations that is directed to a flare for the purpose of disposing of the gas. "Waste Gas" does not include gas introduced to a flare exclusively to make it operate safely and as intended; therefore, "Waste Gas" does not include Pilot Gas, Total Steam, Assist Air, or the minimum amount of Sweep Gas and Purge Gas that is necessary to perform the functions of Sweep Gas and Purge Gas. "Waste Gas" also does not include gas introduced to a flare to comply with regulatory requirements; therefore, "Waste Gas" does not include Supplemental Gas. Depending upon the instrumentation that measures Waste Gas, certain compounds (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, and/or water (steam)) that are directed to a Flare for the purpose of disposing of these compounds may be excluded from calculations relating to Waste Gas flow; in the substantive provisions of this Appendix, the circumstances in which such exclusions are permitted are specifically identified. Appendix FLR-7 to this Consent Decree depicts the meaning of "Waste Gas," together with its relation to other gases associated with Flares.

**CONTROLS OF FLARES AND FLARING EVENTS**

**A. Interim Measures for Flare Combustion Efficiency and Vent and Waste Gas Minimization at the Covered Flares**

1. Interim Combustion Efficiency Measures.

a. By no later than 45 days after the Date of Entry, based on the monitoring systems and instrumentation existing at each Covered Flare as of the Date of Entry, BPP shall complete the installation of a system that depicts, on each Covered Flare's control panel, a visual image of the *S/VG* ratio of each Covered Flare.

b By no later than 90 days after the Date of Entry, for all operators and supervisors with responsibility and/or oversight for the operation of each Covered Flare, BPP shall complete training on steam control for each Covered Flare. Such training shall include describing and identifying the existing monitoring and instrumentation systems, how to manually adjust Total Steam Volumetric Flow Rate so as to optimize Combustion Efficiency and minimize oversteaming, and how to target the *S/VG* ratio at the lowest possible value to just avoid Smoke Emissions.

c. By no later than 90 days after the Date of Entry, based on the visual readout at the control panel for each Covered Flare, BPP shall operate each Covered Flare to minimize the *S/VG* ratio to the extent practical with the existing monitoring and instrumentation systems.

2. Evaluating and Upgrading or Replacing, as Necessary, Meters Measuring Sweep Gas and Purge Gas Volumetric Flow Rates. By no later than one year after the Date of Entry, BPP shall complete an evaluation of all meters that measure the flow of Sweep Gas and Purge Gas to each Covered Flare and shall upgrade or replace, as necessary, each such meter in order to ensure an acceptable level of control over flow.

3. Minimizing Sweep and Purge Gas Flow Rates based on Survey Findings. Prior to one year after the Date of Entry, BPP shall complete a survey of the amount of Sweep Gas and Purge Gas introduced to each Covered Flare. Based on the results of the survey, by no later than one year after the Date of Entry, BPP shall complete the implementation of all measures necessary to minimize the amount of Sweep Gas and Purge Gas being directed to each Covered Flare. If the implementation of any such measure takes longer than one year after the Date of Entry, BPP shall complete the implementation as soon as practicable and shall provide a schedule for such completion in the first semi-annual report under Section VIII of this Decree that is due after one year after the Date of Entry. Under no circumstances may BPP implement any such measure later than the turnaround for the affected unit that first occurs after one year after the Date of Entry.

4. Minimizing Leaking Pressure Relief Valves ("PRVs"). By no later than one year after the Date of Entry, BPP shall conduct and complete a survey ("Initial PRV Leak Survey") of the large, high-pressure hydrocarbon pressure relief valves ("PRVs") at the Refinery identified in Appendix FLR-8. The Initial PRV Leak Survey will include but not be limited to acoustic monitoring. During the first Maintenance Shutdown that occurs after eighteen months following completion of the Initial PRV Leak Survey of any unit that houses any PRV listed in Appendix FLR-8, BPP shall repair or replace each leaking PRV in that unit. For all other hydrocarbon PRVs at the Refinery (that is, all those that are not identified in Appendix FLR-8) that are tied into Flare headers and subheaders, BPP shall conduct acoustic monitoring pursuant to a plan and schedule that BPP shall include in the Initial Waste Gas Minimization Plan due under Paragraph 18.

## B. Instrumentation and Monitoring Systems for Covered Flares

5. Flare Data and Monitoring Systems and Protocol Report ("Flare Data and Monitoring Systems and Protocol Report"). By no later than June 30, 2013, for all Covered Flares, BPP shall submit a report to EPA that includes the following:

a. The information, diagrams, and drawings specified in Parts 1 – 8 of Appendix FLR-9;

b. A detailed description of each instrument and piece of monitoring equipment, including the specific model and manufacturer, that BPP has installed or will install in compliance with Paragraphs 7 – 13 (Part 9 of Appendix FLR-9); and

c. A narrative description of the monitoring methods and calculations that BPP shall use to comply with the requirements of Paragraphs 33 – 35 (Part 10 of Appendix FLR-9).

d. The identification of the calibration gases to be used to comply with Subparagraph V.B.1 of Appendix FLR-11 (Part 11 of Appendix FLR-9).

For any $H_2S$ CEMS required pursuant to 40 C.F.R. Part 60, Subpart J or Subpart Ja, this report shall satisfy the notification requirements of 40 C.F.R. § 60.7(a)(5).

6. <u>Installation and Operation of Monitoring Systems</u>.

a. By no later than startup of the South Flare, and December 31, 2013 for all other Covered Flares, BPP shall have completed the installation and commenced the operation of the instrumentation, controls, and monitoring systems set forth in Paragraphs 7 - 13.

b. BPP may elect to re-position or upgrade the existing Panametric flow meters on the DDU, VRU, FCU, Alky, 4UF and UIU Flares in order to meet the accuracy requirement in Appendix FLR-11. BPP shall complete any such upgrades or re-positioning by December 31$^{st}$ of the following years:

| <u>Covered Flare</u> | <u>Re-position or Upgrade Panametric Flow Meter</u> |
|---|---|
| DDU | 2014 |
| FCU | 2014 |
| VRU | 2015 |
| Alky | 2016 |
| 4UF | 2016 |
| UIU | 2017 |

7. <u>Vent Gas Flow Monitoring System</u>. By means of this system, BPP shall determine the Vent Gas Volumetric and Mass Flow Rates at each Covered Flare. This system shall:

a. Continuously measure the total flow, in scfm or pounds per hour, of the gas flowing through it;

b. Continuously analyze pressure and temperature at each point of flow measurement;

c. Have dual channel measurement at each point of flow measurement for flow meters using an ultrasonic flow measurement method; and

d. Have retractable or removable sensors at each point of flow measurement to ensure that the flow meter is maintainable online.

Prior to any necessary relocation of the Panametrics flow meter pursuant to Paragraph 6, the Vent Gas Flow Monitoring System shall consist of (1) an ultrasonic flow meter that is measuring the flow of gas in the header prior to the flare stack (after all addition of Waste Gas from process units) or in the flare stack; (2) a flow meter measuring any Supplemental Gas that may be supplied to the flare stack and that is not already measured by the ultrasonic flow meter; and (3) a flow meter measuring any Purge Gas that may be supplied to the flare stack and that is not already measured by the ultrasonic flow meter. After the relocation of the ultrasonic flow meter pursuant to Paragraph 6, the Vent Gas Flow Monitoring System shall consist of (1) an ultrasonic flow meter that is measuring the flow of gas in the header prior to the water seal and after any FGRS; (2) a flow meter measuring any Supplemental Gas that may be supplied to the flare stack and that is not already measured by the ultrasonic flow meter; and (3) a flow meter measuring any Purge Gas that may be supplied to the flare stack and that is not already measured by the ultrasonic flow meter. In all cases, the system, in its complete configuration, shall accurately measure Volumetric Vent Gas Flow Rate as defined by this Consent Decree.

8. Vent Gas Average Molecular Weight Analyzer. By means of this system, BPP shall determine the average Molecular Weight of the Vent Gas at each Covered Flare. BPP shall utilize the molecular weight analyzer in the ultrasonic flow meter at each Covered Flare to determine the molecular weight of the gas flowing to each such flow meter. BPP shall assume a constant molecular weight for the Purge Gas and Supplemental Gas that is representative of the molecular weight of natural gas supplied from the local gas company (NIPSCO) at each Covered Flare.

9. Total Steam Flow Monitoring System. This system shall:

a. Continuously measure the flow, in scfm and pounds per hour, of the Total Steam to the Covered Flare; and

b. Continuously analyze the pressure and temperature of steam at a representative point of steam flow measurement.

10. Steam Control Equipment. This equipment, including, as necessary, main and trim control valves and piping, shall enable BPP to control steam flow in a manner sufficient to ensure compliance with this Decree.

11. Gas Chromatograph ("GC"). This instrument shall be capable of speciating the gas constituents set forth in Appendix FLR-10. For all constituents except Hydrogen Sulfide ("$H_2S$"), the GC shall measure the concentration on a mole percent ("mol/mol%") basis; for $H_2S$, the GC shall measure the concentration on a parts per million volume basis ("ppmv").

12. Meteorologic Station or "Met Station" (for the Refinery, not each Covered Flare). This station shall include meteorologic data instruments capable of measuring wind speed. The station shall be located in the refinery at Gate 36.

13. Video Camera. This instrument shall record, in digital format, the flame of, and any Smoke Emissions and/or Wake Dominated Flow from, each Covered Flare.

14. Instrumentation and Monitoring Systems: Optional Equipment for any Covered Flare. At its option, BPP may elect to install (if not already installed) and continuously measure the flow, in scfm or pounds per hour (if the instrument automatically converts flow from scfm to lb/hr), of all Pilot Gas to a Covered Flare. BPP may utilize the data generated by this system as part of the calculation of the Net Heating Value of the Combustion Zone Gas.

15. Instrumentation and Monitoring Systems: Specifications. The instrumentation and monitoring systems identified in Paragraphs 7 – 9 and 11 - 12 shall meet or exceed the specifications set forth in Appendix FLR-11.

16. Instrumentation and Monitoring Systems: Recording and Averaging Times. The instrumentation and monitoring systems identified in Paragraphs 7 – 9 and 11 - 13 shall be able to produce and record data measurements and calculations for each parameter at the following time intervals:

| Instrumentation and Monitoring System | Recording and Averaging Times |
|---|---|
| Vent Gas Flow;<br>Vent Gas Average Molecular Weight;<br>Total Steam Flow;<br>Pilot Gas Flow (if installed) | Measure continuously and record 5 minute block averages |
| Gas Chromatograph | Measure no less than once every 15 minutes and record that value |
| Wind Speed | Measure continuously and record 5 minute block averages |
| Video Camera | Record at a rate of no less than 4 frames per minute |

17. Instrumentation and Monitoring Systems: Operation and Maintenance. BPP shall operate each of the instruments and monitoring systems required in Paragraphs 7 - 9, 11 - 13, and 42.a and 42.b on a continuous basis except for the following periods:

a. Malfunction of an instrument and/or monitoring system;

b. Maintenance following instrument Malfunction;

c. Scheduled maintenance of an instrument in accordance with the manufacturer's recommended schedule;

d. Quality Assurance/Quality Control activities; and/or

e. When the Covered Flare that the instrument or monitoring system is associated with is not in service.

Provided however, that in no event shall the excepted activities in Subparagraphs 17.a—17.c for any instrument exceed 110 hours in any calendar quarter. The calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VI of Appendix FLR-11. If the excepted activities in Subparagraphs 17.a—17.c exceed 110 hours in any calendar quarter, EPA shall be entitled to seek stipulated penalties under Paragraph 150.j of Part X ("Stipulated Penalties") and BPP shall be entitled to assert that the period of instrumentation and monitoring system downtime was justified under the circumstances. Nothing in this Paragraph is intended to prevent BPP from claiming a *force majeure* defense to any period of instrumentation and/or monitoring system downtime. Nothing in this Paragraph supersedes or replaces the monitoring requirements, including operation, maintenance, and quality assurance/quality control requirements, of 40 C.F.R. Part 60, Subparts J and Ja (including monitoring requirements in 40 C.F.R. Part 60, Subpart Ja that may be stayed as of the Date of Lodging of this Consent Decree but may become effective after the Date of Lodging) at such time as those requirements become applicable pursuant to Paragraphs 69 and 70. All such requirements shall apply in accordance with the terms set forth in 40 C.F.R. Part 60, Subparts J and Ja.

## C. Vent and Waste Gas Minimization for Covered Flares

18. Initial Waste Gas Minimization Plan ("Initial WGMP"). By no later than June 30, 2015, for all Covered Flares, BPP shall submit to EPA an Initial Waste Gas Minimization Plan for each Covered Flare that discusses and evaluates flaring Prevention Measures both Refinery-wide and on a Flare-specific basis. The Initial WGMP shall include but not be limited to:

a. Updates. BPP shall submit updates, if and as necessary, to the information, diagrams, and drawings provided in the Flare Data and Monitoring Systems and Protocol Report required under Paragraph 5.

b. Waste Gas Characterization and Mapping. BPP shall undertake to characterize the Waste Gas being disposed of at each Covered Flare and determine its source as follows:

i. Volumetric (in scfm) and mass (in pounds) flow rate. BPP shall identify the volumetric flow of Waste Gas, in scfm on a 30-day rolling average, and the mass flow rate, in pounds per hour on a 30-day rolling average, vented to each Covered Flare between January 1, 2014, and December 31, 2014. To the extent that, for any particular Covered Flare, BPP has instrumentation capable of measuring the volumetric and mass flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or steam in the Waste Gas, BPP may break down the volumetric and mass flow as between: (i) All Waste Gas flows excluding hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam); and (ii) hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) flows in the

Waste Gas. BPP may use either an engineering evaluation or measurements from monitoring or a combination to determine flow rate. In determining flow rate, flows during all periods (including but not limited to normal operations and periods of startup, shutdown, Malfunction, process upsets, relief valve leakages, power losses due to an interruptible power service agreement, and emergencies arising from events within the boundaries of the Refinery), except those described in the next sentence, shall be included. Flows that could not be prevented through reasonable planning and are caused by a natural disaster, act of war or terrorism, or External Power Loss are the only flows that shall be excluded from the calculation of flow rate. BPP shall specifically describe the date, time, and nature of the event that results in the exclusion of any flows from the calculation.

ii. Baseload Waste Gas Flow Rates. BPP shall utilize flow rate data to determine the Baseload Waste Gas Flow Rate, in scfd, to each Covered Flare, other than the South and GOHT Flares. The Baseload Waste Gas Flow Rate shall not include flows during periods of startup, shutdown, and Malfunction. The Baseload Waste Gas Flow Rate shall be based on the period between January 1, 2014, and December 31, 2014

iii. Identification of Constituent Gases. BPP shall use best efforts to identify the constituent gases within each Covered Flare's Waste Gas and the percentage contribution of each such constituent during baseload conditions. BPP may use either an engineering evaluation or measurements from monitoring or a combination to determine Waste Gas constituents.

iv. Waste Gas Mapping. Using instrumentation, isotopic tracing, and/or engineering calculations, BPP shall identify and estimate the flow from each process unit flare header to the main Flare header(s). Using that information and all other available information, BPP shall complete an identification of each Waste Gas tie-in to the main Flare header(s) and process unit flare header(s), as applicable, consistent with Appendix FLR-12. Temporary connections to a Flare's header(s) and/or subheader(s) are not required to be included in the mapping.

c. Reductions previously realized. BPP shall describe the equipment, processes and procedures installed or implemented within the last three years to reduce flaring. The description shall specify the date of installation or implementation and the amount of reductions realized.

d. Planned reductions. BPP shall describe the equipment, processes, or procedures that BPP plans to install or implement to eliminate or reduce flaring. The description shall specify a schedule for expeditious installation and commencement of operation and a projection of the amount of reductions to be realized. In formulating this plan, BPP specifically shall review and evaluate the results of the Waste Gas Mapping required by Subparagraph 18.b.iv.

e. Taking a Covered Flare out of Service. BPP shall identify any Covered Flare that it intends to take out of service, including the date for completion of the decommissioning. Taking a Covered Flare "out of service" means physically removing piping in the Flare header or physically isolating the piping with a welded blind so as to eliminate direct piping to the Covered Flare.

f. Prevention Measures. BPP shall describe and evaluate all Prevention Measures, including a schedule for the expeditious implementation and commencement of operation of all prevention measures, to address the following:

i. Flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including startup and shutdown. The evaluation shall include a review of flaring that has occurred during these activities in the past three years and shall consider the feasibility of performing these activities without flaring.

ii. Flaring that may reasonably be expected to occur due to issues of gas quantity and quality. The evaluation shall include an audit of the flare gas recovery capacity of each Covered Flare, the storage capacity available for excess Waste Gases, and the scrubbing capacity available for Waste Gases including any limitations associated with scrubbing Waste Gases for use as fuel. The evaluation shall consider the feasibility of reducing flaring through the recovery, treatment, and use of the Waste Gas.

iii. Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall consider the adequacy of existing maintenance schedules and protocols for such equipment. A failure is "recurrent" if it occurs more than twice during any five year period as a result of the same root cause.

19. First Updated Waste Gas Minimization Plan. By no later than June 30, 2016, for all Covered Flares, BPP shall submit to EPA a First Updated WGMP, which shall update for the preceding calendar year, if and as necessary, the information required in Subparagraphs 18.a – 18.f and shall also include the following:

a. Updated Waste Gas Mapping. BPP shall update the Waste Gas mapping as more information becomes available. BPP shall use this updated mapping to plan reductions;

b. Reductions based on Root Cause Analysis. BPP shall review all of the Root Cause Analysis reports prepared pursuant to Paragraph 54 to determine if reductions in addition to the reductions achieved through any corrective action under Paragraph 55 can be realized; and

c. Revised Schedule. To the extent that BPP proposes to extend any schedule set forth in the Initial WGMP, BPP shall do so only with good cause.

20. Subsequent Updates to Waste Gas Minimization Plan. In the first semi-annual report required under Part VIII that is due after June 30, 2017, BPP shall submit a Second Updated WGMP. On an annual basis thereafter until termination of the Decree, BPP shall

submit an updated WGMP as part of the applicable semi-annual report. Each update shall update, if and as necessary, the information required in Subparagraphs 18.a – 18.f, 19.a, and 19.b. To the extent that BPP proposes to extend any schedule set forth in a previous WGMP, BPP shall do so only with good cause.

21. a. Waste Gas Minimization Plan: Implementation. By no later than the dates specified in a WGMP, BPP shall implement the actions described therein. If (i) no implementation date and/or (ii) no completion date for actions that do not require ongoing implementation (such as the installation of a piece of a equipment) is (are) set forth in the WGMP, the implementation and/or completion date shall be deemed the date of the submission of the WGMP.

b. Waste Gas Minimization Plan: Enforceability. The terms of each WGMP (including Initial, First Updated, and Subsequent Updated WGMPs) submitted under this Appendix are specifically enforceable.

22. Overlapping Requirements: Flare Management Plan Provisions of the NSPS Subpart Ja that are Stayed as of the Date of Lodging. To the extent that currently-stayed provisions of Subpart Ja of the NSPS that prescribe affirmative work practice requirements for flare management plans, *see* 73 Fed. Reg. 78522, 78538-39 (December 22, 2008), are finalized after the Date of Lodging of this Consent Decree, and to the extent compliance with those provisions overlaps with compliance with Paragraphs 18 – 21 and 43, BPP shall comply with the requirements of the finalized Subpart Ja and also comply with each requirement in Paragraphs 18 – 21 and 43 that is not inconsistent with the requirements of a finalized Subpart Ja.

**D. Flare Gas Recovery Systems for all Covered Flares Except the DDU Flare**

23. Dates of Installation and Commencement of Operation of Flare Gas Recovery Systems

a. Except as specifically provided in Subparagraph 23.b, by no later than the following dates for the following Covered Flares or groups of Covered Flares, BPP shall complete installation and commence operation of the following Flare Gas Recovery Systems:

| ID | Covered Flares | Date |
|---|---|---|
| FGRS 1 | South Flare | Upon startup of South Flare |
| FGRS 2 | GOHT | Upon startup of GOHT Flare |
| FGRS 3 | VRU, FCU, Alky | December 31, 2015 |
| FGRS 4 | 4UF, UIU | December 31, 2016 |

b. BPP shall complete the tie-in of the UIU Flare to FGRS 4 by no later than December 31, 2017, and commence recovery of Waste Gas by that time.

24. Design of Flare Gas Recovery Systems

a. Capacity. BPP shall design and install Flare Gas Recovery Systems of the following flow capacities:

| ID | Covered Flares | No. of Compressors | Capacity of Each Compressor (kscfh) | Total System Capacity (kscfh) |
|---|---|---|---|---|
| FGRS 1 | South Flare | 2 | 62.5 | 125 |
| FGRS 2 | GOHT | 2 | 62.5 | 125 |
| FGRS 3 | VRU, FCU, Alky | 4 | 62.5 | 250 |
| FGRS 4 | 4UF, UIU | 3 | 62.5 | 187.5 |

The flow capacities are based on the compression of air with a molecular weight equal to 29.

b. Other. If either FGRS 3 or 4 is shutdown due to a loss of the water level in the seal drum for a period greater than 10 hours in any consecutive 12 month period, then within one year of the date that the 10 hours was exceeded, BPP shall make any necessary changes to prevent any future shutdown of the appropriate FGRS due to a loss of water level in the seal drum.

25. Operation of Flare Gas Recovery Systems. Each Flare Gas Recovery System shall be operated in a manner to minimize Waste Gas to the Flares while ensuring safe refinery operations. BPP shall operate the equipment consistent with good engineering and maintenance practices and in accordance with the manufacturer's specifications.

a. Each compressor shall be capable of starting automatically from an idle mode in a time period and manner consistent with the manufacturer's specifications when necessary to process additional Waste Gas. BPP shall equip the compressors with automatic startup capability by no later than the following dates:

| ID | Covered Flares | Date |
|---|---|---|
| FGRS 1 | South Flare | December 31, 2015 |
| FGRS 2 | GOHT | December 31, 2015 |
| FGRS 3 | VRU, FCU, Alky | Upon startup of FGRS 3 |
| FGRS 4 | 4UF, UIU | Upon startup of FGRS 4 |

b. A compressor in a standby mode and capable of automatic startup shall be considered to be available for operation. Once the compressors at the applicable FGRS are capable of automatic startup as specified in subparagraph 25.a., the FGRS shall have the following number of compressors available for operation at least 95% of the time, based on an 8760-hour rolling average, rolled hourly:

| ID | Covered Flares | No. of Compressors that must be available at least 95% of the time |
|---|---|---|
| FGRS 1 | South Flare | 1 |
| FGRS 2 | GOHT | 1 |
| FGRS 3 | VRU, FCU, Alky | 3 |
| FGRS 4 | 4UF, UIU | 2 |

Each FGRS shall be designed to automatically startup available compressors to process surplus Waste Gas until all available compressors are in operation, including times when a FGRS has all of its installed compressors available for operation. Prior to the installation of automatic startup at FGRS 1 and FGRS 2, BPP shall start compressors manually from standby mode to process surplus Waste Gas within one hour.

c. Additional Requirements Applicable to FGRS 3 and 4

i. At all times, except during the periods described in subparagraphs iii or iv below, BPP shall have one compressor in operations at FGRS 3 and at least one additional compressor either in operation or in a standby mode and capable of automatic startup.

ii. At all times, except during the periods described in subparagraphs iii or iv below, BPP shall have one compressor in operation at FGRS 4.

iii. The requirements of subparagraphs i and ii shall not apply to an FGRS during periods of maintenance on common equipment within that FGRS. These periods of maintenance shall not exceed 336 hours per FGRS on a five year rolling average period, rolled daily. BPP will make best efforts to schedule these maintenance activities during process unit turnarounds and to minimize the generation of Waste Gas during such periods.

iv. The requirements of subparagraph i and ii shall not apply during periods when compressors are shut down consistent with the manufacturer's specifications or good engineering practices to preserve the mechanical integrity of the compressors (for example, as a result of high pressure or temperature).

## E. Limitations on Flaring

26. Limitations on Flaring: Initial Limit. By no later than December 31, 2018, BPP shall comply with the following limitations on flaring at the Refinery:

a. From all Covered Flares and the LPG Flare, BPP shall not flare more than 3.1 MMscfd of Waste Gas on a 30-day rolling average basis, rolled daily; and

b. From all Covered Flares and the LPG Flare, BPP shall not flare more than 2.1 MMscfd of Waste Gas on a 365-day rolling average basis, rolled daily.

Each exceedance of the 30-day rolling average limit or each exceedance of the 365-day rolling average limit shall constitute one day of violation. An exceedance of either or both of the limits shall not prohibit ongoing refinery operations.

27. Limitations on Flaring: Requesting an Increase in the Limit.

a. Once per calendar year commencing no sooner than January 2019, BPP may submit a request to EPA to increase the limitations on flaring set forth in Subparagraphs 26.a and/or 26.b. Any request for an increase in the limitations on flaring shall be based upon an increase in crude capacity that is due to a post-WRMP permitted modification. In any such request, BPP shall propose (a) new limit(s) based upon the following equations:

i. For the Refinery-wide, 30-day rolling average limit:

$$\text{Refinery Flaring} \leq 750{,}000 \text{ scfd} \times \frac{\textit{Whiting Crude Cap.}}{100{,}000 \text{ bpd}} \times \frac{\textit{Whiting Complexity}}{\textit{Industry Avg Complexity}}$$

ii. For the Refinery-wide, 365-day rolling average limit:

$$\text{Refinery Flaring} \leq 500{,}000 \text{ scfd} \times \frac{\textit{Whiting Crude Cap.}}{100{,}000 \text{ bpd}} \times \frac{\textit{Whiting Complexity}}{\textit{Industry Avg Complexity}}$$

b. For purposes of Subparagraph 27.a:

i. The items in italics are variables that will change over time.

ii. The *Whiting Crude Capacity* shall be based on the projected capacity of the Refinery, as reported annually by BPP to the Department of Energy for the year of the request date.

iii. The *Whiting Complexity* shall be calculated in accordance with Equation 1 of Appendix FLR-14. The crude capacity will be the capacity reported by BPP to the Department of Energy for the year that the limit will be in effect. The process unit capacities will be the capacities published the Oil & Gas Journal in barrels per calendar day for the year that the limit will be in effect. BPP shall certify the accuracy of the process unit capacities used to support any request for a change to the limitations on flaring.

iv. The *Industry Average Complexity* shall be calculated in accordance with Equation 2 of Appendix FLR-14.

c. EPA Response to Request. EPA shall evaluate any request under Subparagraph 27.a on the basis of consistency with Subparagraphs 27.a and 27.b. If EPA does not act on BPP's request within 90 days of submission, BPP may invoke the dispute resolution provisions of this Decree. The new limit(s) shall take effect, if ever, beginning on the date that EPA approves the request or a dispute is resolved in BPP's favor. Nothing in this Consent

Decree shall be construed to relieve BPP of an obligation to evaluate, under applicable Prevention of Significant Deterioration and Nonattainment New Source Review requirements, any increase in a Refinery-Wide Limit on Flaring.

28. Meaning and Calculation of "Waste Gas" Flow for Purposes of the Limitation on Flaring. For purposes of the meaning and calculation of "Waste Gas" flow in the limitations on flaring in Paragraphs 26 and 27, the following shall apply:

a. To the extent that BPP has instrumentation capable of measuring the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) in the Waste Gas, the contribution of all measured flows of any of these elements/compounds may be excluded from the Waste Gas flow rate calculation.

b. Waste Gas flows during all periods (including but not limited to normal operations and periods of startup, shutdown, Malfunction, process upsets, relief valve leakages, power losses due to an interruptible power service agreement, and emergencies arising from events within the boundaries of the Refinery), except those expressly described in Subparagraph 28.c and/or the next sentence, shall be included. Waste Gas flows that could not be prevented through reasonable planning and are caused by a natural disaster, act of war or terrorism, or External Power Loss may be excluded from the calculation of flow rate.

c. By no later than 180 days prior to a Cold Startup of the Refinery, BPP may submit to EPA a plan to minimize Waste Gas flaring during a Cold Startup of the Refinery ("Cold Startup Waste Gas Minimization Plan"). If BPP submits a Cold Startup Waste Gas Minimization Plan and operates in accordance with it, BPP may exclude, from the Refinery-Wide 30-day rolling average limit, Waste Gas flows during any Cold Startup that occurs more than 180 days after submission of the Cold Startup Waste Gas Minimization Plan. BPP may not exclude any such flows from the refinery-wide 365-day rolling average limit.

d. Except for hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) contributions to the flow rate that are excluded by virtue of instrumentation measuring these flows, by no later than thirty days after the occurrence of any flow that is not included in a computation, BPP shall submit a written report to EPA that specifically identifies the event that resulted in the exclusion. If the event is a Cold Startup of the Refinery, BPP shall describe dates, durations, and volumes of the flows during the Cold Startup as well as the steps BPP took in compliance with the Cold Startup Waste Gas Minimization Plan. If the event is anything other than a cold startup, BPP shall describe the following: the date(s) and duration(s) of the flows caused by the event; the estimated VOC emissions during the event; whether flows from the event are anticipated to persist after the notice, and if so, for how long; and the measures taken or to be taken to prevent or minimize the flows, including, for future anticipated flow, the schedule by which those measures will be implemented.

### F. Flare Combustion Efficiency Requirements for Covered Flares

29. Emission Standards and Work Practices Applicable to each Covered Flare upon the Date of Entry. By no later than the Date of Entry, BPP shall comply with the following requirements at each Covered Flare:

a. Operation during Emissions Venting. BPP shall operate each Covered Flare at all times when emissions may be vented to it.

b. No Visible Emissions. Except for periods of Startup, Shutdown, and/or Malfunction, BPP shall operate each Covered Flare with no Visible Emissions. Method 22 in 40 C.F.R. Part 60, Appendix A, shall be used to determine compliance with this standard. However, for purposes of this Appendix, Visible Emissions may be determined by either a person certified pursuant to Method 22 or by a video camera.

c. Flame Presence. Except for periods of Malfunction of the Flare, BPP shall operate each Covered Flare with a flame present at all times. BPP shall monitor the presence of the pilot flame using a thermocouple or any other equivalent device to detect the presence of the pilot flame.

d. Exit Velocity. Except for periods of Startup, Shutdown, and/or Malfunction, BPP shall operate each Covered Flare with an Exit Velocity less than 18.3 m/sec (60 ft/sec) on a one-hour block average; provided however, that:

i. If any Covered Flare combusts Vent Gas with a Net Heating Value of greater than 1000 BTU/scf, BPP may operate the Covered Flare with an Exit Velocity equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) on a one-hour block average; and

ii. If any Covered Flare has a maximum permitted velocity ($V_{max}$), BPP may operate the Covered Flare with an Exit Velocity less than $V_{max}$ provided that it also operates the applicable Flare with an Exit Velocity of less than 122 m/sec (400 ft/sec) on a one-hour block average.

$V_{max}$ shall be calculated in accordance with 40 C.F.R. § 60.18(f)(5). The Unobstructed Cross Sectional Area of the Flare Tip shall be calculated consistent with Appendix FLR-6.

e. Monitoring According to Applicable Provisions. BPP shall comply with all applicable Subparts of 40 C.F.R. Parts 60, 61, or 63 that state how a particular Covered Flare must be monitored.

f. Good Air Pollution Control Practices. At all times, including during periods of Startup, Shutdown, and/or Malfunction, BPP shall implement good air pollution control practices to minimize emissions from each Covered Flare; provided however, that BPP shall not be in violation of this requirement for any practice that this Consent Decree requires BPP to implement after the Date of Lodging for the period between the Date of Lodging and the implementation date or compliance date (whichever is applicable) for the particular practice.

30. Work Practice Standards for each Covered Flare.. By no later than January 31, 2014, for all Covered Flares utilizing the instrumentation and controls required to be installed pursuant to Paragraphs 7 – 13, BPP shall install and operate on each Covered Flare an Automatic Control System that shall:

a. automate the control of the Supplemental Gas flow rate to the respective Flare; and

b. automate the control of the Total Steam Flow Rate to the respective Flare.

31. Exception to Part of the Work Practice Standards in Subparagraph 30.b. BPP manually may override the operation of the Automatic Control System required in Subparagraph 30.b (for control of Total Steam Mass Rate) if the exception in Paragraph 51 applies and/or in order to achieve the following:

a. Stop Smoke Emissions that are occurring;

b. Meet the Net Heating Value requirements of Paragraph 33;

c. Prevent extinguishing the Flare;

d. Protect personnel safety;

e. Stop Discontinuous Wake Dominated Flow; and/or

f. During Startup, Shutdown, or Malfunction of a process unit that feeds the Covered Flare.

32. Operation According to Design. By no later than December 31, 2014, for all Covered Flares, BPP shall operate and maintain each Covered Flare in accordance with its design, except if, and only to the extent that, operation and maintenance of the Covered Flare in conformance with its design conflicts with compliance with one or more of the requirements of this Appendix.

33. Net Heating Value Standards for each Covered Flare

a. *$NHV_{vg}$*. Beginning on the Date of Entry and continuing until the earlier of: (i) termination of this Consent Decree; or (ii) the requirements in 40 C.F.R. §§ 60.18(c)(3)(ii) and 63.11(b)(6)(ii) related to the $NHV_{vg}$ are modified, BPP shall operate each Covered Flare with an $NHV_{vg}$ of greater than or equal to 300 BTU/scf on a three-hour rolling average basis, rolled every fifteen minutes, except as provided in Paragraph 51.

b. *$NHV_{cz\text{-}limit}$*. By no later than December 31, 2014, for all Covered Flares, and except as provided in Paragraph 51, BPP shall calculate an $NHV_{cz\text{-}limit}$ at each Covered Flare no less than every fifteen minutes. Except as provided in Paragraph 51, BPP shall operate each Covered Flare so as to ensure that the Covered Flare's $NHV_{cz}$, on a three-hour rolling average basis, rolled every fifteen minutes, is greater than or equal to its $NHV_{cz\text{-}limit}$ on a three-hour rolling average basis, rolled every fifteen minutes. BPP shall utilize the equations and directives set forth in Appendix FLR-3 to meet the requirements of this Subparagraph.

34. *S/VG* Standards.

a. By no later than December 31, 2014, for all Covered Flares, BPP shall operate each Covered Flare at less than or equal to an *S/VG* of 3.0 on a one-hour rolling average, rolled every five minutes.

b. Exceptions. Notwithstanding the requirements of Subparagraph 34.a, BPP is not subject to the emissions standard in that Subparagraph if the exception in Paragraph 51 applies and/or in order to achieve the following:

i. Stop Smoke Emissions that are occurring;

ii. Meet the Net Heating Value requirements of Paragraph 33;

iii. Prevent extinguishing the Flare; and/or

iv. Protect personnel safety.

35. Prohibition on Discontinuous Wake Dominated Flow or Requirement for Minimum *MFR* for Covered Flares.

a. By no later than December 31, 2014, for all Covered Flares, BPP shall comply with either Subparagraph 35.b. or 35.c. In the first semi-annual report due after the applicable compliance date, BPP shall identify which compliance option it selects for each Covered Flare. BPP may select different alternatives for different Covered Flares and may change its election for any given Covered Flare by providing EPA with 30 days prior notice of the change.

b. Prohibition on Discontinuous Wake Dominated Flow.

i. BPP shall not operate the Covered Flares with Discontinuous Wake Dominated Flow, except for periods not to exceed a total of five minutes during any two consecutive hours. BPP shall add Supplemental Gas as necessary to prevent such instances of Discontinuous Wake Dominated Flow at the Covered Flares.

ii. Prior to the effective date of the prohibition in Subparagraph 35.b.i, for all operators and supervisors with responsibility and/or oversight for the operation of each Covered Flare, BPP shall complete training on the meaning and prevention of Discontinuous Wake Dominated Flow. After the effective date, operators shall monitor the operation of each Covered Flare at intervals appropriate for the weather conditions and service of the Covered Flare in order to comply with the prohibition in Subparagraph 35.b.i.

c. MFR Requirements. MFR shall be calculated in accordance with the equations, conversion factors, MFR constants, MFR measured variables, and MFR calculated variables set forth in Appendix FLR-5. BPP shall either:

i. Maintain a minimum MFR of 0.0030 on a 60 minute rolling average basis, rolled every 5 minutes, at each Covered Flare; or

ii. Propose a Flare-specific MFR. BPP shall submit such a proposal to EPA for approval. In any such proposal, BPP shall demonstrate, using, at a minimum, photographs correlated to MFR, that at the proposed MFR, Discontinuous Wake Dominated Flow will not occur for the Covered Flare that is the subject of the request.

d. Notwithstanding Subparagraphs 35.b and c., BPP shall not be required to add Supplemental Gas at any time that the wind speed at the Refinery is greater than or equal to 35 mph on a 60-minute rolling average basis, rolled every 5 minutes, and/or if the exception in Paragraph 51 applies.

36. <u>98% Combustion Efficiency</u>. By no later than December 31, 2014, for all Covered Flares, BPP shall operate each Covered Flare with a minimum of a 98% Combustion Efficiency at all times when Waste Gases are vented to it. To demonstrate continuous compliance with the 98% Combustion Efficiency, BPP shall operate each Covered Flare within the range of operating parameters set forth in Paragraphs 33 – 35.

37. <u>Inapplicability of Paragraphs 33 – 36</u>. The requirements of Paragraphs 33 – 36 are not applicable to any Covered Flare when the only gas or gases being vented to the Covered Flare is/are Pilot Gas and/or Purge Gas. Pilot Gas and Purge Gas will be considered to be the only gases being vented to those Flares if both of the following conditions are met for the water seal drum that is part of the FGRS associated with the respective Covered Flare:

a. The pressure difference between the inlet pressure and outlet pressure is less than the water seal pressure as set by the static head of water between the opening of the dip tube in the drum and the level-setting weir in the drum; and

b. The water level in the drum is at the level of the weir.

38. <u>Emissions and Combustion Efficiency Testing at Certain Covered Flares: Requirements</u>. In order to evaluate emissions and Flare Combustion Efficiency, BPP shall conduct Passive FTIR testing on the DDU and the Alky Flares by no later than September 1, 2014. By no later than 60 days prior to each test, BPP shall submit an Emissions and Flare Combustion Efficiency Test Protocol in accordance with the general requirements in Appendix FLR-16. BPP shall complete the testing on each Covered Flare within 30 days of commencing the testing of the Flare.

39. <u>Emissions and Combustion Efficiency Testing at Certain Covered Flares: Reporting</u>. By no later than four months after completing the testing required in Paragraph 38, BPP shall submit a report to EPA that sets forth the following:

a. The detailed results of the testing done pursuant to Paragraph 38 that includes minute by minute electronic data in Excel format for all measurements and process data and is consistent with the requirements of Appendix FLR-17;

b. A detailed description of the extent to which the $NHV_{cz}$, affects Combustion Efficiency;

c. A detailed description of the range of the $NHV_{cz}$ that the Covered Flares must be operated at to ensure 98% Combustion Efficiency, taking into consideration variability in Vent Gas flow rate;

d. The "A" Combustion Efficiency Multiplier set forth in FLR-3 for calculating the $NHV_{cz\text{-}limit}$ at which BPP proposes to operate the Covered Flare in order to achieve a Combustion Efficiency of no less than 98% on a continuous basis; and

e. A detailed evaluation of whether the results of the testing at the Covered Flare that is the subject of the report impact the "A" Combustion Efficiency Multiplier for calculating the $NHV_{cz\text{-}limit}$ at the six Covered Flares that will not be subject to Passive FTIR testing.

40. <u>EPA Response to PFTIR Report(s)</u>. EPA shall review the reports and establish the "A" Combustion Efficiency Multiplier for calculating the $NHV_{cz\text{-}limit}$ for the specific Flare that is the subject of the report. The "B" Combustion Efficiency Multiplier set forth in Table 2 of Appendix FLR-3 shall apply according to the terms in that Table. The "A" Combustion Efficiency Multiplier will be based on the results of the testing and a consideration of emissions impacts, and will be set at a point where the limits ensure that a Combustion Efficiency of at least 98% is continuously achieved with a reasonable certainty of compliance. EPA also shall

review whether the results of the testing impact the "A" Combustion Efficiency Multiplier for calculating the $NHV_{cz\text{-}limit}$ at the six Covered Flares that will not be subject to Passive FTIR testing. Disputes arising under this Paragraph shall be resolved in accordance with the dispute resolution provisions of this Decree.

41. Recordkeeping: Timing and Substance. BPP shall comply with the following recordkeeping requirements:

a. By no later than March 31, 2014, for all Covered Flares, BPP shall calculate and record, in accordance with the recording and averaging times required in Paragraph 16, each of the following parameters:

i. Total Steam Volumetric Flow Rate (in scfm) and Total Steam Mass Flow Rate (in lb/hr)

ii. Vent Gas Flow and Mass Rates (in scfm and lb/hour)

iii. S/VG (in lbs steam/lbs Vent Gas)

iv. $NHV_{vg}$ (in BTU/scf)

v. $NHV_{cz}$ (in BTU/scf)

vi. $NHV_{cz\text{-}limit}$ (in BTU/scf)

b. By no later than June 30, 2014, for all Covered Flares, commencing if and when any instrument subject to Paragraph 17 operates at less than 95% in any calendar quarter of the in-service time of the Covered Flare that is being monitored by the respective instrument, BPP shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that BPP took.

c. By no later than January 31, 2014, for all Covered Flares, for compliance with the work practice standards in Paragraph 30: (i) BPP shall record each time it manually overrides its Automatic Control System, including the date, time, duration, reason for the override, and corrective actions that BPP took; and (ii) where the reason for the override was to stop Smoke Emissions that were occurring, BPP shall include a copy of the digital video record (with a time stamp) of the Covered Flare during the period of the manual override.

d. At any time that BPP deviates from the standards in Paragraphs 29, 33 - 36, after the effective date of those standards, BPP shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that BPP took.

e. Recordkeeping: Document Retention. For purposes of this Appendix, and except with respect to the data produced by video cameras required pursuant to Paragraph 13, BPP shall retain all records created pursuant to this Appendix, including the raw data values, in accordance with Part VIII ("Reporting and Recordkeeping") and shall make any such documents available to EPA upon request. BPP shall retain the data recorded by the Video Cameras required pursuant to Paragraph 13 for six months except that BPP shall comply with the data retention requirements in Part VIII for those periods when BPP overrode the Automatic Control System.

**G. <u>LPG Flare Requirements</u>**

42. <u>LPG Flare Requirements: Instrumentation and Monitoring Systems</u>. By no later than one year after the Date of Entry, BPP shall undertake the following for the LPG Flare:

a. Install a flow meter in order to determine the Vent Gas Volumetric and Mass Flow Rates to the LPG Flare. The air flow rate shall be determined from the fan speed on the Assist Air blower.

b. Install a Variable Speed Motor on the LPG Flare's Assist Air blower;

c. Install a control system that will automate the control of the Variable Speed Motor on the LPG Flare's Assist Air blower to enable BPP to comply with the standard set forth in Paragraph 45; and

d. In the semi-annual report required under Paragraph 98 of Part VIII that is the first one due after one year after the Date of Entry of this Consent Decree, provide a detailed description of the installations made in compliance with Subparagraphs 42.a. and 42.b, including the specific models and manufacturers.

43. <u>Waste Gas Minimization for LPG Flare</u>. Commencing thirty days after the installation of the flow meter required pursuant to Subparagraph 42.a, and continuing through December 31, 2014, BPP will identify and implement Prevention Measures for the minimization of Vent Gas flow to the LPG Flare. In the first semi-annual report due after the installation of the flow meter required pursuant to Subparagraph 42.a and continuing through the semi-annual report due in January of 2015, BPP will provide, for the time period covered by the semi-annual report, the following information: (i) the volumetric flow of Waste Gas, in scfm, on a 30-day rolling average, and the mass flow rate, in pounds per hour, on a 30-day rolling average, vented to the LPG Flare; (ii) the Prevention Measures implemented for the reporting period; and (iii) the Prevention Measures expected to be implemented in the future, together with a schedule for prompt implementation.

44. <u>Emission Standards Applicable to the LPG Flare</u>. By no later than one year after the Date of Entry, BPP shall comply with each of the requirements in Paragraph 29 at the LPG Flare, except that, with respect to Exit Velocity, BPP shall comply with the requirements in 40 C.F.R. § 60.18(c)(5) and not those in Subparagraph 29(d).

45. <u>Standard for $\dot{m}_{air-asst}/\dot{m}_{air-stoich-vg}$</u>. By no later than one year after the Date of Entry of this Consent Decree and continuing through to either: (i) the date that EPA sets a new limit

pursuant to either Subparagraph 48.d or 49.b; or (ii) the termination of this Consent Decree, whichever is applicable, BPP shall operate the LPG Flare so as to ensure that $\dot{m}_{air\text{-}asst}$ < 10 x $\dot{m}_{air\text{-}stoich\text{-}vg}$, on a one-hour rolling average, rolled every five minutes. BPP shall utilize the equations and directives set forth in Appendix FLR-15 to meet the requirements of this Paragraph. Notwithstanding the requirements of this Paragraph, BPP is not subject to the standard set forth in this Paragraph if the exception in Paragraph 51 applies and/or in order to (1) stop Smoke Emissions that are occurring, (2) prevent extinguishing the Flare, (3) protect personnel safety, and /or (4) prevent Wake Dominated Flow.

46. Operation According to Design. By no later than one year after the Date of Entry of this Consent Decree, BPP shall operate and maintain the LPG Flare in accordance with its design, except if, and only to the extent that, operation and maintenance of the LPG Flare in conformance with its design conflicts with compliance with one or more of the requirements of this Appendix.

47. Testing Depending on Annual Average Vent Gas Volumetric Flow Rate to the LPG Flare: Determining the Annual Average Vent Gas Flow Rate of the LPG Flare for Calendar Year 2015. By no later than March 31, 2016, BPP shall determine the annual average Vent Gas Flow Rate, in scfm, for the LPG Flare for the calendar year 2015. To determine the annual average Vent Gas Flow Rate for calendar year 2015, BPP shall use the Vent Gas Flow Rate data gathered in 2015. All flows shall be included.

48. Testing Depending on Annual Average Vent Gas Volumetric Flow Rate to the LPG Flare: Consequences if the Annual Average Vent Gas Flow Rate for 2015 for the LPG Flare Equals or Exceeds Certain Figures.

a. Passive FTIR Testing. If the annual average Vent Gas Flow Rate of the LPG Flare for 2015 equals or exceeds 35 scfm (if the Whiting Refinery is located in an area designated as non-attainment for the eight-hour ozone standard at the end of calendar year 2015) or 70 scfm (if the Whiting Refinery is located in an area designated as attainment for the eight-hour ozone standard at the end of calendar year 2015), then, by no later than September 30, 2016, BPP shall conduct Passive FTIR testing on the LPG Flare. By no later than 60 days prior to the testing, BPP shall submit an Emissions and Flare Combustion Efficiency Test Protocol in accordance with the general requirements in Appendix FLR-16. BPP shall complete the testing on the LPG Flare within 30 days of commencing testing.

b. Passive FTIR Report. By no later than four months after completing the testing required in Subparagraph 48.a, BPP shall submit a report to EPA for approval that sets forth the following:

i. The detailed results of the testing that include minute by minute electronic data in Excel format for all measurements and process data and is consistent with the requirements of Appendix FLR-17 that are relevant to an Air-Assisted Flare;

ii. A detailed description of the extent to which the $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ affects Combustion Efficiency;

iii. A detailed description of the range of the $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$, that the Covered Flares must be operated at to ensure 98% Combustion Efficiency or as high an efficiency as reliably obtainable, taking into consideration variability in Vent Gas flow rate.

iv. The maximum $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ at which BPP proposes to operate the LPG Flare in order to achieve a Combustion Efficiency as high as reliably obtainable; and

v. A proposed Combustion Efficiency applicable to the LPG Flare that is as high as reliably obtainable.

c. Compliance with Proposed Operating Limits in Passive FTIR Report. Unless and until EPA establishes different limits under Subparagraph 48.d, BPP shall comply with the operating limits that it proposes pursuant to Subparagraph 48.b.iv.

d. EPA-Established Operating Limits and Combustion Efficiency. Based on all of the available information from the testing conducted pursuant to Subparagraph 48.a and the report submitted pursuant to Subparagraph 48.b, EPA shall establish a $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ that will enable BPP to achieve a Combustion Efficiency as high as reliably obtainable. EPA also shall establish a Combustion Efficiency for the LPG Flare that is reliably obtainable, but shall be no higher than 98%. Within 60 days of receiving written notice establishing such limits, BPP shall comply with the $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ and Combustion Efficiency established by EPA.

e. Exceptions to Compliance with Limits in Subparagraphs 48.c and 48.d. BPP shall not be subject to the limits in Subparagraphs 48.c. or 48.d if the exception in Paragraph 51 applies and/or in order to achieve the following:

*(1)* Stop Smoke Emissions that are occurring;

*(2)* Meet Net Heating Value requirements;

*(3)* Prevent extinguishing the Flare; and/or

*(4)* Protect personnel safety.

49. Testing Depending on Annual Average Vent Gas Volumetric Flow Rate to the LPG Flare: Consequences if the Annual Average Vent Gas Flow Rate for 2015 for the LPG Flare is Below Certain Figures.

a. Annual Redetermination of the Annual Average Vent Gas Flow Rate. If the annual average Vent Gas Flow Rate of the LPG Flare for 2015 is less than 35 scfm (if the Whiting Refinery is located in an area designated as non-attainment for the eight-hour ozone standard at the end of calendar year 2015) or 70 scfm (if the Whiting Refinery is located in an area designated as attainment for the eight-hour ozone standard at the end of calendar year 2015), then for the duration of the Consent Decree, on an annual basis in the first calendar quarter of each year, BPP shall determine the average annual Vent Gas Flow Rate, in scfm, for the LPG Flare for the prior calendar year.

b. Consequences if the Annual Average Vent Gas Flow Rate Equals or Exceeds Certain Limits. If, during an annual review, the annual average Vent Gas Flow Rate for the LPG Flare for the prior calendar year equals or exceeds 35 scfm (if the Whiting Refinery is located in an area designated as non-attainment for the eight-hour ozone standard at the end of prior calendar year) or 70 scfm (if the Whiting Refinery is located in an area designated as attainment for the eight-hour ozone standard at the end of prior calendar year), then BPP shall conduct, complete, and comply with the requirements set forth in Subparagraphs 48.a – 48.c by no later than September 30 of the applicable year. EPA thereafter will establish a $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ and Combustion Efficiency pursuant to Subparagraph 48.d

c. Reporting. If as a result of an annual review of the annual average Vent Gas Flow Rate for the LPG Flare, BPP is not required to conduct Passive FTIR Testing, BPP shall report the results of the annual review in the first semi-annual report that is due after the annual review has been completed. If as a result of an annual review, BPP is required to conduct Passive FTIR Testing, BPP shall notify EPA by no later than April 30 of the applicable year of the results of the review and the schedule that it will follow to comply with the requirements in Subparagraphs 48.a and 48.b.

50. Testing Depending on Annual Average Vent Gas Volumetric Flow Rate to the LPG Flare: Recordkeeping. If at any time under this Paragraph, BPP is required to undertake Passive FTIR Testing, then commencing within 90 days after submitting its Passive FTIR Report, BPP shall comply with all applicable recordkeeping requirements of Paragraph 41, but "Assist Air" or "$\dot{m}_{air\text{-}asst}$" shall be substituted for any reference to "Total Steam" or "*S*" in Paragraph 41.

## H. Exception for Instrument Downtime

51. A failure to comply with the work practices or standards in Paragraphs 30.b, 33.a, 33.b, 34.a, 35.b, 35.c, 45, 48.c, or 48.d shall not constitute a violation of such work practice or standard if the noncompliance results from downtime of instruments or equipment due to the following:

a. Malfunction of an instrument, for an instrument needed to meet the requirement(s);

b. Maintenance following instrument Malfunction, for an instrument needed to meet the requirement(s);

c. Scheduled maintenance of an instrument in accordance with the manufacturer's recommended schedule, for an instrument needed to meet the requirement; and/or

d. Quality Assurance/Quality Control activities on an instrument needed to meet the requirement.

Provided, however, that this exception shall no longer be applicable if the activities in Subparagraphs 51a. through d. exceed 110 hours in any calendar quarter for any instrument. The calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VI of Appendix FLR-11.

## I. Control of Reportable Flaring Incidents

52. Flares Subject to Subsection I. Each Covered Flare, the LPG Flare, and the SRU Flare are subject to the requirements of Subsection I.

53. Dates of Applicability of the Requirements in Subsection I. The requirements of Subsection I shall apply to Reportable Flaring Incidents that occur on and after the following dates:

| Type of Reportable Flaring Incident | Applicability Date |
|---|---|
| AG Flaring Incident | Date of Entry |
| Tail Gas Incident (Triggers 1 and 2) | Date of Entry |
| HC Flaring Incident – Trigger 1 | Date of Entry |
| HC Flaring Incident – Trigger 2 | Date of Submission of First Updated Waste Gas Minimization Plan |

54. Root Cause Analysis, Internal Reporting, and Recordkeeping. Except as expressly provided in Paragraph 56, by no later than 45 days following the end of a Reportable Flaring Incident, BPP shall conduct an investigation into the Root Cause(s) of the Incident and prepare and keep as a record an internal report that shall include, at a minimum, the following:

a. The date and time that the Reportable Flaring Incident started and ended. To the extent that the Reportable Flaring Incident involved multiple releases either within a twenty-four (24) hour period or within subsequent, contiguous, non-overlapping twenty-four (24) hour periods, BPP shall set forth the starting and ending dates and times of each release;

b. An estimate of the volume of gases flared (or combusted, for Tail Gas Incidents – Trigger 2), the quantity of $SO_2$ and VOCs emitted, and the calculations that were used to determine these values;

c. The steps, if any, that BPP took to limit the duration of the Reportable Flaring Incident, the volume of gas flared or combusted, and the quantity of $SO_2$ and VOC emissions associated therewith;

d. A detailed analysis that sets forth the Root Cause, including all contributing causes, of the Reportable Flaring Incident, to the extent determinable;

e. An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of a Reportable Flaring Incident resulting from the same Root Cause, or contributing causes, in the future. The analysis shall discuss all reasonable alternatives, if any, that are available, and the probable effectiveness and cost of the alternatives. Possible design and operation and maintenance changes shall be evaluated. If BPP concludes that corrective action(s) is/are available, the report will include a description of the action(s) and, if not already completed, a schedule for its (their) implementation, including proposed commencement and completion dates. If BPP concludes that corrective action is not available, the report will explain the basis for that conclusion;

f. To the extent that the investigation of the causes and/or possible corrective actions still are underway 45 days after the end of a Reportable Flaring Incident, a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Paragraph will be completed; provided however, that if the investigation of the causes and/or possible corrective actions still are underway 90 days after the end of a Reportable Flaring Incident and if BPP has not sought by that time an extension of time to complete the investigation, stipulated penalties for failing to timely complete the investigation shall apply but BPP shall retain the right to dispute, under the dispute resolution provisions of this Consent Decree, any demand for stipulated penalties that was issued as a result of BPP's failure to timely complete the investigation. Nothing in this Subparagraph shall be deemed to excuse BPP from its investigation, reporting, recordkeeping, and corrective action obligations of this Subsection H for any Reportable Flaring Incident that occurs after a Reportable Flaring Incident for which BPP has requested an extension of time.

g. To the extent that completion of the implementation of corrective action(s), if any, is not finalized by 45 days after the end of a Reportable Flaring Incident, then BPP will include in each semi-annual report due under Part VIII of this Decree, an identification of the corrective action(s) taken or still to be taken and the dates of commencement and completion, or proposed completion, of implementation.

h. <u>For Acid Gas and Tail Gas Incidents only</u>: A statement that: (i) specifically identifies each of the grounds for stipulated penalties in Paragraphs 61, 62, and 63 of this Appendix and describes whether the Acid Gas Flaring or Tail Gas Incident falls under any of those grounds; (ii) if an Acid Gas Flaring or Tail Gas Incident falls under Paragraph 65 of this Decree, describes which Subparagraph -- 63.a or 63.b -- applies and why; and (iii) if an Acid Gas Flaring or Tail Gas Incident falls under either Paragraph 62 or 63.b, states whether or not BPP asserts a defense, and if so, a description of the defense. BPP shall not be required to comply with the requirements of this Subparagraph if BPP chooses, instead, to submit a payment of stipulated penalties in the nature of settlement at the time that it submits the semi-annual report, *see* Paragraph 57, that includes the report completed under this Paragraph. Such payment of stipulated penalties shall not constitute an admission of liability, nor shall it raise any presumption whatsoever about the nature, existence or strength of BPP's potential defenses

55. Corrective Action Implementation.

a. In response to any Reportable Flaring Incident, BPP shall take, as expeditiously as practicable, such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause, including all contributing causes, of that Reportable Flaring Incident.

b. EPA does not, by its agreement to the entry of this Consent Decree or by its failure to object to any corrective action that BPP may take in the future, warrant or aver in any manner that any of BPP's corrective actions in the future will result in compliance with the provisions of the Clean Air Act or its implementing regulations. Notwithstanding EPA's review of any plans, reports, corrective actions or procedures under this Subsection I, BPP shall remain solely responsible for non-compliance with the Clean Air Act and its implementing regulations. Nothing in this Paragraph shall be construed as a waiver of EPA's rights under the Clean Air Act and its regulations for future violations of the Act or its regulations.

c. After a review of any report required by Paragraph 54 and submitted as required by Paragraph 57, EPA shall notify BPP in writing of: (i) any deficiencies in the corrective actions listed in the findings; and/or (ii) any objections to the schedules of implementation of the corrective actions and explain the basis for EPA's objections. If BPP has not commenced a corrective action that EPA has identified as deficient, BPP will implement an alternative or revised corrective action or implementation schedule based on EPA's comments. If a corrective action that EPA has identified as deficient has already commenced or is already completed, then BPP is not obligated to implement corrective action identified by EPA for that Reportable Flaring Incident provided that BPP completes the corrective action that it has identified and commenced.

d. For purposes of Paragraph 55.c, "commenced" means BPP has: (i) commenced actual physical construction on the corrective action; or (ii) completed the engineering design for the corrective action and has purchased or entered into a binding contractual obligation (with adverse consequences from its breach) to purchase equipment necessary to implement the corrective action. However, BPP will be put on notice that such corrective action is deficient and not acceptable for remedying any subsequent, similar Root Cause(s) of any Reportable Flaring Incident. If EPA and BPP cannot agree on the appropriate corrective action(s) or implementation schedule(s), if any, to be taken in response to a Root Cause, either party may invoke the Dispute Resolution provisions of Part XIV of the Consent Decree.

e. Nothing in this Subsection I shall be construed to limit the right of BPP to take such corrective actions as it deems necessary and appropriate immediately following a Reportable Flaring Incident or in the period during preparation and review of any reports required under this Paragraph.

56. Exceptions to the Requirements in Paragraphs 54 and 55 for Certain HC Flaring Incidents. The requirements of Paragraphs 54 and 55 shall not apply to the following Hydrocarbon Flaring Incidents:

a. For the six (6) month period after the installation of a Flare Gas Recovery System (that is, during the time in which the FGRS is being commissioned), for each Root Cause, including all contributing causes, that is directly related to the commissioning of the FGRS;

b. For each Root Cause, including contributing causes, that BPP previously had analyzed as attributable to the startup or shutdown of a unit; in such cases, BPP may rely upon and cross-reference the prior analysis.

57. Submitting the Internal Flaring Incident Reports to EPA and IDEM. In each semi-annual report due under Part VIII of this Consent Decree, BPP shall include copies of each Reportable Flaring Incident report that BPP was required to prepare in compliance with Paragraph 54 during the six month period that the semi-annual report covers. Each semi-annual report also shall include summary of each of the Incidents including the following:

a. Date;

b. Duration;

c. Amount of $SO_2$ and VOC released;

d. Root Cause(s);

e. Corrective Action(s) completed;

f. Corrective Action(s) still outstanding;

g. Stipulated penalties, if any, due

h. An analysis of any trends identified by BPP in terms of the number of Incidents, the Root Causes, or the types of Corrective Action

58. Calculating $SO_2$ Emissions. The equations for calculating sulfur dioxide emissions from Reportable Flaring Incidents are set forth in Appendix FLR-18.

59. Reserved.

**J. Stipulated Penalties for Acid Gas Flaring Incidents and Tail Gas Incidents**

60. An Acid Gas Flaring Incident or a Tail Gas Incident, in and of itself, may subject BPP to stipulated penalties under this Subsection J. A Hydrocarbon Flaring Incident, in and of itself, will not subject BPP to stipulated penalties under this Subsection J. However, a failure by

BPP to comply with all other provisions of Subsection I, including Root Cause Analysis, internal reporting, recordkeeping, and corrective action, may subject BPP to stipulated penalties regardless of whether the type of Reportable Flaring Incident was an Acid Gas, Tail Gas or Hydrocarbon Flaring Incident. Stipulated penalties for those other potential violations are found in Part X of this Decree ("Stipulated Penalties").

61. The stipulated penalties in Paragraph 66 of this Appendix shall apply to each Acid Gas Flaring or Tail Gas Incident for which the Root Cause is one or more of the following acts, omissions, or events:

a. Error resulting from careless operation by the personnel charged with responsibility for the sulfur recovery plant, the Tail Gas Unit, or process units upstream of the sulfur recovery plant;

b. Failure to follow written procedures; or

c. A failure of equipment that is due to a failure by BPP to operate and maintain that equipment in a manner consistent with good engineering practice.

62. If the Root Cause of the Acid Gas Flaring or Tail Gas Incident is not identified in Paragraph 61, then, except as provided in Paragraph 64, stipulated penalties in Paragraph 66 of this Appendix shall apply if the Acid Gas Flaring or Tail Gas Incident:

a. Results in emissions of $SO_2$ at a rate greater than twenty (20.0) pounds per hour continuously for three (3) consecutive hours or more and BPP failed to take any action during the Acid Gas Flaring Incident to limit the duration and/or quantity of $SO_2$ emissions associated with such incident; or

b. Causes the total number of Acid Gas Flaring Incidents in a rolling twelve (12) month period to exceed five (5).

63. With respect to any Acid Gas Flaring or Tail Gas Incident that does not fall under either Paragraph 61 or 62, the following provisions shall apply:

a. <u>First Time</u>: If the Root Cause of the Acid Gas Flaring or Tail Gas Incident was not a recurrence of the same Root Cause that resulted in a previous Acid Gas Flaring or Tail Gas Incident that occurred since the Date of Entry, then:

i. If the Root Cause of the Acid Gas Flaring or Tail Gas Incident was sudden, infrequent, and not reasonably preventable through the exercise of good engineering practice, then that cause shall be designated as an agreed-upon Malfunction for purposes of reviewing subsequent Acid Gas Flaring and Tail Gas Incidents; the stipulated penalty provisions of Paragraph 66 shall not apply.

ii. If the Root Cause of the Acid Gas Flaring Incident was sudden and infrequent, but was reasonably preventable through the exercise of good engineering practice, then BPP shall implement corrective action(s) pursuant to Paragraph 55, but the stipulated penalty provisions of Paragraph 66 shall not apply.

b. Recurrence: If the Root Cause is a recurrence of the same Root Cause that resulted in a previous Acid Gas Flaring or Tail Gas Incident that occurred since the Date of Entry, then BPP shall be liable for stipulated penalties under Paragraph 66 unless:

i. The AG Flaring or Tail Gas Incident resulted from a Malfunction or other defense that BPP successively asserts; or

ii. The Root Cause previously was designated as an agreed-upon Malfunction under Paragraph 63.a.i; or

iii. The Acid Gas Flaring or Tail Gas Incident had as its Root Cause the recurrence of a Root Cause for which BPP had previously developed, or was in the process of developing, a corrective action plan and for which BPP had not yet completed implementation.

64. Defenses. By definition, the Root Causes identified in Paragraph 61 are not Malfunctions or Force Majeure events, and therefore, BPP shall have not have a Malfunction or Force Majeure defense to a demand for stipulated penalties that is based on the Root Causes identified in Paragraph 61. For Incidents under Paragraphs 62 - 63, BPP may assert a Malfunction or Force Majeure defense. In addition, in any dispute under Paragraphs 62 and 63, BPP may also assert a Startup and/or Shutdown defense, but the United States shall be entitled to assert that such defenses are not available.

65. If no Acid Gas Flaring Incident (other than ones caused by a Malfunction or Force Majeure) and no Tail Gas Incident (other than ones caused by a Malfunction or Force Majeure) occur for a rolling 36-month period, then the stipulated penalty provisions of Paragraph 68 shall no longer apply. EPA may elect to reinstate the stipulated penalty provisions if the Refinery has an Acid Gas Flaring Incident which would otherwise be subject to stipulated penalties. EPA's decision shall not be subject to dispute resolution. Once reinstated, the stipulated penalty provision shall thereafter apply to future Acid Gas Flaring and Tail Gas Incidents and shall continue for the remaining life of this Consent Decree.

66. Stipulated Penalty Table for Acid Gas Flaring and Tail Gas Incidents

a. The following table shall be used to calculate stipulated penalties that become due under Paragraphs 61 - 64:

| Tons of $SO_2$ Emitted in Acid Gas Flaring Incident | Length of Time from Commencement of Flaring within the Acid Gas Flaring Incident to Termination of Flaring within the Acid Gas Flaring Incident is 3 hours or less | Length of Time from Commencement of Flaring within the Acid Gas Flaring Incident to Termination of Flaring within the Acid Gas Flaring Incident is greater than 3 hours but less than or equal to 24 hours | Length of Time from Commencement of Flaring within the Acid Gas Flaring Incident to Termination of Flaring within the Acid Gas Flaring Incident is greater than 24 hours |
|---|---|---|---|
| 5 Tons or Less | $500 per ton | $750 per ton | $1000 per ton |
| Greater than 5 tons, but less than or equal to 15 tons | $1,200 per ton | $1,800 per ton | $2,300 per ton, up to, but not exceeding, $32,500 in any one calendar day |
| Greater than 15 tons | $1,800 per ton, up to, but not exceeding, $32,500 in any one calendar day | $2,300 per ton, up to, but not exceeding, $32,500 in any one calendar day | $32,500 in any one calendar day |

b. For purposes of calculating stipulated penalties pursuant to this Paragraph, only one cell within the matrix shall apply. Thus, for example, for an Acid Gas Flaring Incident in which the Acid Gas Flaring starts at 1:00 p.m. and ends at 3:00 p.m., and for which 14.5 tons of $SO_2$ are emitted, the penalty would be $17,400 (14.5 x $1,200); the penalty would not be $13,900 [(5 x $500) + (9.5 x $1200)].

c. For purposes of determining which column in the table applies under circumstances in which Acid Gas Flaring occurs intermittently during an Acid Gas Flaring Incident, the Acid Gas Flaring shall be deemed to commence at the time that the Acid Gas Flaring that triggers the initiation of an Acid Gas Flaring Incident commences, and shall be deemed to terminate at the time of the termination of the last episode of Acid Gas Flaring within the Acid Gas Flaring Incident. Thus, for example, for Acid Gas Flaring within an Acid Gas Flaring Incident that (i) starts at 1:00 p.m. on Day 1 and ends at 1:30 p.m. on Day 1; (ii) recommences at 4:00 p.m. on Day 1 and ends at 4:30 p.m. on Day 1; (iii) recommences at 1:00 a.m. on Day 2 and ends at 1:30 a.m. on Day 2; and (iv) no further Acid Gas Flaring occurs within the Acid Gas Flaring Incident, the AG Flaring within the AG Flaring Incident shall be deemed to last 12.5 hours – not 1.5 hours – and the column for Acid Gas Flaring of "greater than 3 hours but less than or equal to 24 hours" shall apply.

**K. Miscellaneous**

67. Temporary-Use Flares.

a. Applicability. The provisions of this Paragraph shall apply to Temporary-Use Flares.

b. Distinction between Planned and Unplanned Outages of Covered Flares. For purposes of this Paragraph, a "planned" outage of a Covered Flare shall mean an outage that is scheduled 30 days or more in advance of the outage. An "unplanned" outage is an outage that either is scheduled less than 30 days in advance or is unscheduled.

c. 504 hours or less. For any planned or unplanned outage of a Covered Flare that BPP knows or reasonably anticipates will result in 504 hours or less of downtime on a rolling 1095 day average period, BPP shall make good faith efforts to ensure that the Temporary-Use Flare that replaces the Covered Flare complies with all of the requirements of this Consent Decree that are applicable to the Covered Flare that the Temporary-Use Flare replaces.

d. More than 504 hours.

i. Planned. For any planned outage of a Covered Flare that BPP knows or reasonably can anticipate will last 504 hours or more on a rolling three-year average period, BPP shall ensure that the Temporary-Use Flare complies with all of the requirements of this Appendix related to the Covered Flare that it replaces as of the date that the Temporary-Use Flare is placed into service.

ii. Unplanned. For any unplanned outage of a Covered Flare that, in advance of the outage, BPP cannot reasonably anticipate will last longer than 504 hours, BPP shall ensure that the Temporary-Use flare complies with all of the requirements of this Appendix related to the Covered Flare that it replaces by no later than 30 days after the date that BPP knows or reasonably should have known that the outage would last 504 hours or more.

e. Recordkeeping. BPP shall keep records sufficient to document compliance with the requirements of this Paragraph any time it uses a Temporary-Use flare.

68. Miscellaneous. Whenever this Appendix requires compliance within a certain number of "months" after a triggering event, the compliance obligation commences on the anniversary of the numerical date that triggers the obligation. For example, if compliance is required by no later than three months after the submission of a particular document, and if the document is submitted on March 23, 2010, the compliance obligation commences on June 23, 2010.

**L. NSPS Subparts A, J, and Ja Applicability for Flares**

69. NSPS Subparts A and J.

a. Beginning on the Date of Entry, and continuing until they become subject to the provision of 40 C.F.R. Part 60, Subpart Ja under Paragraph 70, the DDU and LPG Flares will each continue to be an "affected facility" within the meaning of Subparts A and J of 40

C.F.R. Part 60, will be subject to Subparts A and J, and will comply with the requirements of Subparts A and J, including all monitoring, recordkeeping, reporting, and operating requirements.

b. Beginning upon the date of initial startup, and continuing until they become subject to the provisions of 40 C.F.R. Part 60, Subpart Ja under Paragraph 70, the South and GOHT Flares shall each be an "affected facility" within the meaning of Subparts A and J of 40 C.F.R. Part 60. No later than 180 Days after the date of initial startup, and continuing until they become subject to the provisions of 40 C.F.R. Part 60, Subpart Ja under Paragraph 70, the South and GOHT Flares shall comply with the requirements of Subparts A and J, related to Flares, including all monitoring, recordkeeping, reporting, and operating requirements.

c. Beginning on the dates by which they are required to be tied into a FGRS under Paragraph 23 and continuing until they become subject to the provisions of 40 C.F.R. Part 60, Subpart Ja under Paragraph 70, the VRU, Alky, FCU, UIU and 4UF Flares shall each be an "affected facility" within the meaning of Subparts A and J of 40 C.F.R. Part 60, will be subject to Subparts A and J, and will comply with the requirements of Subparts A and J, including all monitoring, recordkeeping, reporting, and operating requirements.

70. <u>NSPS Subpart Ja</u>.

a. The DDU and the LPG Flare will each be an "affected facility" within the meaning of Subpart Ja of 40 C.F.R. Part 60, will be subject to Subpart Ja, and will comply with the requirements of Subpart Ja, including all monitoring, recordkeeping, reporting, and operating requirements, by the later of the Date of Entry or the date of compliance required by Subpart Ja when the stay of Subpart Ja no longer is in effect. The other Covered Flares will each be an "affected facility" within the meaning of Subpart Ja of 40 C.F.R. Part 60, will be subject to Subpart Ja, and will comply with the requirements of Subpart Ja, including all monitoring, recordkeeping, reporting, and operating requirements, by the later of: (i) the date by which that Flare is required to be tied into a FGRS under Paragraph 23; or (ii) the date of compliance required by Subpart Ja when the stay of Subpart Ja no longer is in effect.

b. For each Covered Flare and the LPG Flare, upon the date that each such flare becomes an "affected facility" as set forth in Subparagraph 70.a, the requirements in Sections I. and J. of this Appendix will no longer be applicable to such flare.

**M. <u>Decommissioning the SRU Flare</u>**

71. <u>SRU Flare</u>. By no later than 180 days after initial startup of the new Coker, BPP shall permanently decommission the SRU Flare. For purposes of this Paragraph, "permanently decommissioned" means the waste gas piping has been disconnected from the SRU Flare by the installation of a welded blind on the piping. By no later than six months after permanently decommissioning the SRU Flare, BPP shall submit a request to IDEM to amend the Title V permit to reflect the permanent disconnection of this flare.

## N. Reporting Requirements for this Appendix

72. Monitoring Instrument/Equipment Downtime, Override of Automatic Control System, and Emissions Exceedances. On and after the date of applicability of any work practice or standard, BPP shall provide a summary of the following, per Covered Flare and the LPG Flare per calendar quarter (hours shall be rounded to the nearest tenth):

a. Monitoring Instrument/Equipment Downtime. The total number of hours of downtime of each monitoring instrument/equipment required pursuant to Paragraphs 7-9, 11-13 (and, if applicable, Paragraph 42), expressed as both an absolute number and a percentage of time the Covered Flare and the LPG Flare that the instrument/equipment monitors is available for operation;

b. Monitoring Instrument/Equipment Downtime. If the total number of hours of downtime of any monitoring instrument/equipment required pursuant to Paragraphs 7-9, 11-13 (and, if applicable, Paragraph 42), exceeds 110 hours in any calendar quarter, an identification of the periods of downtime by date, time, cause (including Malfunction or maintenance), and, if the cause is asserted to be a Malfunction, the corrective action taken;

c. Override of Automatic Control System. The total number of hours in which BPP overrode the Automatic Control System required in Paragraph 30 (and, if applicable, Paragraph 42), expressed as both an absolute number of hours and a percentage of time the Covered Flare and the LPG Flare was available for operation; provided however, that for any hour identified, the report shall describe either or both of the following: (i) if the reason for the override was one of the exceptions identified in Paragraph 31, a statement of which exception; or (ii) if the total number of hours in which the Automatic Control System was overrode was less than 110 hours and was caused by one or more of the exceptions identified in Paragraph 51, a statement to that effect;

d. Override of Automatic Control System. If the reason for the override was not one of the exceptions set forth in Paragraphs 31 or 45 or if the total number of hours in which the Automatic Control System was overrode exceeds 110 hours in any calendar quarter, an identification of the periods of override by the date, time, duration, reason for the override, and corrective actions taken;

e. Inapplicability of Emissions Standards. The total number of hours in which the requirements of Paragraphs 33-36 were not applicable because the only gas or gases being vented was/were Pilot Gas and/or Purge Gas, expressed as both an absolute number of hours and a percentage of time the Covered Flare and/or the LPG Flare was available for operation; for purposes of Subparagraphs 72.f. and 72.g, all remaining hours shall be termed "Hours of Applicability";

f. Exceedances of Standards. During the Hours of Applicability, the total number of hours of exceedances of the standards in Paragraphs 33.b, 34.a, 34.b, 36 (and, if applicable, Paragraph 45), expressed as both an absolute number of hours and a percentage of time the Covered Flare and the LPG Flare was available for operation; provided however, that if the exceedance of these standards was less than 110 hours in the calendar quarter and was due to one or more of the exceptions set forth in Paragraph 51, the report shall so note;

g. Exceedances of Standards. During the Hours of Applicability, if the exceedance of the standards in Paragraphs 33.b, 34.a, 34.b, 36 (or, if applicable, Paragraph 45), was not due to one of the exceptions in Paragraph 51, or if the exceedance was due to one or more of the exceptions in Paragraph 51 but the total number of hours caused by the exceptions in Paragraph 51 was greater than 110, an identification of each averaging period that exceeded the standard, by time and date; the cause of the exceedance (including startup, shutdown, maintenance, or Malfunction), and if the cause is asserted to be a Malfunction, an explanation and any corrective actions taken; and

h. Flaring Limitations Exceedances.

i. For any Waste Gas flows that are excluded from the calculation of flow rate because they are asserted to be based on one or more of the excludible events identified in Paragraph 28.b, the information required in Paragraph 28.d;

ii. An identification of each calendar day in which the limitations on flaring set forth in Paragraph 26 (or 27, if applicable) were violated;

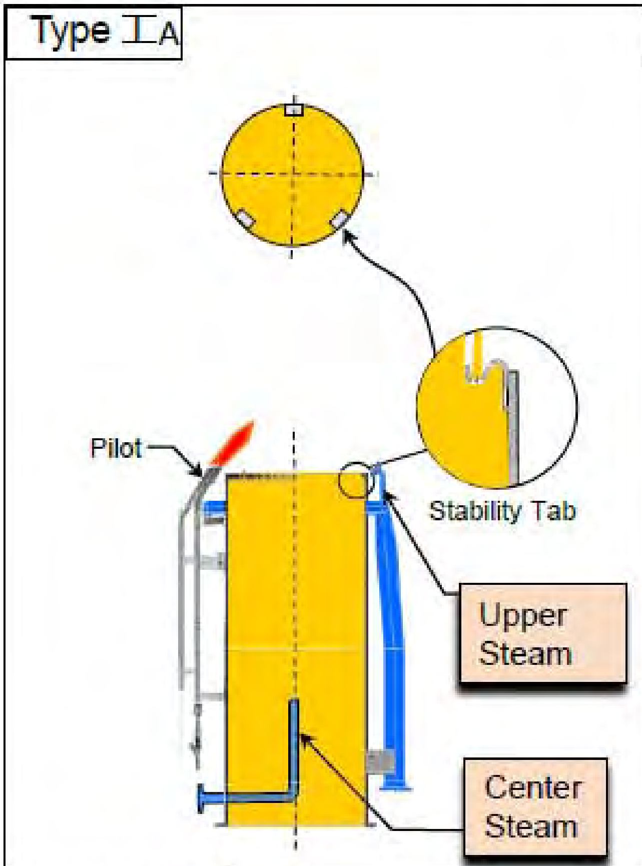
iii. The cause of the exceedance;

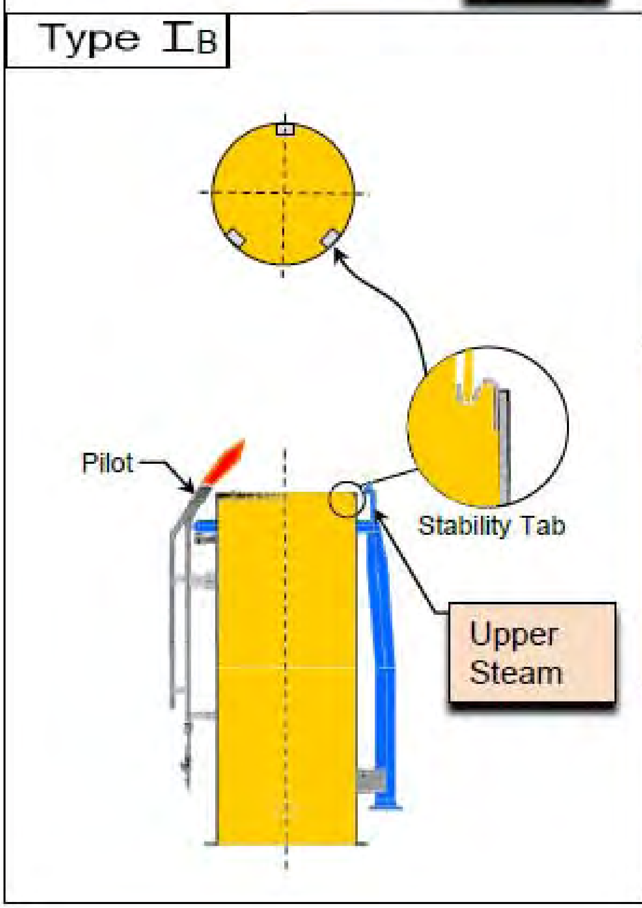
iv. If the cause is asserted to be a Malfunction, an explanation and any corrective actions taken;

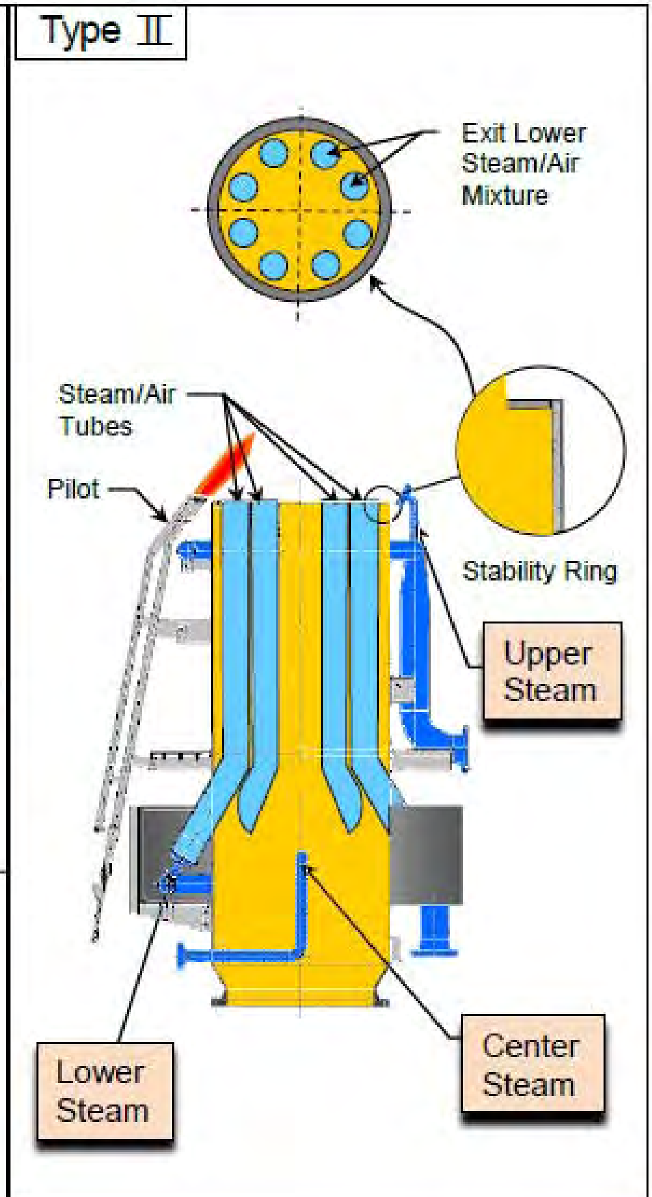
v. A quantification of the total flow and a calculation of the percent over the standard.

73. Emissions Data. In the semi-annual report that is required to be submitted by Paragraph 99 of Part VIII of the Consent Decree by August 15 of each year, BPP shall provide, for each Covered Flare and the LPG Flare, for the prior calendar year, the amount of emissions of the following compounds (in tons per year): VOCs, $SO_2$, $H_2S$, $CO_2$, methane, and ethane.

# Appendix FLR-1



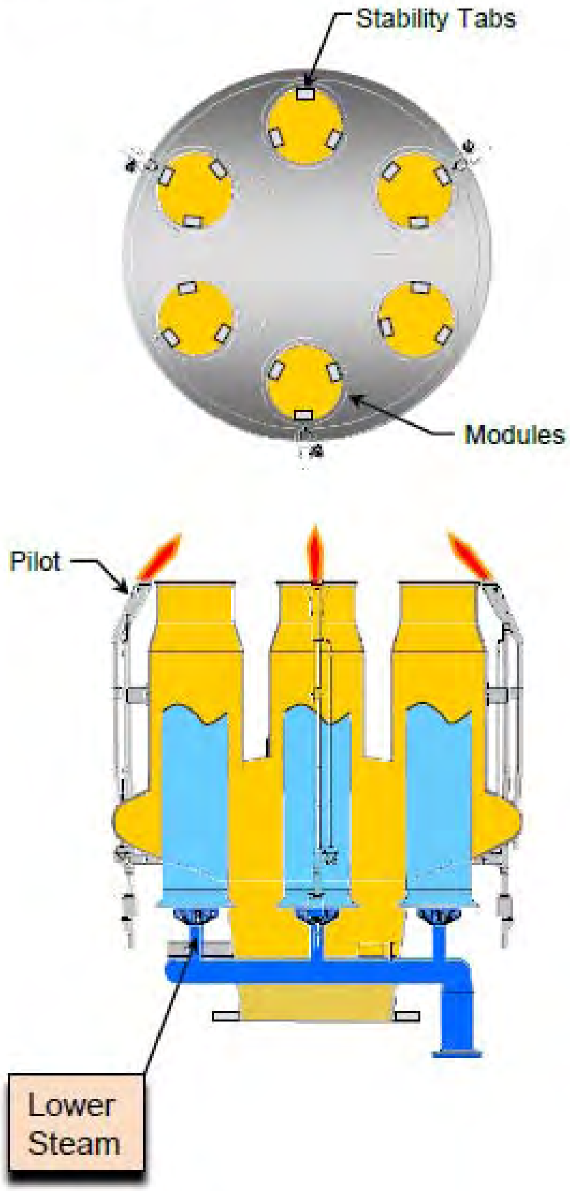




Key:

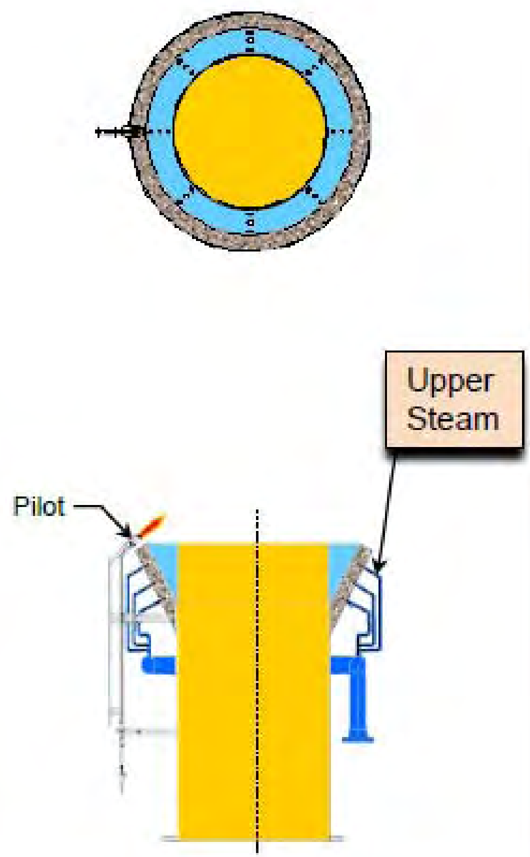
Yellow = Vent Gas
Red = Fire
Light Blue = Steam / Air
Dark Blue = Steam

# Appendix FLR-1

## Type III




## Type IV




Key:
Yellow = Vent Gas
Red = Fire
Light Blue = Steam / Air
Dark Blue = Steam

## APPENDIX FLR-2

## GENERAL EQUATIONS

***Equation 1:*** ***"Combustion Efficiency"*** **or** ***"CE"*****:**

$$CE = [CO_2]/([CO_2] + [CO] + [OC])$$

where:

$[CO_2]$ = Concentration in volume percent or ppm-meters of carbon dioxide in the combusted gas immediately above the Combustion Zone

$[CO]$ = Concentration in volume percent or ppm-meters of carbon monoxide in the combusted gas immediately above the Combustion Zone

$[OC]$ = Concentration in volume percent or ppm-meters of the sum of all organic carbon compounds in the combusted gas immediately above the Combustion Zone, counting each carbon molecule separately where the concentration of each individual compound is multiplied by the number of carbon atoms it contains before summing (*e.g.*, 0.1 volume percent ethane shall count as 0.2 percent OC because ethane has two carbon atoms)

For purposes of using the *CE* equation, the unit of measurement for $CO_2$, CO, and OC must be the same; that is, if "volume percent" is used for one compound, it must be used for all compounds. "Volume percent" cannot be used for one or more compounds and "ppm-meters" for the remainder.

***Equation 2: "Center Steam Mass Flow Rate" or "$\dot{m}_{s\text{-}cen}$":***

$$\dot{m}_{s\text{-}cen} = Q_{s\text{-}cen} \times (18/385.5)$$

where:

$Q_{s\text{-}cen}$ = Center Steam Volumetric Flow Rate

***Equation 3: "Total Steam Mass Flow Rate" or "$\dot{m}_s$":***

$$\dot{m}_s = Q_s \times (18/385.5)$$

where:

$Q_s$ Total Steam Volumetric Flow Rate

***Equation 4:*** ***"Vent Gas Mass Flow Rate"*** **or "$\dot{m}_{vg}$":**

$\dot{m}_{vg}$ = $Q_{vg}$ x ($MW_{vg}$/385.5)

where:

$Q_{vg}$ = Vent Gas Volumetric Flow Rate

$MW_{vg}$ = Molecular Weight, in pounds per pound-mole, of the Vent Gas, as measured by the Vent Gas Average Molecular Weight Analyzer system described in Paragraph 8 of this Consent Decree

(End of Appendix FLR-2)

# APPENDIX FLR-3

## CALCULATING $NHV_{cz\text{-}limit}$ AND $NHV_{cz}$ FOR STEAM-ASSISTED FLARES

All abbreviations, constants, and variables are defined in the Key on Pages FLR-3-6 and FLR-3-7 ("Key to the Abbreviations") of this Appendix.

### Steps in the Calculations

### Step 1: Determine the Lower Flammability Limit ("LFL") of Each Individual Vent Gas Compound

Take the LFL values of each individual Vent Gas compound from Table 1 in this Appendix.

### Step 2: Calculate the LFL of the vent gas mixture

The average lower flammability limit of the vent gas is calculated by Le Chatelier's equation shown below as Equation 1. This calculation uses the weighted average of the LFLs of the individual compounds weighted by their volume percent of the vent gas. All inerts, including nitrogen, are assumed to have an infinite lower flammability limit (e.g. $LFL_{N2} = \infty$).

$$LFL_{vg} = \frac{1}{\sum_{i=1}^{n}\left(\frac{x_i}{LFL_i}\right)} \qquad \textit{Equation 1}$$

### Step 3: Determine the Net Heating Value of the Vent Gas ($NHV_{vg}$)

**If a Gas Chromatograph is used:** The net heating value of the vent gas is calculated and reported from the GC data at the conclusion of each analytical cycle (~10-15 minutes). Equation 2 is used to calculate the vent gas net heating value from each individual compound net heating value. Individual compound volume fractions are measured directly by the GC. A company is not required to measure water in Vent Gas, but if it chooses to measure water, then it must include water in the calculation of the $NHV_{vg}$ and adjust the concentration of the compounds measured by the GC to a wet basis. Individual compound net heating values, including water, are listed in Table 1 of this Appendix.

$$NHV_{vg} = \sum_{i=1}^{n}(x_i \cdot NHV_i) \qquad \textit{Equation 2}$$

**If a Net Heating Value Analyzer/Calculator is used**: Use the measured value.

NOTE: Table 1 includes two alternative values for the Net Heating Value of hydrogen: the actual NHV of hydrogen (274 BTU/scf) and an "adjusted" NHV of hydrogen (1212 BTU/scf). Companies have the option of using either in calculating $NHV_{vg}$; however, whichever option is selected also must be used in calculating $NHV_{cz}$.

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**Step 4: Calculate the $NHV_{vg}$ at its LFL ($NHV_{vg\text{-}LFL}$)**

Using $LFL_{vg}$ from Equation 1 and $NHV_{vg}$ from Equation 2, the $NHV_{vg\text{-}LFL}$ is calculated by Equation 3.

$$NHV_{vg-LFL} = NHV_{vg} \cdot LFL_{vg} \qquad \textit{Equation 3}$$

**Step 5: Multiply $NHV_{vg\text{-}LFL}$ by the Combustion Efficiency Multipliers to calculate the *$NHV_{cz\text{-}limit}$***

The Net Heating Value of the Gases in the Combustion Zone ($NHV_{cz}$) of a Flare that is needed to ensure an acceptable Combustion Efficiency is determined by multiplying $NHV_{vg\text{-}LFL}$ by Combustion Efficiency Multipliers appropriate to the flare category and the volume percent of hydrogen in the Vent Gas as defined in Table 2.

The Net Heating Value of Combustion Zone Gas Limit is calculated as follows:

$$NHV_{cz-limit} = \left(A + B \cdot x_{propylene}\right) \cdot NHV_{vg-LFL} \qquad \textit{Equation 4}$$

**Step 6: Calculate the Net Heating Value of the Combustion Zone Gas ($NHV_{cz}$)**

The NHV in the combustion zone ($NHV_{cz}$) combines the NHVs of the Vent Gas, pilot gas, and steam and is calculated by Equation 5a (based on mass flow measurement) or 5b (based on volumetric flow measurement). These two equations are equivalent for combustion zone conditions, as shown in Addendum A to this Appendix. The NHV of steam is assumed to be zero. Vent Gas flow rate ($\dot{m}_{vg}$ *or* $Q_{vg}$) and steam flow rate ($\dot{m}_s$ *or* $Q_s$) are calculated from on-line flow meters. The pilot gas mass flow rate ($\dot{m}_{pg}$ *or* $Q_{pg}$ ) is constant for each flare and set by an orifice.

$$NHV_{cz} = \frac{\left(\frac{\dot{m}_{vg} \cdot NHV_{vg}}{MW_{vg}}\right) + \left(\frac{\dot{m}_{pg} \cdot NHV_{pg}}{MW_{pg}}\right)}{\left(\frac{\dot{m}_{vg}}{MW_{vg}}\right) + \left(\frac{\dot{m}_{pg}}{MW_{pg}}\right) + \left(\frac{\dot{m}_{s}}{MW_{H_2O}}\right) + \left(\frac{\dot{m}_{air}}{MW_{air}}\right)} \qquad \textit{Equation 5a}$$

**OR**

$$NHV_{cz} = \frac{\left(Q_{vg} *\ NHV_{vg}\right) + \left(Q_{pg} * NHV_{pg}\right)}{Q_{vg} + Q_{pg} + Q_s + Q_{air}} \qquad \textit{Equation 5b}$$

The values for $\dot{m}_s$, $\dot{m}_{air}$, $Q_s$, and $Q_{air}$ are determined as follows based on the type of flare:

**Steam-Assisted Flare without a Minimum Steam Reduction System ("MSRS")**

$\dot{m}_s \; or \; Q_s = measured \; value$

$\dot{m}_{air} \; or \; Q_{air} = 0$

**Steam-Assisted Flare with MSRS**

$\dot{m}_s \; or \; Q_s = measured \; value$

$\dot{m}_{air} \; or \; Q_{air} = result \; from \; Equation \; 13 \; in \; Step \; 6a$

**OR**

$\dot{m}_{air} \; or \; Q_{air} = 0$ *with vendor certification that the MSRS equipment installed on the flare is not capable (even at minimum vent gas flow) of inspirating more than twice the stoichiometric volume of air into the vent gas.*

The molecular weight of the vent gas ($MW_{vg}$) is calculated from the GC data using Equation 6. An on-line ultrasonic flow meter may also be used to calculate $MW_{vg}$. Individual compound molecular weights are listed in Table 1 of this Appendix.

$$MW_{vg} = \sum_{i=1}^{n} (x_i \cdot MW_i) \qquad \textbf{\textit{Equation 6}}$$

The NHV of the pilot gas ($NHV_{pg}$) and MW of the pilot gas ($MW_{pg}$) are calculated using Equations 7 and 8, respectively. These calculations are similar to the vent gas calculations, except the individual compound volume fractions are that of the pilot gas and not the vent gas. Individual compound volume fractions are measured by laboratory analysis of a pilot gas sample, or may be taken from the natural gas supplier's laboratory certificate of analysis.

$$NHV_{pg} = \sum_{i=1}^{n} (pg_i \cdot NHV_i) \qquad \textbf{\textit{Equation 7}}$$

$$MW_{pg} = \sum_{i=1}^{n} (pg_i \cdot MW_i) \qquad \textbf{\textit{Equation 8}}$$

**Step 6a:** Calculation of air mass flow rate for flares equipped with MSRS.

The complete combustion of an organic compound comprised of a combination of carbon and hydrogen atoms is shown in Equation 9:

$$C_xH_y + \left(x + \frac{y}{4}\right) O_2 \rightarrow xCO_2 + \left(\frac{y}{2}\right) H_2O \qquad \textbf{\textit{Equation 9}}$$

Note: *x* and *y* values for each compound are found in Table 1 of this Appendix.

Therefore, the stoichiometric oxygen molar flow rate (moles/hr) for any given combustible compound flow is defined by Equation 10a (mass basis) or Equation 10b (volumetric basis):

$$\dot{n}_{O2-stoich} = x_j \left(\frac{\dot{m}_{vg}}{MW_{vg}}\right)\left(x + \frac{y}{4}\right) \qquad \textbf{\textit{Equation 10a}}$$

$$OR$$

$$n_{O2-stoich} = x_j \left(\frac{Q_{vg}}{385.5}\right)\left(x + \frac{y}{4}\right) \qquad \textbf{\textit{Equation 10b}}$$

The stoichiometric oxygen mass flow rate for the vent gas (lb/hr) or stoichiometric oxygen volumetric flow rate for the vent gas (scfh) is given by Equation 11a (mass basis) or 11b (volumetric basis).

$$\dot{m}_{O2-stoich-vg} = MW_{O_2} * \sum_{j=1}^{n} \dot{n}_{O2-stoich_j} \qquad \textbf{\textit{Equation 11a}}$$

$$OR$$

$$Q_{O2-stoich-vg} = 385.5 * \sum_{j=1}^{n} \dot{n}_{O2-stoich_j} \qquad \textbf{\textit{Equation 11b}}$$

The stoichiometric air mass flow rate (lb/hr) or stoichiometric air volumetric flow rate (scfh) for the vent gas is given by Equation 12a (mass basis) or Equation 12b (volumetric basis).

$$\dot{m}_{air-stoich-vg} = \frac{MW_{air}}{0.21 \cdot MW_{O_2}} * \dot{m}_{O2-stoich-vg} \qquad \textbf{\textit{Equation 12a}}$$

$$OR$$

$$Q_{air-stoich-vg} = \frac{Q_{O2-stoich-vgvg}}{0.21} \qquad \textbf{\textit{Equation 12b}}$$

The air mass flow (lb/hour) or air volumetric flow (scfh) used in Equation 5a or 5b is given by subtracting two times the stoichiometric air from the total air provided by the MSRS. This is shown in Equation 13.

$$\dot{m}_{air} = \dot{m}_{air-MSRS} - (2 * \dot{m}_{air-stoich-vg}) \qquad \textbf{\textit{Equation 13a}}$$

$$OR$$

$$Q_{air} = Q_{air-MSRS} - (2 * Q_{air-stoich-vg}) \qquad \textbf{\textit{Equation 13b}}$$

The equation for $\dot{m}_{air-MSRS}$ or $Q_{air-MSRS}$ is specific to the MSRS installed and must be provided by the MSRS vendor. The factor of 2 used in Equation 13 is based on the best information available as of the Date of Lodging. If new information becomes available thereafter, the parties may modify that factor; any such modification does not constitute a material modification to the Consent Decree.

If $\dot{m}_{air} < 0$ then $\dot{m}_{air} = 0$
OR
If $Q_{air} < 0 \; then \; Q_{air} = 0$

**Step 7: Ensure that during flare operation, $NHV_{cz} \geq NHV_{cz\text{-}limit}$**

The flare must be operated to ensure that $NHV_{cz}$ is equal to or above $NHV_{cz\text{-}limit}$ to ensure an acceptable combustion efficiency. Equation 14 shows this relationship.

$$NHV_{cz} \geq NHV_{cz-limit} \qquad \textbf{\textit{Equation 14}}$$

**Key to the Abbreviations:**

$0.21 \quad mole\ fraction\ of\ oxygen\ in\ air (0.21\ lb\text{-}mol\ O_2/lb\text{-}mol\ air)$
$385.5 = conversion\ from\ pound\ moles\ to\ standard\ cubic\ feet\ (385.5\ scf/lb\text{-}mol)$
$A = overall\ combustion\ efficiency\ multiplier\ for\ NHV_{vg-LFL}\ (unitless)$
$B = propylene\ combustion\ efficiency\ multiplier\ for\ NHV_{vg-LFL}\ (unitless)$
$C_{vg} = concentration\ of\ VOC\ in\ the\ vent\ gas\ (vol\ \%)$
$i = individual\ numbered\ compound\ from\ column\ i\ in\ Table\ 1\ (unitless)$
$j = individual\ numbered\ compound\ from\ column\ j\ in\ Table\ 1\ (unitless)$
$k = individual\ gaseous\ component\ of\ the\ combustion\ zone\ (unitless)$
$LFL_i = lower\ flammability\ limit\ of\ individual\ compound\ (vol\ \%)$
$LFL_{vg} = lower\ flammability\ limit\ of\ vent\ gas\ (vol\ \%)$
$\dot{m}_{air} = mass\ flow\ rate\ of\ air\ (lb/hr)$
$\dot{m}_{air-MSRS} = total\ mass\ flow\ rate\ of\ air\ introduced\ by\ an\ MSRS\ (lb/hr)$
$\dot{m}_{air-stoich-vg} = stoichiometric\ air\ flow\ for\ the\ vent\ gas (lb/hr)$
$\dot{m}_k = mass\ flow\ rate\ of\ individual\ combustion\ zone\ gas\ component\ (lb/hr)$
$\dot{m}_{O2-stoich-vg} = stoichiometric\ oxygen\ mass\ flow\ for\ the\ vent\ gas\ (lb/hr)$
$\dot{m}_{pg} = mass\ flow\ rate\ of\ pilot\ gas\ (lb/hr)$
$\dot{m}_s = mass\ flow\ rate\ of\ total\ steam\ (lb/hr)$
$\dot{m}_{vg} = mass\ flow\ rate\ of\ vent\ gas\ (lb/hr)$
$\dot{n}_{O2-stoich} = stoichiometric\ oxygen\ mass\ flow\ for\ an\ individual\ compound\ (mol/hr)$
$MW_{H_2O} = molecular\ weight\ of\ water\ (18.02\ lb/lb\text{-}mol)$
$MW_i = molecular\ weight\ of\ individual\ compound\ (lb/lb\text{-}mol)$
$MW_k = molecular\ weight\ of\ individual\ combustion\ zone\ gas\ component (lb/lb\text{-}mol)$
$MW_{O_2} = molecular\ weight\ of\ oxygen\ (32.0\ lb/lb\text{-}mol)$
$MW_{air} = molecular\ weight\ of\ air\ (28.9\ lb/lb\text{-}mol)$
$MW_{pg} = molecular\ weight\ of\ pilot\ gas\ (lb/lb\text{-}mol)$
$MW_{vg} = molecular\ weight\ of\ vent\ gas\ (lb/lb\text{-}mol)$
$n = list\ of\ individual\ compounds\ from\ Table\ 1\ (unitless)$
$NHV_{cz} = net\ heating\ value\ of\ the\ combustion\ zone\ (BTU/scf)$
$NHV_i = net\ heating\ value\ of\ individual\ compound\ (BTU/scf)$
$NHV_{vg-LFL} = net\ heating\ value\ vent\ gas\ at\ lower\ flammability\ limit\ (BTU/scf)$
$NHV_{cz-limit} = limit\ net\ heating\ value\ of\ the\ combustion\ zone\ (BTU/scf)$
$NHV_{pg} = net\ heating\ value\ of\ pilot\ gas\ (BTU/scf)$
$NHV_{vg} = net\ heating\ value\ of\ vent\ gas\ (BTU/scf)$
$P_{cz} = pressure\ of\ combustion\ zone\ gas\ (psia)$
$P_{std} = ambent\ pressure\ at\ standard\ condtions\ (14.696\ psi)$
$pg_i = individual\ compound\ volume\ fraction\ in\ pilot\ gas\ (vol\ fraction)$
$Q_{air-MSRS} = total\ volumetric\ flow\ rate\ of\ air\ introduced\ by\ an\ MSRS\ (scfh)$
$Q_{air-stoich-vg} = stoichiometric\ air\ volumetric\ flow\ for\ the\ vent\ gas\ (scfh)$
$Q_k = individal\ vent\ gas\ component\ volumetric\ flow\ rate\ (scfh)$
$Q_{k,acf} = individal\ vent\ gas\ component\ volumetric\ flow\ rate\ (ft^3/hr)$
$Q_{O2-stoich-vg} = stoichiometric\ oxygen\ volumetric\ flow\ for\ the\ vent\ gas\ (scfh)$
$Q_{vg} = vent\ gas\ volumetric\ flow\ rate\ (scfh)$
$Q_{pg} = pilot\ gas\ volumetric\ flow\ rate\ (scfh)$
$Q_s = steam\ volumetric\ flow\ rate\ (scfh)$
$Q_{air} = air\ volumetric\ flow\ rate\ (scfh)$

$R = gas\ constant\ (10.73\ ft^3 \cdot psi/lb - mol \cdot R)$
$T_{cz} = absolute\ temperature\ of\ combustion\ zone\ gas\ (°R)$
$T_{std} = absolute\ temperature\ at\ standard\ conditions (528°R)$
$x = mole\ \ of\ carbon\ per\ mole\ of\ C_xH_y\ (mol/mol)$
$x_i = individual\ compound\ volume\ fraction\ in\ the\ vent\ gas\ (vol\ fraction)$
$x_j = individual\ combustible\ compound\ volume\ fraction\ in\ the\ vent\ gas\ (vol\ fraction)$
$x_{propylene} = volume\ fraction\ of\ propylene\ in\ the\ vent\ gas\ (vol\ fraction)$
$y = moles\ of\ hydrogen\ \ per\ mole\ of\ C_xH_y\ (mol/mol)$

**Table 1**
**Individual Compound Properties**

| $I^{(1)}$ | j | Compound | $NHV_i$ (Btu/scf) | $MW_i$ (lb/lbmol) | $LFL_i$ (vol fraction) | $C_x$ | $H_y$ |
|---|---|---|---|---|---|---|---|
| 1 | 1 | Hydrogen | 274 or 1212[(2)] | 2.02 | 0.040 | 0 | 2 |
| 2 | | Oxygen | 0 | 32.00 | ∞ | na | na |
| 3 | | Nitrogen | 0 | 28.01 | ∞ | na | na |
| 4 | | $CO_2$ | 0 | 44.01 | ∞ | na | na |
| 5 | | CO | 316 | 28.01 | 0.125 | na | na |
| 6 | 2 | Methane | 896 | 16.04 | 0.050 | 1 | 4 |
| 7 | 3 | Ethane | 1595 | 30.07 | 0.030 | 2 | 6 |
| 8 | 4 | Ethylene | 1477 | 28.05 | 0.027 | 2 | 4 |
| 9 | 5 | Acetylene | 1404 | 26.04 | 0.025 | 2 | 2 |
| 10 | 6 | Propane | 2281 | 44.10 | 0.021 | 3 | 8 |
| 11 | 7 | Propylene | 2150 | 42.08 | 0.024 | 3 | 6 |
| 12 | 8 | iso-Butane | 2957 | 58.12 | 0.018 | 4 | 10 |
| 13 | 9 | n-Butane | 2968 | 58.12 | 0.018 | 4 | 10 |
| 14 | 10 | iso-Butene, Butene-1, trans-Butene-2, cis-Butene-2 and 1,3 Butadiene combined | 2826 | 56.11 | 0.018 | 4 | 8 |
| 15 | 11 | Pentane+ ($C_5$+) | 3655 | 72.15 | 0.014 | 5 | 12 |
| 16 | 12 | Hydrogen Sulfide | 587 | 34.08 | 0.043 | 0 | 2 |
| 17 | | Water | 0 | 18.02 | ∞ | na | na |

[1] i=all compounds, j=organic compounds and hydrogen

[2] If using an $H_2$-adjusted $NHV_{vg}$ and $NHV_{cz}$, then use 1212 BTU/scf for hydrogen.

Note: Benzene and 1,3 butadiene are not required to be speciated by the Gas Chromatograph for this refinery settlement (*see* Appendix FLR-10) because benzene and 1,3 butadiene are present in the Vent Gas only in *de minimis* quantities. Because benzene and 1,3 butadiene speciation are not required, they are not listed in Table 1of this Appendix. The Vent Gas composition involved in other future settlements should be evaluated on a case-by-case basis to determine if benzene or 1,3 butadiene speciation should be required.

**Table 2**
**Combustion Efficiency Multipliers for Steam-Assisted Flares:**
**Variables Based on Minimum Steam Requirements**
**and VOC Concentration in the Vent Gas**

| Minimum Steam | VOC Vent Gas Concentration | A Multiplier | B Multiplier* | |
|---|---|---|---|---|
| | | | Condition A | Condition B |
| $\leq$ 1000 lb/hr | $\leq$ 20.0% | 6.45 | 4.0 | 0.0 |
| $\leq$ 1000 lb/hr | > 20.0% | 6.85 | 4.0 | 0.0 |
| > 1000 lb/hr | $\leq$ 20.0% | 7.1 | 4.0 | 0.0 |
| > 1000 lb/hr | > 20.0% | 7.4 | 4.0 | 0.0 |

*The B Multiplier used depends on the relationship of hydrogen and propylene in the vent gas as follows:
Condition A: $3 \leq H_2\% \leq 8$ and Propylene% $\geq H_2\%$ (all percents are volume or mole percents)
Condition B: Any condition not meeting the requirements for Condition A.

Note: The specifications for Condition A are based on the best information available as of the Date of Lodging. If new information becomes available thereafter, the parties may modify these conditions; any such modification does not constitute a material modification to the Consent Decree.

The "VOC Vent Gas Concentration" shall be calculated on an annual average basis as follows:

$$C_{vg} = \sum_{j=4}^{n} x_j * 100 \qquad \textbf{\textit{Equation 16}}$$

Note: The summation does not include methane or ethane.

**Addendum A to Appendix FLR-3**
**Verification of Equation 5A and Equation 5B Equivalency:**

In this Appendix, all gaseous flows (i.e, vent gas, steam, pilot gas, and air) may be measured on either a mass basis (lb/hr) or a volumetric basis (scfh). Depending on which measurement methodology is used, different versions of some equations must be used. These versions are designated with an "a" or "b" (e.g. Equation 5a or 5b). In all cases, these equations are equivalent. This Addendum demonstrates the equivalence of the two methods for calculating NHVcz.

Equation 5b uses volumetric flow rates for the calculation of $NHV_{cz}$:

$$NHV_{cz} = \frac{\left(Q_{vg} * NHV_{vg}\right) + \left(Q_{pg} * NHV_{pg}\right)}{Q_{vg} + Q_{pg} + Q_s + Q_{air}} \qquad \textbf{\textit{Equation 5b}}$$

The ideal gas law provides a method for determining volumetric flow rate of a specific gas, *k*, in the combustion zone at standard conditions:

$$Q_k = Q_{k,acf} * \frac{P_{cz}}{P_{std}} * \frac{T_{std}}{T_{cz}} \qquad \textbf{\textit{Equation A1}}$$

$$Q_{k,acf} = \frac{\dot{m}_k R T_{cz}}{MW_k P_{cz}} \qquad \textbf{\textit{Equation A2}}$$

$$Q_k = \frac{\dot{m}_k R T_{cz}}{MW_k P_{cz}} * \frac{P_{cz}}{P_{std}} * \frac{T_{std}}{T_{cz}} = \frac{\dot{m}_k R T_{std}}{MW_k P_{std}} \qquad \textbf{\textit{Equation A3}}$$

$$Q_k = \frac{\dot{m}_k * 10.73 * 528}{MW_k * 14.696} = 385.5 \frac{\dot{m}_k}{MW_k} \qquad \textbf{\textit{Equation A4}}$$

Substitution of this expression into Equation 5b gives $NHV_{cz}$ in terms of mass flow:

$$NHV_{cz} = \frac{\left(385.5 \frac{\dot{m}_{vg}}{MW_{vg}} * NHV_{vg}\right) + \left(385.5 \frac{\dot{m}_{pg}}{MW_{pg}} * NHV_{pg}\right)}{385.5 \frac{\dot{m}_{vg}}{MW_{vg}} + 385.5 \frac{\dot{m}_{pg}}{MW_{pg}} + 385.5 \frac{\dot{m}_s}{MW_{H_2O}} + 385.5 \frac{\dot{m}_{air}}{MW_{air}}} \qquad \textbf{\textit{Equation A5}}$$

Because the combustion zone is well-mixed, each gaseous component of the combustion zone is at the same temperature and pressure. Thus, the last expression reduces to Equation 5a:

$$NHV_{cz} = \frac{\left(\frac{\dot{m}_{vg} \cdot NHV_{vg}}{MW_{vg}}\right) + \left(\frac{\dot{m}_{pg} \cdot NHV_{pg}}{MW_{pg}}\right)}{\left(\frac{\dot{m}_{vg}}{MW_{vg}}\right) + \left(\frac{\dot{m}_{pg}}{MW_{pg}}\right) + \left(\frac{\dot{m}_{s}}{MW_{H_2O}}\right) + \left(\frac{\dot{m}_{air}}{MW_{air}}\right)}$$ ***Equation 5a***

Therefore demonstrating the equivalence of Equations 5a and 5b.

# APPENDIX FLR - 4

## POLICY ON EXCESS EMISSIONS DURING MALFUNCTIONS, STARTUP, AND SHUTDOWN

Introduction

This policy specifies when and in what manner state implementation plans (SIPs) may provide for defenses to violations caused by periods of excess emissions due to malfunctions,[1] startup, or shutdown. Generally, since SIPs must provide for attainment and maintenance of the national ambient air quality standards and the achievement of PSD increments, all periods of excess emissions must be considered violations. Accordingly, any provision that allows for an automatic exemption[2] for excess emissions is prohibited.

However, the imposition of a penalty for excess emissions during malfunctions caused by circumstances entirely beyond the control of the owner or operator may not be appropriate. States may, therefore, as an exercise of their inherent enforcement discretion, choose not to penalize a source that has produced excess emissions under such circumstances.

This policy provides an alternative approach to enforcement discretion for areas and pollutants where the respective contributions of individual sources to pollutant concentrations in ambient air are such that no single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, as is often the case for sulfur dioxide and lead,[3] EPA believes approaches other than enforcement discretion are not appropriate. In such cases, any excess emissions may have a significant chance of causing an exceedance or violation of the applicable standard or PSD increment.

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[1]The term excess emission means an air emission level which exceeds any applicable emission limitation. Malfunction means a sudden and unavoidable breakdown of process or control equipment.

[2]The term automatic exemption means a generally applicable provision in a SIP that would provide that if certain conditions existed during a period of excess emissions, then those exceedances would not be considered violations.

[3]This policy also does not apply for purposes of PM2.5 NAAQS. In American Trucking Association v. EPA, 175 F. 3d 1027 (D.C. Circ., 1999), the court remanded the PM2.5 NAAQS to the EPA. The Agency has not determined whether this policy is appropriate for PM2.5 NAAQS.

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Except where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, states may include in their SIPs affirmative defenses[4] for excess emissions, as long as the SIP establishes limitations consistent with those set out below. If approved into a SIP, an affirmative defense would be available to sources in an enforcement action seeking penalties brought by the state, EPA, or citizens. However, a determination by the state not to take an enforcement action would not bar EPA or citizen action.[5]

In addition, in certain limited circumstances, it may be appropriate for the State to build into a source-specific or source-category-specific emission standard a provision stating that the otherwise applicable emission limitations do not apply during narrowly defined startup and shutdown periods.

I. AUTOMATIC EXEMPTIONS AND ENFORCEMENT DISCRETION

If a SIP contains a provision addressing excess emissions, it cannot be the type that provides for automatic exemptions. Automatic exemptions might aggravate ambient air quality by excusing excess emissions that cause or contribute to a violation of an ambient air quality standard. Additional grounds for disapproving a SIP that includes the automatic exemption approach are discussed in more detail at 42 Fed. Reg. 58171 (November 8, 1977) and 42 Fed. Reg. 21372 (April 27, 1977). As a result, EPA will not approve any SIP revisions that provide automatic exemptions for periods of excess emissions.

The best assurance that excess emissions will not interfere with NAAQS attainment, maintenance, or increments is to address excess emissions through enforcement discretion. This policy provides alternative means for addressing excess emissions of criteria pollutants. However, this policy does not apply where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Moreover,

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[4]The term affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

[5]Because all periods of excess emissions are violations and because affirmative defense provisions may not apply in actions for injunctive relief, under no circumstances would EPA consider periods of excess emissions, even if covered by an affirmative defense, to be "federally permitted releases" under EPCRA or CERCLA.

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nothing in this guidance should be construed as requiring States to include affirmative defense provisions in their SIPs.

## II. AFFIRMATIVE DEFENSES FOR MALFUNCTIONS

The EPA can approve a SIP revision that creates an affirmative defense to claims for penalties in enforcement actions regarding excess emissions caused by malfunctions as long as the defense does not apply to SIP provisions that derive from federally promulgated performance standards or emission limits, such as new source performance standards (NSPS) and national emissions standards for hazardous air pollutants (NESHAPS).[6] In addition, affirmative defenses are not appropriate for areas and pollutants where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Furthermore, affirmative defenses to claims for injunctive relief are not allowed. To be approved, an affirmative defense provision must provide that the defendant has the burden of proof of demonstrating that:

1. The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator;

2. The excess emissions (a) did not stem from any activity or event that could have been foreseen and avoided, or planned for, and (b) could not have been avoided by better operation and maintenance practices;

3. To the maximum extent practicable the air pollution control equipment or processes were maintained and operated in a manner consistent with good practice for minimizing emissions;

4. Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded. Off-shift labor and overtime must have been utilized, to the extent practicable, to ensure that such repairs were made as expeditiously as practicable;

5. The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

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[6] To the extent a State includes NSPS or NESHAPS in its SIP, the standards should not deviate from those that were federally promulgated. Because EPA set these standards taking into account technological limitations, additional exemptions would be inappropriate.

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6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence;

9. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

10. The owner or operator properly and promptly notified the appropriate regulatory authority.

The EPA interprets these criteria narrowly. Only those malfunctions that are sudden, unavoidable, and unpredictable in nature qualify for the defense. For example, a single instance of a burst pipe that meets the above criteria may qualify under an affirmative defense. The defense would not be available, however, if the facility had a history of similar failures because of improper design, improper maintenance, or poor operating practices. Furthermore, a source must have taken all available measures to compensate for and resolve the malfunction. If a facility has a baghouse fire that leads to excess emissions, the affirmative defense would be appropriate only for the period of time necessary to modify or curtail operations to come into compliance. The fire should not be used to excuse excess emissions generated during an extended period of time while the operator orders and installs new bags, and relevant SIP language must limit applicability of the affirmative defense accordingly.

III. EXCESS EMISSIONS DURING STARTUP AND SHUTDOWN

In general, startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

A. SOURCE CATEGORY SPECIFIC RULES FOR STARTUP AND SHUTDOWN

For some source categories, given the types of control technologies available, there may exist short periods of emissions during startup and shutdown when, despite best efforts regarding planning, design, and operating procedures, the

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otherwise applicable emission limitation cannot be met. Accordingly, except in the case where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, it may be appropriate, in consultation with EPA, to create narrowly-tailored SIP revisions that take these technological limitations into account and state that the otherwise applicable emissions limitations do not apply during narrowly defined startup and shutdown periods. To be approved, these revisions should meet the following requirements:

1. The revision must be limited to specific, narrowly-defined source categories using specific control strategies (e.g., cogeneration facilities burning natural gas and using selective catalytic reduction);

2. Use of the control strategy for this source category must be technically infeasible during startup or shutdown periods;

3. The frequency and duration of operation in startup or shutdown mode must be minimized to the maximum extent practicable;

4. As part of its justification of the SIP revision, the state should analyze the potential worst-case emissions that could occur during startup and shutdown;

5. All possible steps must be taken to minimize the impact of emissions during startup and shutdown on ambient air quality;

6. At all times, the facility must be operated in a manner consistent with good practice for minimizing emissions, and the source must have used best efforts regarding planning, design, and operating procedures to meet the otherwise applicable emission limitation; and

7. The owner or operator's actions during startup and shutdown periods must be documented by properly signed, contemporaneous operating logs, or other relevant evidence.

## B. GENERAL AFFIRMATIVE DEFENSE PROVISIONS RELATING TO STARTUP AND SHUTDOWN

In addition to the approach outlined in Section II(A) above, States may address the problem of excess emissions occurring during startup and shutdown periods through an enforcement discretion approach. Further, except in the case where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, States may also adopt for their SIPs an affirmative defense approach. Using this

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approach, all periods of excess emissions arising during startup and shutdown must be treated as violations, and the affirmative defense provision must not be available for claims for injunctive relief. Furthermore, to be approved, such a provision must provide that the defendant has the burden of proof of demonstrating that:

1. The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

2. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

3. If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

4. At all times, the facility was operated in a manner consistent with good practice for minimizing emissions;

5. The frequency and duration of operation in startup or shutdown mode was minimized to the maximum extent practicable;

6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and

9. The owner or operator properly and promptly notified the appropriate regulatory authority.

If excess emissions occur during routine startup or shutdown periods due to a malfunction, then those instances should be treated as other malfunctions that are subject to the malfunction provisions of this policy. (Reference Part I above).

# APPENDIX FLR-5

## CALCULATING MOMENTUM FLUX RATIO

Momentum Flux Ratio (MFR) is the relationship between the density ($\rho$) and velocity ($v$) of the Vent Gas plus Center Steam to the density and velocity of the wind. It is defined in Equation 1.

$$MFR = \frac{\rho_{vg+s,cent} \cdot {v_{vg+s,cent}}^2}{\rho_{air} \cdot {v_{air}}^2} \qquad \text{Equation 1}$$

The numerator of the fraction is the "momentum flux" of the Vent Gas plus Center Steam and the denominator is the "momentum flux" of the air (wind). As the velocity of the wind increases, the MFR will decline for a given Vent Gas composition and flow rate.

Calculations for the density ($\rho$) components and velocity ($v$) components are discussed separately below.

**Calculating Density**

The general formula to calculate the density of each component ($\rho_i$) – Ambient Air, Vent Gas, and Center Steam -- is shown in Equation 2.

$$\rho_i = \frac{MW_i \cdot P}{R \cdot T_{abs}} = \frac{MW_i \cdot 14.73}{10.73 \cdot (460 + T_i)} = \frac{1.373 \cdot MW_i}{460 + T_i} \qquad \text{Equation 2}$$

From the final form of Equation 2, the density of Ambient Air ($\rho_{air}$), Vent Gas ($\rho_{vg}$), and Center Steam ($\rho_{s,cent}$) can be calculated, shown in Equations 3, 4, and 5. The temperature of Center Steam and Ambient Air is measured. The temperature of Ambient Air and Vent Gas is assumed to be equal.

$$\rho_{air} = \frac{1.373 \cdot MW_{air}}{460 + T_{air}} \qquad \text{Equation 3}$$

$$\rho_{vg} = \frac{1.373 \cdot MW_{vg}}{460 + T_{air}} \qquad \text{Equation 4}$$

$$\rho_{s,cent} = \frac{1.373 \cdot MW_{H_2O}}{460 + T_{s,cent}} \qquad \text{Equation 5}$$

The density of the Vent Gas plus Center Steam ($\rho_{vg+c,cent}$) is calculated by combining the mass flow rates of the Vent Gas and Center Steam and dividing by the combined volumetric flow rates of the Vent Gas and Center Steam. This is shown in Equation 6.

$$\rho_{vg+s,cen} = \frac{m_{vg} + m_{s,cent}}{Q_{vg} + Q_{s,cent}} = \frac{m_{vg} + m_{s,cent}}{\frac{m_{vg}}{\rho_{vg}} + \frac{m_{s,cent}}{\rho_{s,cent}}} \qquad \text{Equation 6}$$

## Calculating Velocity

The velocity of the Vent Gas plus Center Steam ($v_{vg+s,cent}$) is calculated by Equation 7.

$$v_{vg+s,cent} = \frac{Q_{vg} + Q_{s,cent}}{A_{tip-unob}} = \frac{\frac{m_{vg}}{\rho_{vg}} + \frac{m_{s,cent}}{\rho_{s,cent}}}{\mathrm{A}_{tip-unob}} \qquad \text{Equation 7}$$

The wind velocity is measured directly.

### Constants:

$$MW_{air} = molecular\ weight\ of\ air\ \left(28.96\frac{lb}{lbmol}\right)$$
$$MW_{H_2O} = molecular\ weight\ of\ water\ \left(18.02\frac{lb}{lbmol}\right)$$
$$P = absolute\ ambient\ pressure\ (14.73\ psia)$$
$$R = gas\ constant\ \left(10.73\frac{psi \cdot ft^3}{lbmol \cdot {}^\circ R}\right)$$

### Measured variables:

$$MW_{vg} = molecular\ weight\ of\ Vent\ Gas\ \left(\frac{lb}{lbmol}\right)$$
$$\dot{m}_{s,cent} = mass\ flow\ rate\ of\ Center\ Steam\ \left(\frac{lb}{hr}\right)$$
$$\dot{m}_{vg} = mass\ flow\ rate\ of\ Vent\ Gas\ \left(\frac{lb}{hr}\right)$$
$$T_{air} = temperature\ of\ Ambient\ Air\ ({}^\circ\mathrm{F})$$
$$T_{s,cent} = temperature\ of\ Center\ Steam\ ({}^\circ\mathrm{F})$$
$$v_{air} = velocity\ of\ wind\ \left(\frac{ft}{hr}\right)$$

## Calculated variables:

$A_{tip-unob} = unobstructed\ cross - sectional\ area\ of\ flare\ tip\ (ft^2)$

$MFR = momentum\ flux\ ratio\ (unitless)$

$MW_i = molecular\ weight\ of\ component\ i\left(\frac{lb}{lbmol}\right)$

$\rho_{air} = density\ of\ air\ \left(\frac{lb}{ft^3}\right)$

$\rho_{vg} = density\ of\ Vent\ Gas\ \left(\frac{lb}{ft^3}\right)$

$\rho_{s,cent} = density\ of\ Center\ Steam\ \left(\frac{lb}{ft^3}\right)$

$\rho_i = density\ of\ component\ i\ \left(\frac{lb}{ft^3}\right)$

$Q_{s,cent} = volumetric\ flow\ rate\ of\ Center\ Steam\ \left(\frac{ft^3}{hr}\right)$

$Q_{vg} = volumetric\ flow\ rate\ of\ Vent\ Gas\ \left(\frac{ft^3}{hr}\right)$

$T_{abs} = absolute\ temperature\ (°R)$

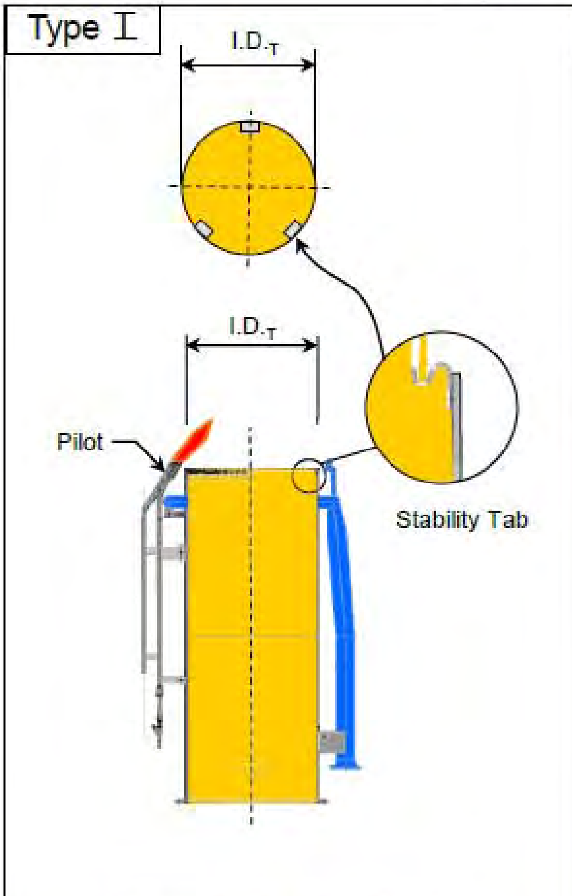
$T_i = temperature\ of\ component\ i\ \ (°F)$

$v_{vg} = velocity\ of\ Vent\ Gas\ \left(\frac{ft}{hr}\right)$

$v_{s,cent} = velocity\ of\ Center\ Steam\ \left(\frac{ft}{hr}\right)$

# Appendix FLR-6

## Type I




$A_{tip\text{-}unob} = \pi(I.D._T)^2/4 - (X_T * A_{ST})$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter Flare Tip

$X_T$ = Number of Stability Tabs

$A_{ST}$ = Area of a Stability Tab

Example: $I.D._T$ = 41.5 inches

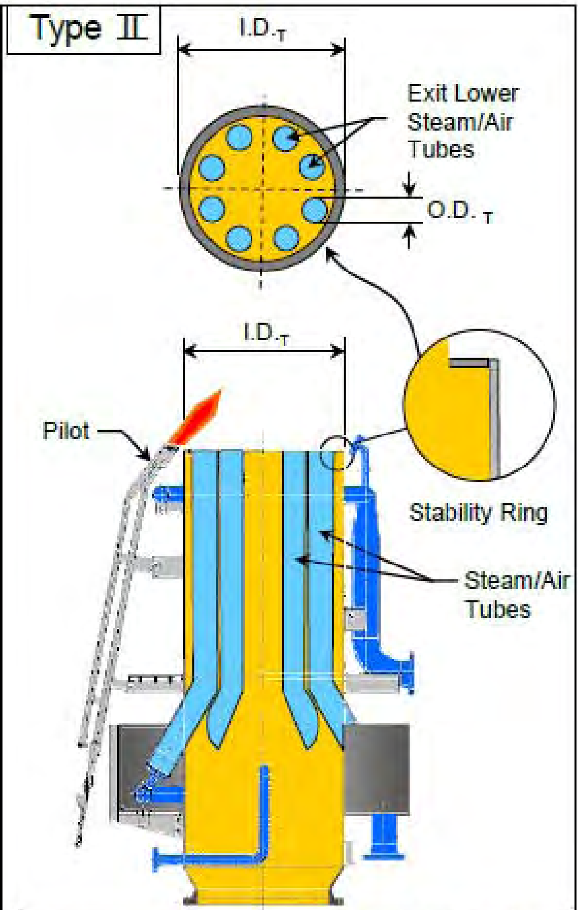
$X_T$ = 3

$A_{ST}$ = 3 Sq. inches

$A_{tip\text{-}unob} = \pi(41.5)^2/4 - (3 * 3)$

$A_{tip\text{-}unob}$ = 1344 Sq. inches

## Type II




$A_{tip\text{-}unob} = \pi(I.D._T)^2/4 - A_{ST} - N_T * \pi * (O.D._T)^2/4$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter Flare Tip

$A_{ST}$ = Area of Stability Ring

$O.D._T$ = Outside Diameter of Steam/Air Tubes

$N_T$ = Number of Steam/Air Tubes

Example: $I.D._T$ = 47.5 inches

$A_{ST}$ = 100 Sq. inches

$O.D._T$ = 6.5 inches

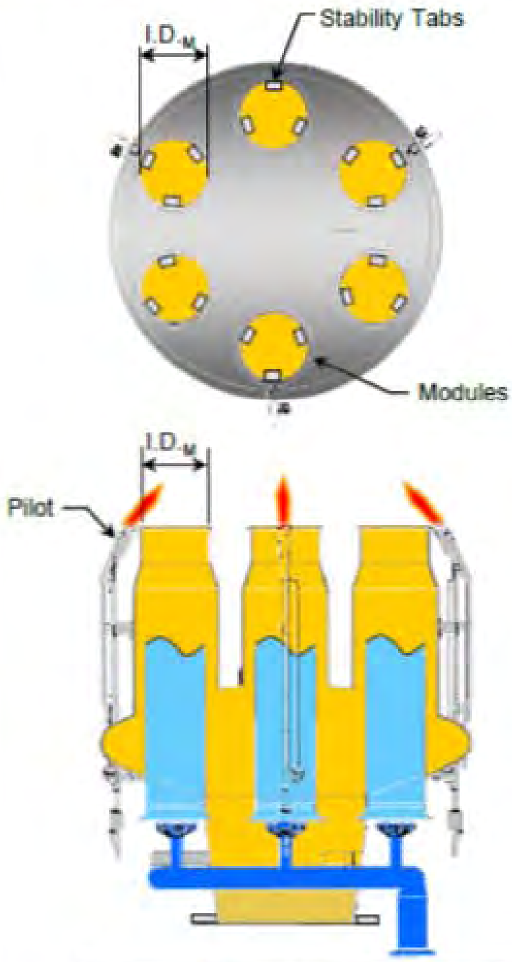
$N_T$ = 8

$A_{tip\text{-}unob} = \pi(47.5)^2/4 - 100 - 8 * \pi * (6.5)^2/4$

$A_{tip\text{-}unob}$ = 1322 Sq. inches

# Appendix FLR-6

## Type III




$A_{tip\text{-}unob} = N_M * (\pi*(I.D._{-M})^2/4 - X_T * A_{ST})$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._{-M}$ = Inside Diameter of One Tip Module

$N_M$ = Number of Modules

$X_T$ = Number of Stability Tabs per Module

$A_{ST}$ = Area of a Stability Tab

Example: $I.D._{-M}$ = 17 inches

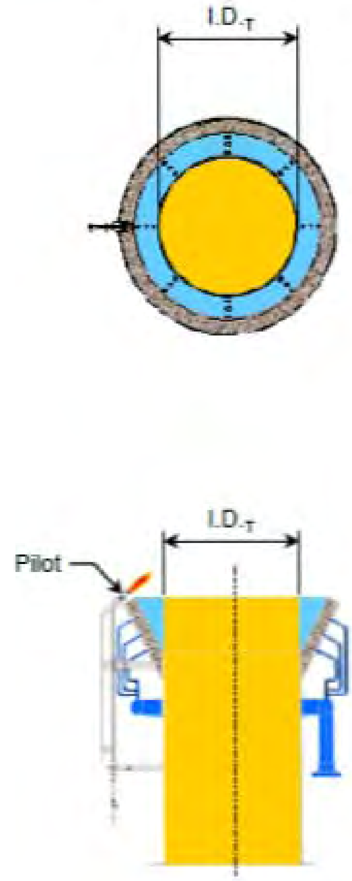
$N_M = 6$ $\quad$ $X_T = 3$

$A_{ST}$ = 3 Sq. inches

$A_{tip\text{-}unob} = 6 * (\pi*(17)^2/4 - 3 * 3)$

$A_{tip\text{-}unob}$ = 1308 Sq. inches

## Type IV




$A_{tip\text{-}unob} = \pi\,(I.D._{-T})^2/4$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

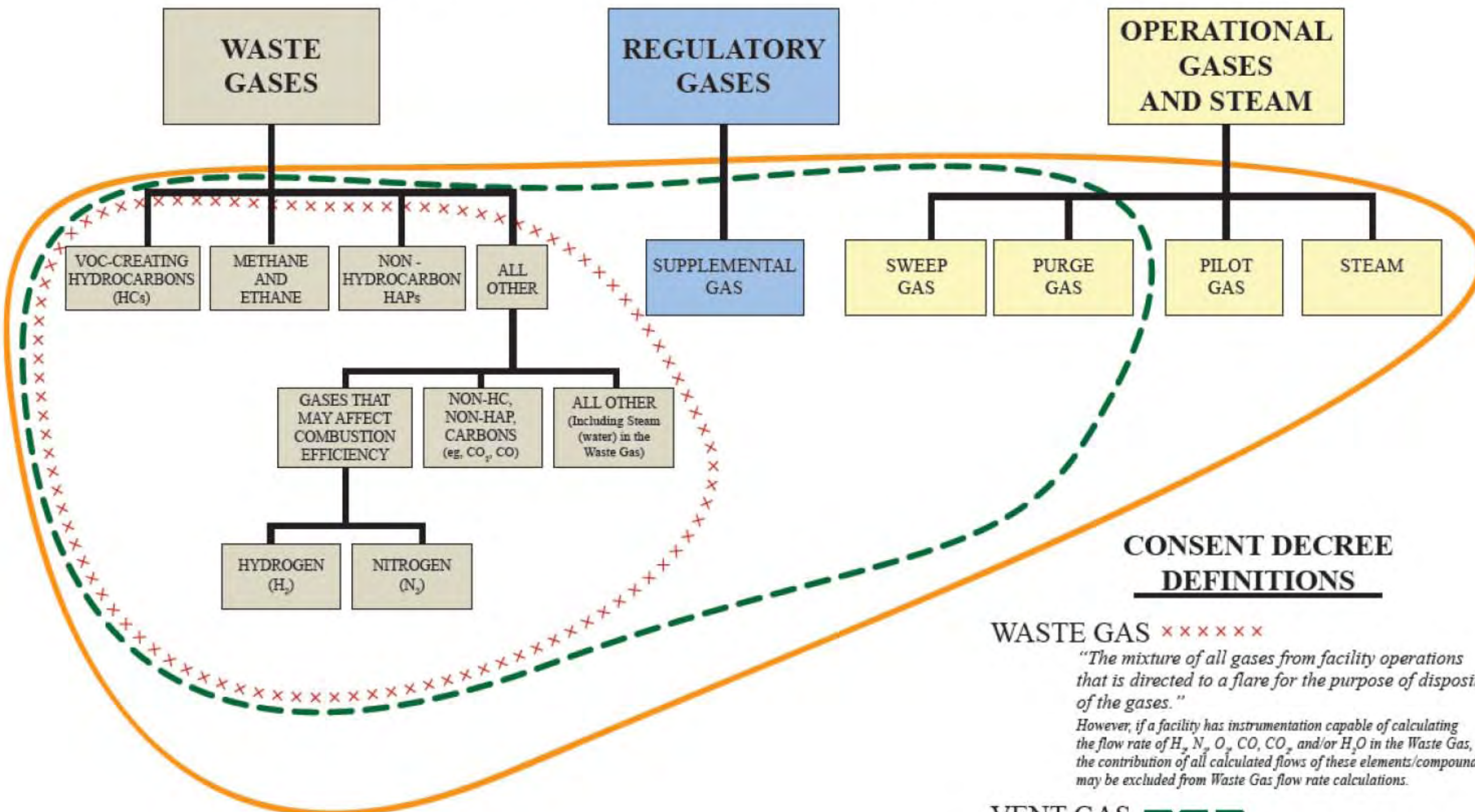
$I.D._{-T}$ = Inside Diameter of Flare Tip

Example: $I.D._{-T}$ = 41.5 inches

$A_{tip\text{-}unob} = \pi\,(41.5)^2/4$

$A_{tip\text{-}unob}$ = 1353 Sq. inches

# DEPICTION OF GASES ASSOCIATED WITH STEAM-ASSISTED FLARES




## CONSENT DECREE DEFINITIONS

WASTE GAS × × × × × ×

*"The mixture of all gases from facility operations that is directed to a flare for the purpose of disposing of the gases."*

*However, if a facility has instrumentation capable of calculating the flow rate of $H_2$, $N_2$, $O_2$, CO, $CO_2$, and/or $H_2O$ in the Waste Gas, the contribution of all calculated flows of these elements/compounds may be excluded from Waste Gas flow rate calculations.*

VENT GAS — — —

*"The mixture of all gases found prior to the flare tip. This includes all Waste Gas, Supplemental Gas, Sweep Gas, and Purge Gas."*

COMBUSTION ZONE GAS ———

*"The mixture of all gases and steam found just after the flare tip. This includes all Vent Gas, Pilot Gas, and Total Steam."*

**APPENDIX FLR-7**

**Appendix FLR-8**

**Large, High Pressure Hydrocarbon Relief Valves**

| Relief Valve Description | Inlet / Outlet Size | Pressure, psig |
|---|---|---|
| Ultrafiner Feed/Effluent Exchanger B - Cold Outlet | 4X6 | 797 |
| Ultrafiner Feed/Effluent Exchanger H - Cold Outlet | 4X6 | 797 |
| Ultrafiner Reactor - A | 4X6 | 440 |
| Ultrafiner Reactor - B | 4X6 | 440 |
| Ultrafiner Effluent H2O Cooler - Hot Inlet | 4X6 | 399 |
| Ultrafiner High Pressure Separator | 4X6 | 399 |
| 4UF Stripper Feed/Hot Oil Exchanger - Cold Side | 4X6 | 321 |
| CFHU High Pressure Separator RV1 | 3X6 | 1,285 |
| CFHU High Pressure Separator RV2 | 3X6 | 1,285 |
| CFHU High Pressure Separator RV3 | 3X6 | 1,285 |
| CFHU High Pressure Separator RV4 | 3X6 | 1,285 |
| CFHU High Pressure Separator RV5 | 3X6 | 1,285 |
| Cat Feed Unit Reactor A RV2 | 3X4 | 1,391 |
| Cat Feed Unit Reactor B RV2 | 3X4 | 1,379 |
| Cat Feed Unit Reactor A RV1 | 3X4 | 1,391 |
| CFHU Reactor Effluent Vapor Water Condenser | 3X4 | 1,285 |
| Cat Feed Unit Reactor B RV1 | 3X4 | 1,379 |
| DDU Reactor 1 | 4X6 | 689 |
| DDU Reactor 2 | 4X6 | 715 |
| DDU High Temperature Separator | 4X6 | 600 |
| DHT Cold High Pressure Separator RV6 | 3X4 | 867 |
| DHT Cold High Pressure Separator RV7 | 3X4 | 867 |
| PCU Feed Gas Line | 4X6 | 300 |
| PCU Feed Surge Drum | 3X4 | 300 |
| PCU Tower 101 Reboiler - Hot Inlet | 3X4 | 300 |
| PCU Deethanizer | 3X4 | 580 |
| Alky Reactor Effluent / Debutanizer Bottoms Exchanger - shell side | 4X6 | 362 |
| Isom Absorber Feed Mix Drum RV1 | 4X6 | 300 |
| Isom Absorber Feed Mix Drum RV2 | 4X6 | 300 |
| Isom Heater Absorber Radiant Coil | 3X4 | 300 |
| CRU Reactor | 6X8 | 357 |
| CRU Feed/Reactor Effluent Exchangers B/C/G - shell side | 3X4 | 412 |
| CRU Feed/Reactor Effluent Exchangers D/E/F - shell side | 3X4 | 412 |
| VRU 200 Wild Gasoline Coalescer | 4X6 | 217 |
| HU High Temperature Shift Reactor Inlet | 6X8 | 332 |
| HU Cold Condensate Drum | 4X6 | 293 |

FLR-9

**OUTLINE OF REQUIREMENTS FOR THE FLARE DATA AND INITIAL MONITORING SYSTEMS REPORT**

1. Facility-Wide

1.1 Facility plot plan showing the location of each flare in relation to the general plant layout

2. General Description of Flare

2.1 Ground or elevated
2.2 Type of assist system
2.3 Simple or integrated (*e.g.*, sequential, staged)
2.4 Date first installed
2.5 History of any physical changes to the Flare
2.6 Whether the Flare is a Temporary-Use Flare, and if so, the duration and time periods of use
2.7 Flare Gas Recovery System ("FGRS"), if any, and date first installed

3. Flare Components: Complete description of each major component of the Flare, except the Flare Gas Recovery System (*see* Part 5), including but not limited to:

3.1 Flare stack (for elevated flares)
3.2 Flare tip
3.1.2.1 Date installed
3.1.2.2 Manufacturer
3.1.2.3 Tip Size
3.1.2.4 Tip Drawing
3.3 Knockout or surge drum(s) or pot(s), including dimensions and design capacities
3.4 Water seal(s), including dimensions and design parameters
3.5 Flare header(s)
3.6 Sweep Gas system
3.7 Purge gas system
3.8 Pilot gas system
3.9 Supplemental gas system
3.10 Assist system
3.11 Ignition system

4. Simplified process diagram(s) showing the configuration of the components listed in Paragraph 3

5. Existing Flare Gas Recovery System ("FGRS")

5.1 Complete description of each major component, including but not limited to:

5.1.1 Compressor(s), including design capacities
5.1.2 Water seal(s), rupture disk, or similar device to divert the flow

5.2 Maximum actual past flow on an scfm basis and the annual average flow in scfm for the five years preceding Date of Lodging

5.3 Simplified schematic showing the FRGS

5.4 Process Flow Diagram that adds the FGRS to the PDF(s) in Part 4

6. Flare Design Parameters

6.1 Maximum Vent Gas Flow Rate and/or Mass Rate
6.2 Maximum Sweep Gas Flow Rate and/or Mass Rate
6.3 Maximum Purge Gas Flow and/or Mass Rate, if applicable
6.4 Maximum Pilot Gas Flow and/or Mass Rate
6.5 Maximum Supplemental Gas Flow Rate and/or Mass Rate
6.6 If steam-assisted, Minimum Total Steam Rate, including all available information on how that Rate was derived

7. Gases Venting to Flare

7.1. Sweep Gas
7.1.1 Type of gas used
7.1.2 Actual set operating flow rate (in scfm)
7.1.3 Average lower heating value expected for each type of gas used

7.2 Purge Gas, if applicable
7.2.1 Type of gas used
7.2.2 Actual set operating flow rate (in scfm)
7.2.3 Average lower heating value expected for each type of gas used

7.3 Pilot Gas
7.3.1 Type of gas used
7.3.2 Actual set operating flow rate (in scfm)
7.3.3 Average lower heating value expected for each type of gas used

7.4 Supplemental Gas
7.4.1 Type of gas used
7.4.2 Average lower heating value expected for each type of gas used

7.5 Steam (if applicable)
7.5.1 Drawing showing points of introduction of Lower, Center, Upper, and any other steam

7.6 Simplified flow diagram that depicts the points of introduction of all gases, including Waste Gases, at the Flare (in this diagram, the detailed drawings of 7.5.1 may be simplified; in addition, detailed Waste Gas mapping is not required; a simple identification of the header(s) that carries(y) the Waste Gas to the Flare and show(s) its(their) location in relation to the location of the introduction of the other gases is all that is required)

8. Existing Monitoring Systems

8.1 A brief narrative description, including manufacturer and date of installation, of all existing monitoring systems, including but not limited to:

8.1.1 Waste Gas and/or Vent Gas flow monitoring
8.1.2 Waste Gas and/or Vent Gas heat content analyzer
81.3 Sweep Gas flow monitoring
8.1.4 Purge Gas flow monitoring
8.1.5 Supplemental Gas flow monitoring
8.1.6 Steam flow monitoring
8.1.7 Waste Gas or Vent Gas molecular weight analyzer
8.1.8 Gas Chromatograph
8.1.9 Sulfur analyzer(s)
8.1.10 Video camera
8.1.11 Thermocouple

8.2 Drawing(s) showing locations of all existing monitoring systems

9. Monitoring Equipment Installed to Comply with Consent Decree

10. Narrative Description of the Monitoring Methods and Calculations that will be used to comply with the $NHV_{CZ}$, S/VG, and Prohibition on Discontinuous Wake Dominated Flow or MFR Requirements in the Consent Decree

11. Identification of calibration gases to be used to comply with Appendix FLR-11

[End of FLR-9]

# APPENDIX FLR-10

## LIST OF COMPOUNDS A GAS CHROMATOGRAPH MUST BE CAPABLE OF SPECIATING

The Gas Chromatograph must be capable of speciating the Waste Gas into the following:

1. Hydrogen
2. Oxygen
3. Nitrogen
4. Carbon Dioxide
5. Carbon Monoxide
6. Methane
7. Ethane
8. Ethene (aka: Ethylene)
9. Acetylene
10. Propane
11. Propene (aka: Propylene)
12. 2-Methylpropane (aka: iso-Butane)
13. Butane (aka: n-Butane)
14. But-1-ene (aka: butene, alpha-butylene), 2-methylpropene (aka: iso-butylene, iso-butene), trans-Butene-2, cis-Butene-2 and 1,3 Butadiene combined into a single measurement
15. Pentane plus (aka: $C_5$ plus) (*i.e.*, all HCs with five Cs or more)
16. Hydrogen Sulfide
17. Water

Outputs from the Gas Chromatograph shall be on a mole percent basis except for Hydrogen Sulfide which will be on a parts per million basis.

Benzene and 1,3 butadiene are not required to be speciated by the Gas Chromatograph for this refinery settlement because benzene and 1,3 butadiene are present in the Vent Gas only in *de minimis* quantities. The Vent Gas composition involved in other future settlements should be evaluated on a case-by-case basis to determine if benzene or 1,3 butadiene speciation should be required.

(End of Appendix FLR-10)

APPENDIX FLR-11

EQUIPMENT AND INSTRUMENTATION TECHICAL SPECIFICATIONS
AND QUALITY ASSURANCE/QUALITY CONTROL REQUIREMENTS

## I. WASTE GAS FLOW METER

a. Velocity Range: 0.1–250 ft/sec

b. Repeatability: ± 10% of reading over the velocity range 0.1 ft/s to 1.0 ft/s
± 1% of reading over the velocity range > 1.0 ft/s to 250 ft/s

c. Design Accuracy: ± 5% initially to 40%, 60%, and 90% of monitor full scale as certified by the manufacturer

d. Operational Accuracy: ± 20% of reading over the velocity range of 0.1–1 ft/s and ± 5% of reading over the velocity range of 1–250 ft/s

e. Installation: Applicable AGA, ANSI, API, or equivalent standard

f. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F

g. QA/QC: Annual calibration shall be conducted beginning with the schedule given in Paragraph 6 of the flaring section.

h. Pressure and Temperature Sensors: *See* Part IV below.

## II. WASTE GAS AVERAGE MOLECULAR WEIGHT ANALYZER (may be part of the Waste Gas Flow Meter)

a. Molecular Weight Range and Accuracy: 2 to 120 gr/grmol, ± 2%

## III. STEAM FLOW METER

a. Repeatability: ± 1% of reading over the range of the instrument

b. Accuracy: +/- 1% from 100% to 15% of span
+/- 2% from 15% to 6% of span
+/- 3% from 6% to 4% of span

c. Installation: Applicable AGA, ANSI, API, or equivalent standard

d. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F

e. QA/QC: Annual calibration shall be conducted.

f. Pressure and Temperature Sensors: *See* Part IV below.

## IV. WASTE GAS AND STEAM FLOW METERS: PRESSURE AND TEMPERATURE SENSORS

Beginning with the schedule given in Paragraph 6 of the flaring section,

a. Temperature monitor must be calibrated annually to ± 5%.

b. Pressure monitor must be calibrated annually to within ± 5%.

## V. GAS CHROMATOGRAPH ("GC")

### A. General

a. Accuracy: The gas chromatography system shall be maintained to be accurate within 5% of full scale.

b. 8-Hour Repeatability (applies to all measured components except water):
± 0.5% of full scale for full scale ranges from 2-100%;
± 1% of full scale for full scale ranges from 0.05-2%;
± 2% of full scale for full scale ranges from 50-500 ppm;
± 3% of full scale for full scale ranges from 5-50 ppm;
± 5% of full scale for full scale ranges from 0.5-5 ppm.
The 8-Hour Repeatability range for water shall not be more than ± 3% of full scale.

c. The minimum sampling frequency shall be one sample every 15 minutes.

d. The GC shall be capable of speciating all gas constituents listed in Appendix FLR-10.

e. The sampling system shall be heat traced and maintained at 240°F with no cold spots. All system components shall be heated, including the probe, calibration valve, sample lines, sampling loop (or sample introduction system), and GC oven.

f. Where technically feasible, the sampling location should be at least two equivalent duct diameters downstream from the nearest control device, point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate occurs. The location should not be close to air in-leakages. Where technically feasible, the location should also be at least 0.5 diameter upstream from the exhaust or control device.

**B. <u>Gas Chromatograph Calibration Standards</u>**

1. **<u>Net Heating Value and Analyte Measurements</u>**. For the Net Heating Value and Analyte measurements, the GC shall be operated and maintained in accordance with Performance Specification 9 ("PS9") of Appendix B of 40 C.F.R. Part 60 except:

a. The daily mid-level validation procedure in Section 10.2 shall be conducted on the calculated Net Heating Value of the certified calibration gas based upon the concentration of each analyte. The average instrument response shall not vary by more than 10 percent from the Net Heating Value of the certified calibration gas.

b. The multi-point calibration error check procedure in Section 10.1 shall be conducted quarterly for the limited set of analytes listed in Subparagraph V.B.1.c below. No calibration will be required after routine maintenance or repair. The GC must meet the calibration performance criteria in Sections 13.1 and 13.2 of PS9 for the listed analytes only, such that: (i) the average instrument response must not differ by more than 10 percent of the calibration gas value; and (ii) the precision and linearity check of each analyte listed below shall not deviate more than 5 percent from the average concentration measured.

c. The analytes to be used are:

i. Hydrogen
ii. Nitrogen
iii. Methane
iv. Ethane
v. Propane
vi. Propylene
vii. Ethylene

d. The calibration gas mixtures may be set by the procedures identified in Section 7.1 of PS9 or may be within 10 percent of the concentration values listed in Table 1. The gases must be certified to ± 2 percent.

**<u>Table 1: Calibration Gas Mixtures for Net Heating Value Calibrations/Validations(1)</u>**

| Component | Daily Mid-Level Gas | Quarterly Low-Level Gas | Quarterly Med-Level Gas | Quarterly High-Level Gas |
|---|---|---|---|---|
| **Hydrogen** | **30** | **8** | **30** | **12** |

| Component | Daily Mid-Level Gas | Quarterly Low-Level Gas | Quarterly Med-Level Gas | Quarterly High-Level Gas |
|---|---|---|---|---|
| Nitrogen | 8 | 65 | 8 | 5 |
| Methane | 48 | 22 | 48 | 30 |
| Ethane | 3 | 2 | 3 | 30 |
| Propane | 2 | 1 | 2 | 15 |
| Propylene | 8 | 1 | 8 | 5 |
| Ethylene | 1 | 1 | 1 | 3 |
| NHV (Btu/scf) Unadjusted for H2 | 793 | 310 | 793 | 1273 |

(1) The individual analytes in this Table are in volume percent.

2. **<u>$H_2S$ Measurement</u>**. For the $H_2S$ measurement, the GC shall be operated and maintained in accordance with Performance Specification 7 of Appendix B of 40 C.F.R. Part 60. Quality assurance procedures set forth in Appendix F of 40 C.F.R. Part 60 shall be followed. The span shall be set at 320 ppmv $H_2S$ or as required by NSPS Subpart Ja, if different.

## VI. <u>Calculation of Instrument Downtime</u>

1. For purposes of calculating the 110 hours per calendar quarter of instrument downtime allowed pursuant to Paragraphs 17 and 51, the time used for GC calibration and validation activities required by Subparagraph V.B.1 of this Appendix may be excluded.

2. Any hour that meets the requirements of 40 C.F.R. § 60.13(h)(2) shall not be counted toward instrument downtime. Specifically:

(i) For a full operating hour (any clock hour with 60 minutes of unit operation), if there are at least four valid data points to calculate the hourly average (that is, one data point in each of the 15-minute quadrants of the hour), then there is no period of instrument downtime;

(ii) For a partial operating hour (any clock hour with less than 60 minutes of unit operation), if there is at least one valid data point in each 15-minute quadrant of the hour in which the unit operates to calculate the hourly average, then there is no period of instrument downtime; and

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour and if there are at least two valid data points separated by at least 15 minutes to calculate the hourly average, then there is no period of instrument downtime; or

(B) If the unit operates in only one quadrant of the hour and if there is at least one valid data point to calculate the hourly average, then there is no period of instrument downtime.

## VII. METEOROLOGIC STATION

a. Wind speed sensors must be calibrated annually to +/- 10%.

# APPENDIX FLR-12

**WASTE GAS MAPPING:**
**LEVEL OF DETAIL NEEDED TO SHOW HEADERS AND PROCESS UNIT HEADERS**

## Purpose:

Waste Gas Mapping is required in order to identify the source(s) of waste gas entering each Covered Flare. Waste Gas Mapping can be done using instrumentation, isotopic tracing, acoustic monitoring, and/or engineering estimates for all sources entering a flare header (e.g. pump seal purges, sample station purges, compressor seal nitrogen purges, relief valve leakage, and other sources under normal operations). Appendix FLR-15 outlines what needs to be included as the Waste Gas Mapping section within the Initial Waste Gas Minimization Plan ("Initial WGMP")

## Waste Gas Mapping Criteria:

For purposes of waste gas mapping, a main header is defined as the last pipe segment prior to the flare knock out drum. Process unit headers are defined as pipes from inside the battery limits of each process unit that connect to the main header. For process unit headers that are greater than or equal to six (6) inches in diameter, flow ("Q") must be identified and quantified if it is technically feasible to do so. In addition, all sources feeding each process unit header must be identified and listed in a table, but not necessarily individually quantified. For process unit headers that are less than six (6) inches in diameter, sources must be identified, but they do not need to be quantified.

## Waste Gas Mapping Submission Requirements:

For each Covered Flare, the following shall be included within the Waste Gas Mapping section of the Initial WGMP:

1. Simplified Schematic consistent with the example schematic included on the second page of this Appendix.

2. Table of all sources connected to each flare main header and process unit header consistent with the Table included on the third page of this Appendix.

# APPENDIX FLR-12

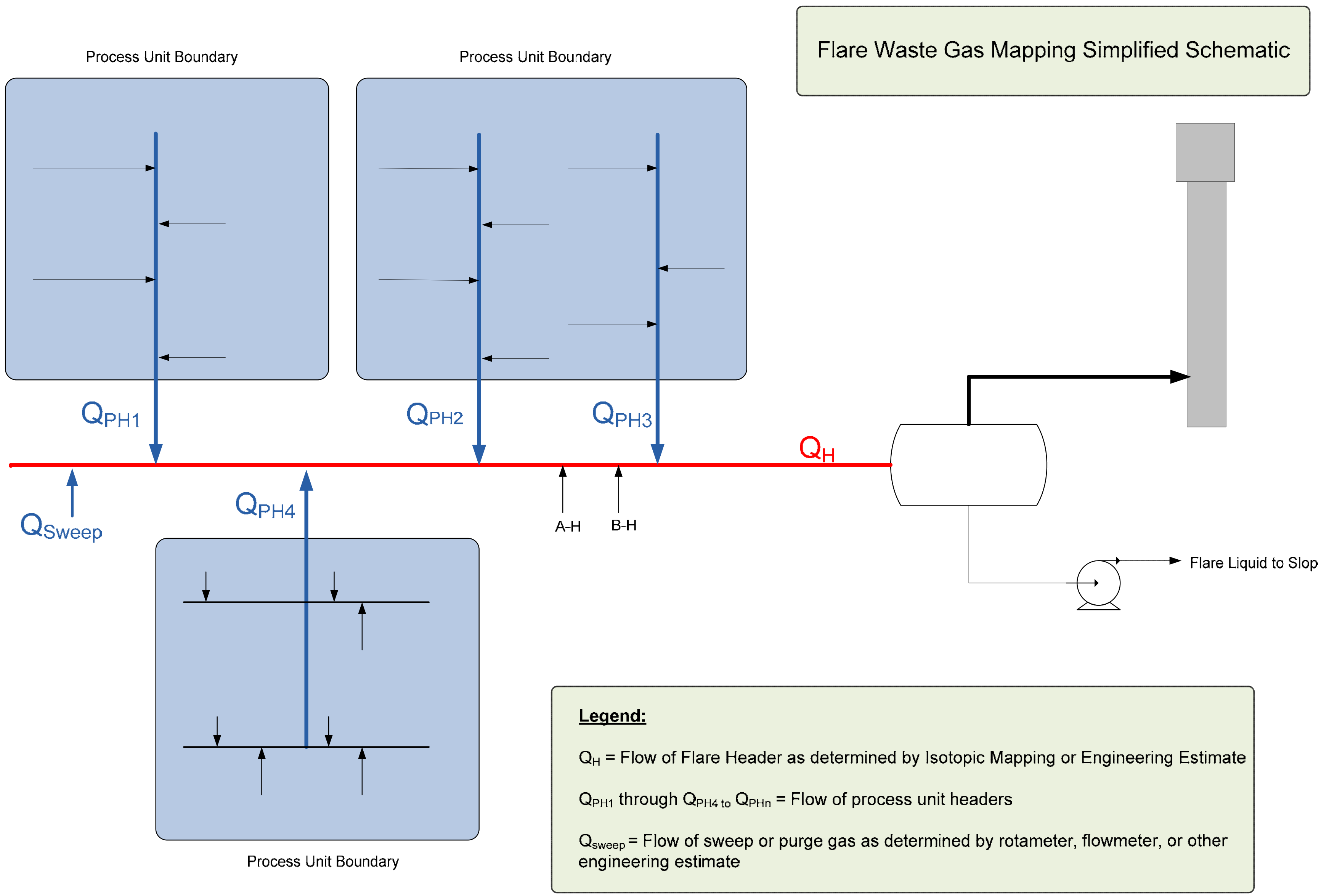


Table 1: Example of Flare Source Description Table

| Process Unit Header | Sources | Detailed Source Description |
|---|---|---|
| QS1<br>(Ex: FCCU Gas Con Unit) | 3 PSVs | PSV-14 on 110-D-5 Gas Con Absorber<br>PSV-12 on 110-D-1 Amine Scrubber<br>PSV-7 on 110-F-1 Batch Caustic Vessel |
| | 2 Pump Seal Purges | 110-G-1 LPG Pump<br>110-G-2 Rich Amine Pump |
| | 1 Sample Station | 110-S-1 LPG |
| | 1 PSV | PSV 17 on 112-D-1 Main Column |
| | 1 Pressure Control Valve | PCV 21 – Emergency Wet Gas Compressor |
| | 1 PSV | PSV-21 on Flush Oil Drum |
| | 1 Pump Seal Purge | 110-G-23 Slurry Oil Pump |
| QS2<br>(Ex: Gas Oil Treater) | Continue same as QS1 | Continue same as QS1 |
| QS3 | Continue same as QS1 | Continue same as QS1 |
| QS4 | Continue same as QS1 | Continue same as QS1 |
| A-H | 1 PSVs | PSV-17 on 109-E-42 Slurry Heat Exchanger |
| B-H | 2 Pump Seal Purges | 110-G-3 Gas Oil Feed<br>110-G-4 Main Column Reflux |

# APPENDIX FLR-13

## REPRESENTATIONS OF DISCONTINUOUS WAKE DOMINATED FLOW

**Definition**

"Discontinuous Wake Dominated Flow" shall mean gas flow exiting a Flare tip that is identified visually by:

i. the presence of a flame that is: (1) immediately adjacent to the exterior of the Flare tip body; and (2) below the exit plane of the Flare tip; and

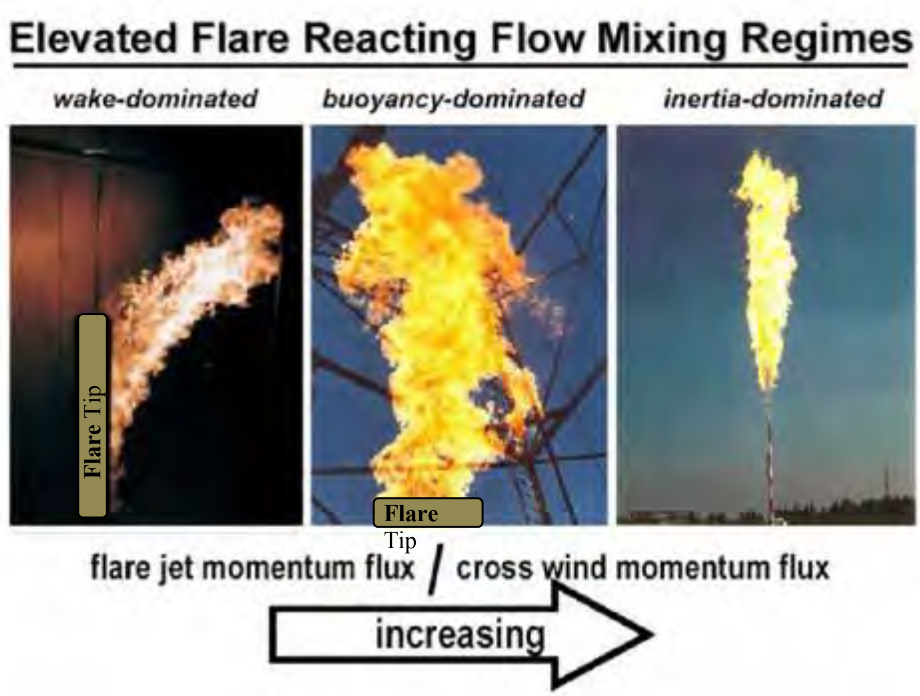
ii. a discontinuous flame, such that pockets of flame are detached from the portion of the flame that is immediately adjacent to the exterior of the Flare tip body.

**Background**

The gases present just outside of the flare tip are influenced by several factors. All of these factors are present all of the time, but as process and environmental conditions change, the relative "strength" of each factor will change. The most dominant factors will dictate the flow of the Vent Gases, *i.e.*, will determine the size, shape, and direction of the flame. Some of the influences on the Vent Gases are:

- The low pressure region, or wake, that is downwind and next to the flare.
- The temperature gradient that causes the warm combustion gases to be buoyant, or rise.
- The inertia, or resistance to changes in speed and direction, of the Vent Gases as they exit the tip.

The regimes below show how a flame will appear when the most dominant influences are, respectively, the wake, the buoyancy due to temperature, and the inertia due to the gas's momentum.




Images take from: Practical Implications of Prior Research on Today's Outstanding Flare Emissions Questions and a Research Program to Answer Them
James Seebold, ChevronTexaco (Retired)
Peter Gogolek, Natural Resources Canada
John Pohl, Virginia Polytechnic Institute and State University
Robert Schwartz, John Zink Company LLC

As a wake dominated flame becomes less stable, it becomes segmented, or discontinuous. The following is a representation of "Discontinuous Wake Dominated Flow." The red area is an artist's rendition of a flame.

The following image represents a flame below the plane of the exit of the flare tip. However, since the flame is not discontinuous and not immediately adjacent to the tip, this image would not represent Discontinuous Wake Dominated Flow.

The following image represents a flame below the plane of the exit of the flare tip and attached to the tip. However, since the flame is not discontinuous, this image would not represent Discontinuous Wake Dominated Flow.

In order for the flame to be deemed discontinuous, it should be segmented, and not merely possess small pockets of flame at the outer boundary of a single large cohesive flame. Furthermore, a discontinuous flame will normally appear thin relative to its length, and lack a single bulbous core. The following image represents a flame with a small pocket of flame only at the outer edges of the broad main flame. This would not represent a discontinuous flame, and therefore would not be Discontinuous Wake Dominated Flow.

# APPENDIX FLR-14

## DETERMINING REFINERY-SPECIFIC AND INDUSTRY-AVERAGE COMPLEXITY THROUGH USE OF THE NELSON COMPLEXITY INDEX

For purposes of Paragraph 27 of the Consent Decree, the complexity of the Refinery is to be calculated using the following formula:

Equation 1

$$Complexity = \sum_{n=1}^{i} \left( \frac{NCI_i \times CAP_i}{CAP_{Dist}} \right)$$

Where:

| | | |
|---|---|---|
| $NCI_i$ | = | The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for Process i |
| $CAP_i$ | = | The throughput capacity for Process i in barrels per calendar day as identified by the most recent Oil & Gas Journal survey |
| $CAP_{DIST}$ | = | The Refinery's Crude Distillation Capacity in barrels per calendar day as reported in the most recent report submitted by BPP to the Department of Energy |

For purposes of Paragraph 27 of the Consent Decree, the industry average complexity is to be calculated using the following formula:

Equation 2

$$Industry\_Average\_Complexity = \sum_{n=1}^{i} \left( \frac{NCI_i \times ICAP_i}{ICAP_{Dist}} \right)$$

Where:

| | | |
|---|---|---|
| $NCI_i$ | = | The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for Process i |
| $ICAP_i$ | = | Total US throughput capacity for Process i in barrels per calendar day as identified by the most recent Oil & Gas Journal survey |
| $ICAP_{DIST}$ | = | Total US Crude Distillation Capacity in barrels per calendar day as identified by the most recent Oil & Gas Journal survey |

# APPENDIX FLR-14

**Table 1: 2011 Nelson Complexity Index Coefficients**

| Refining Process | NCI Coefficients |
|---|---|
| Distillation Capacity | 1.00 |
| Vacuum Distillation | 1.30 |
| Thermal Processes | 2.75 |
| Coking | 7.50 |
| Catalytic Cracking | 6.00 |
| Catalytic Reforming | 5.00 |
| Catalytic Hydrocracking | 8.00 |
| Catalytic Hydrorefining | 2.50 |
| Catalytic Hydrotreating | 2.50 |
| Alkylation | 10.00 |
| Polemerization | 10.00 |
| Aromatics | 20.00 |
| Isomerization | 3.00 |
| Lubes | 60.00 |
| Asphalt | 1.50 |
| Hydrogen (MCFD) | 1.00 |
| Oxygenates | 10.00 |
| Sulfur Extraction | 240.00 |

# APPENDIX FLR-15

## LIMITING AIR FLOW TO ENSURE ADEQUATE COMBUSTION EFFICIENCY FOR AIR-ASSISTED FLARES

All abbreviations, constants, and variables are defined in the Key at the end of this Appendix.

### Steps in the Calculations

### Step 1: Determine the concentration of the compounds in the Vent Gas

**If a Gas Chromatograph is used:** Determine the volume fraction of all prominent compounds in the vent stream.

**If a Gas Chromatograph is not used:** Determine the volume fractions from bag samples, engineering knowledge, or facility estimates.

### Step 2: Calculate oxygen molar demand at a stoichiometric ratio

The complete combustion of an organic compound comprised of a combination of carbon and hydrogen atoms is shown in Equation 1. In the event the Vent Gas contains hydrogen, the value for x is zero and for y is two.

$$C_xH_y + \left(x + \frac{y}{4}\right) O_2 \rightarrow xCO_2 + \left(\frac{y}{2}\right) H_2O \qquad \textbf{\textit{Equation 1}}$$

Therefore, the stoichiometric oxygen molar flow rate (moles/hr) for any given combustible compound flow is defined by Equation 2:

$$\dot{n}_{O2-stoich} = x_j \left(\frac{\dot{m}_{vg}}{MW_{vg}}\right)\left(x + \frac{y}{4}\right) \qquad \textbf{\textit{Equation 2}}$$

### Step 3: Calculate oxygen demand at stoichiometric conditions

The stoichiometric oxygen mass flow rate for the vent gas (lb/hr) is given by Equation 3.

$$\dot{m}_{O2-stoich-vg} = MW_{O_2} * \sum_{j=1}^{n} \dot{n}_{O2-stoich_j} \qquad \textbf{\textit{Equation 3}}$$

**Step 4: Calculate air mass flow rate at stoichiometric conditions**

The mass of air needed to reach a stoichiometric ratio based on the actual Vent Gas flow rate is given by Equation 4.

$$\dot{m}_{air-stoich-vg} = \frac{MW_{air}}{0.21 \cdot MW_{O_2}} * \dot{m}_{O2-stoich-vg}$$ ***Equation 4***

**Step 5: Calculate actual Assist Air mass flow rate (given air flow volume)**

If the assist air mass flow rate is not known directly (via flow meter) it can be calculated from the volumetric flow (typically from a fan curve):

$$\dot{m}_{air-assist} = \frac{MW_{air}}{385.5} * \dot{V}_{air-assist}$$ ***Equation 5***

**Step 6: Ensure that during flare operation, the following is met:**

$$\dot{m}_{air-assist} < 106 \cdot \dot{m}_{air-stoich-vg}$$ ***Equation 6***

**Key to the Abbreviations:**

$0.21 = mole\ fraction\ of\ oxygen\ in\ air (0.21\ lb{-}mol\ O_2/lb - mol\ air)$
$385.5 = molar\ volume\ of\ an\ ideal\ gas\ @\ 68°F\ and\ 1\ atm\ (scf/mole)$
$i = individual\ numbered\ compound\ from\ column\ i\ in\ Table\ 1\ (unitless)$
$j = individual\ numbered\ compound\ from\ column\ j\ in\ Table\ 1\ (unitless)$
$\dot{m}_{air-assist} = mass\ flow\ rate\ of\ assist\ air\ (lb/hr)$
$\dot{m}_{air-stoich-vg} = stoichiometric\ mass\ air\ flow\ rate\ for\ the\ vent\ gas (lb/hr)$
$\dot{m}_{O2-stoich-vg} = stoichiometric\ oxygen\ mass\ flow\ for\ the\ vent\ gas\ (lb/hr)$
$\dot{m}_{vg} = mass\ flow\ rate\ of\ vent\ gas\ (lb/hr)$
$MW_{O_2} = molecular\ weight\ of\ oxygen\ (32.0\ lb/lb{-}\ mol)$
$MW_{air} = molecular\ weight\ of\ air\ (28.9\ lb/lb{-}\ mol)$
$MW_{vg} = molecular\ weight\ of\ vent\ gas\ (lb/lb{-}\ mol)$
$n = list\ of\ individual\ compounds\ from\ Table\ 1\ (unitless)$
$\dot{n}_{O2-stoich} = stoichiometric\ oxygen\ mass\ flow\ for\ an\ individual\ compound\ (mol/hr)$
$\dot{V}_{air-actual} = volumetric\ flow\ of\ assist\ air\ (scf/hr)$
$x = moles\ of\ carbon\ per\ mole\ of\ C_xH_y\ (mol/mol)$
$x_j = individual\ combustible\ compound\ volume\ fraction\ in\ the\ vent\ gas\ (vol\ fraction)$
$y = moles\ of\ hydrogen\ per\ mole\ of\ C_xH_y\ (mol/mol)$

**Table 1**
**<u>Individual Compound Properties</u>**

| $I^{(1)}$ | j | Compound | $MW_i$ (lb/lbmol) | x + y/4 |
|---|---|---|---|---|
| 1 | 1 | Hydrogen | 2.02 | 0.5 |
| 2 | | Oxygen | 32.00 | 0 |
| 3 | | Nitrogen | 28.01 | 0 |
| 4 | | $CO_2$ | 44.01 | 0 |
| 5 | | CO | 28.01 | 0 |
| 6 | 2 | Methane | 16.04 | 2 |
| 7 | 3 | Ethane | 30.07 | 3.5 |
| 8 | 4 | Ethylene | 28.05 | 3 |
| 9 | 5 | Acetylene | 26.04 | 2.5 |
| 10 | 6 | Propane | 44.10 | 5 |
| 11 | 7 | Propylene | 42.08 | 4.5 |
| 12 | 8 | iso-Butane | 58.12 | 6.5 |
| 13 | 9 | n-Butane | 58.12 | 6.5 |
| 14 | 10 | iso-Butene, Butene-1, trans-Butene-2, cis-Butene-2 and 1,3 Butadiene combined | 56.11 | 6 |
| 15 | 14 | Pentane+ ($C_5$+) | 72.15 | 8 |
| 16 | | Water | 18.02 | 0 |

[1] i=all compounds, j=organic compounds and hydrogen

Note: Benzene and 1,3 butadiene are not required to be speciated by the Gas Chromatograph for this refinery settlement (*see* Appendix FLR-10) because benzene and 1,3 butadiene are present in the Vent Gas only in *de minimis* quantities. Because benzene and 1,3 butadiene speciation is not required, it is not listed in Table 1of this Appendix. The Vent Gas composition involved in other future settlements should be evaluated on a case-by-case basis to determine if benzene or 1,3 butadiene speciation should be required.

**APPENDIX FLR-16**

**COMBUSTION EFFICENCY TEST PROTOCOL**

## 1.0 Test Objectives

BPP is planning to conduct a performance test on a refinery flare. The flare is an elevated steam-assisted flare, with a XX[†] inches diameter flare tip manufactured by XXX[†] with an effective diameter of XX[†] inches. The tip has XX[†] steam injection points, XXX for center steam (if applicable), XXX[†] for lower steam, and XXX[†] for an upper steam ring. The primary objective of the flare performance test is to evaluate the impacts of combustion efficiency over a range of steam rates.

BPP is planning to conduct the test on (ADD DATES[†]). Passive Fourier Transform Infrared (PFTIR) instruments operated by (ADD VENDOR[†]) will be used to measure combustion efficiency of the flare.

## 2.0 Flare Performance Test

During the Test, the S/VG will be varied. Each steam ratio is defined as a “test run.” During each test run, one or more PFTIR analyzers will remotely analyze the combustion gases in the flare plume to determine combustion efficiency. The result will be a defined flare operating envelope defined by the incipient smoke point on one side and oversteaming on the other.

The Refinery is located within a populated region, and therefore, this test plan does not include evaluating combustion efficiency on plumes having visible emissions. Each Test series will begin at either the incipient smoke point or at the minimum cooling steam rate assuming it can be achieved without incurring visible emissions.

## 3.0 Procedure

The anticipated time for the test is about 2 to 4 hours or more depending on the number of steam flow conditions to be tested and atmospheric conditions. The duration of each test run will be approximately 15-30 minutes and will be synchronized to the GC analysis cycle.

Before the beginning of each Test, a minimum of two GC cycles will be examined to ensure something close to the expected flare vent gas composition has been achieved and to ensure it is reasonably stable. Once the test begins, each S/VG test run will be bracketed by GC results. The results from the end of one S/VG test period will serve as

[†] To be completed by BPP when submitting the protocol.

the results for the beginning of the next. If a comparison of all GC results shows a significant change (as defined below), then the S/VG test run will be repeated.

Once the flare operator receives each new GC analytical report and it appears that no significant composition changes have occurred, the operator will notify all test personnel. The PFTIR operator will respond as to whether he has been able to obtain sufficient data at that test run. If so, the flare operator will then adjust the steam mass flow rate to match the next S/VG ratio in the test matrix. The PFTIR operator will then begin to take measurements at the new test run. Since PFTIR measurements are affected by transient atmospheric conditions such as clouds and wind, the PFTIR operator will notify the flare operator if a test run must be held for more than the schedule test time due to a transient condition (see Section 7.0 for wind requirements). The PFTIR operator will periodically pull off the plume to perform a sky background adjustment on the analyzer. In all such cases, the synchronization between GC and PFTIR data will be maintained.

It is important to note that the base flare gas which is present at all times during testing may vary significantly in both flow and composition. During the Test, both flare gas and steam flow rates will be measured continuously with ultrasonic flow monitors. Determination of molecular weight of the flare gas will also be provided continuously. This data should allow operators to hold a steady S/VG ratio even as flow rates and composition varies.

A gas chromatograph to measure the composition of the flare vent gas or ultrasonic flow meter to determine the molecular weight of the flare vent gas will not be required at the Whiting Refinery LPG flare for PFTIR testing. Instead, Whiting personnel will collect and analyze sufficient samples to determine the representative composition and molecular weight of vent gas during the test period. The type and frequency of sampling will be agreed with the EPA as part of the testing protocol for the LPG flare.

Test runs representing the range of normal flare operations will be replicated at least two times over the course of the test program. This will allow a determination of the combustion efficiency variability for each test run over time. During the transition from one run to another, the flare may experience short periods of over-steaming due to potential limitations in the instrumentation and control logic response times. Smoking, however, must be avoided (even for short durations) due to the proximity of the surrounding community. The frequency and duration of such smoking periods will be recorded.

At the beginning and end of each test day, the PFTIR operator will calibrate the PFTIR according to the calibration protocol found in Appendix A. A Long Term Stability (LTS) test will be performed at the beginning of each test day.

## 4.0 Location

If two PFTIR instruments are used, they will be placed so that at least one instrument is capable of collecting valid data regardless of wind speed or direction.

***[ADD PLOT PLAN WITH FLARE LOCATION]***[†]

**Figure 1:** Map of equipment locations in relation to flare

[†] To be completed by BPP when submitting the protocol.

## 5.0 Data Collection

Data used for final analysis of flare performance will originate from several different sources. Each data set from the several sources will be combined for analysis at the end of the test program. The final data sets from the several sources, especially PFTIR measurements, may change after the test program due to more complete processing of the raw measurements.

### 5.1 Test Run Log

A log will be kept of each test run. Each log entry will include the start and stop times of the run as well as any events occurring during the run. Runs that are not completed will also have an entry and comment on why the run was not completed.

In addition to run times, each log entry will have a description of the conditions at which the run was performed. The entry will also note the visible emissions rating of the flare and any ambient factors that could affect the test performance (wind direction, cooling tower plume, etc.). The visible emissions rating scale is provided in Appendix C.

### 5.2 Process Data

Process data will be provided by plant operations and include process data, vent gas composition data, and meteorological data. Table 2 lists the parameters and time interval that will be recorded and delivered by plant operations. The gas chromatograph (GC) used for measuring flare gas composition will report the compounds listed in Table 3.

| Parameter | Unit | Frequency |
|---|---|---|
| Flare Gas Volumetric Flow Rate | scfh | 1 minute |
| Flare Gas Mass Flow Rate | lb/hr | 1 minute |
| Flare Gas Molecular Weight | lb/lb-mole | 1 minute |
| Flare Gas Composition | vol. % | 15 minutes |
| Estimated Pilot Gas Flow Rate | lb/hr | N/A |
| Steam Mass Flow Rate | lb/hr | 1 minute |
| Steam Temperature at Flow Measurement Point | °F | 1 minute |
| Flare Gas Combustion Zone Net Heating Value | BTU/scf | 15 minutes |
| Vent Gas Net Heating Value | BTU/scf | 15 minutes |
| Actual Total Steam to Vent Gas Ratio | -- | 1 minute |
| Hydrocarbon Mass Flow Rate | lb/hr | 15 minutes |
| Flare Exit Velocity | fps | 1 minute |
| Wind Direction | ° | 1 minute |
| Wind Speed | mph | 1 minute |
| Ambient Barometric Pressure | in. Hg | 1 minute |
| Ambient Temperature | °F | 1 minute |
| Ambient Humidity | % | 1 minute |
| Momentum Flux Ratio | -- | 1 minute |

**Table 2:** Process data parameters that will be reported

| Compound | Mol. Wt. | Range | Units |
|---|---|---|---|
| Hydrogen | 2.02 | 0 - 100 | mole % |
| Nitrogen | 28.02 | 0 - 100 | mole % |
| Oxygen | 32.00 | 0 - 100 | mole % |
| Carbon Dioxide | 44.01 | 0 - 100 | mole % |
| Carbon Monoxide | 28.01 | 0 - 100 | mole % |
| Methane | 16.04 | 0 - 100 | mole % |
| Ethane | 30.07 | 0 - 100 | mole % |
| Ethylene | 28.06 | 0 - 100 | mole % |
| Acetylene | 26.04 | 0 - 100 | mole % |
| Propane | 44.10 | 0 - 100 | mole % |
| Propylene | 42.08 | 0 - 100 | mole % |
| Iso-Butane | 58.12 | 0 - 100 | mole % |
| Normal Butane | 58.12 | 0 - 100 | mole % |
| iso-Butene, Butene-1, cis-butene-2, trans-butene-2 and 1,3 Butadiene combined | 56.11 | 0 - 100 | mole % |
| Pentane-Plus (C5+) | 72.15 | 0 - 100 | mole % |

**Table 3:** Compounds reported by the GC for flare gas composition

## 5.3 PFTIR

PFTIR instruments from [INSERT VENDOR] will be used to measure combustion efficiency of the flare. The PFTIR instruments will be equipped with dual sensors - mercury-cadmium-telluride (HgCdTe) and indium-antimonide (InSb). If two PFTIR instruments are used to conduct measurements during a test run, then each instrument will be located 90° around the base of the flare to the other (see Figure 1). The perpendicular placement of the two instruments will allow one instrument to have an adequate plume cross-section for any wind direction (see Section 6).

PFTIR data will be logged into the data acquisition system supplied by the PFTIR contractor. PFTIR measurements will be provided for analysis on a minute-by-minute timeline. The reported values will constitute an average of several analytical cycles over each test run. The software used by the PFTIR contractor is proprietary but will perform analyses and report data in accordance with the specifications found in Appendix A. Table 4 lists the compounds to be measured.

The Test Report shall state which wave number was used for quantification of $CO_{2,}$ and shall compare and discuss 765 and 2000 wave number data.

| Compound | Unit |
|---|---|
| Carbon Dioxide ($CO_2$) | ppm x m |
| Carbon Monoxide (CO) | ppm x m |
| Methane ($CH_4$) | ppm x m |
| Ethylene ($C_2H_4$) | ppm x m |
| Propane ($C_3H_8$) | ppm x m |

| Compound | Unit |
|---|---|
| Propylene ($C_3H_6$) | ppm x m |
| Butane ($C_4H_{10}$) | ppm x m |
| 1,3 Butadiene ($C_4H_6$) | ppm x m |
| Total Hydrocarbon (THC) | ppm x m |

**Table 4:** Compounds reported by the PFTIR

### 5.4 Video

Both thermal and visual video recordings will be collected and stored. A timestamp for each image will saved with the video so the video can be reference to each test run.

One aiming camera mounted to each PFTIR will record the point at which the PFTIR is pointed. One high definition visual color camera will be beside each PFTIR to record the overall flare flame and plume. One infrared camera will be beside each PFTIR to record the thermal image of the flare plume. Specifications on the video cameras are located in Appendix B.

## 6.0 Stability of Flare

It should be understood that because this test program is being conducted on a working refinery flare, it might not always be possible to maintain stable conditions throughout the duration of a test run. The flow rates and flare gas composition could be changing throughout the duration of each test run.

In order to generate reliable data, it is necessary to define conditions under which the variability of flare gas flow or composition occurring during the test period is large enough to warrant concern over data quality. Therefore, at the end of each test period, we will calculate whether the variability in vent gas flow rate or composition during the test period would have resulted in an S/VG ratio that would be more than 25% different than the S/VG ratio at which the test was conducted. If this is found to be the case, the test run will be repeated once a stable flow rate and composition can be maintained.

During test runs calling for the S/VG ratio, the steam mass flow may change over the test period based on vent gas flow, but the ratio will remain constant.

## 7.0 Wind Direction Impacts

Because a PFTIR measures the thermal radiation of hot gases passively, it is sensitive to other background and environmental variables. A consistent cross-section of the plume must be measured to obtain a representative area of the plume. Therefore, a PFTIR cannot operate under certain wind conditions that would prevent an adequate plume cross-section.

When the wind blows the flare plume away or towards a PFTIR location, a good cross-section of plume cannot be measured. A wind restriction of +/-30 degrees downwind and upwind will be applied to the test program (see Figure 2). Only data from the PFTIR location with a good cross-section of the flare plume will be considered valid.

If other ambient conditions prevent collection of a representative sample by either PFTIR, the test program will be paused to allow those ambient conditions to subside. Examples of such conditions may include cooling tower plume interference, rain or fog, and abrupt changes in wind direction.

***[ADD WIND ROSE MAP]***[†]

**Figure 2:** Restricted wind directions for PFTIR locations

[†] To be completed by BPP when submitting the protocol.

## 8.0 Calibration

Radiance calibrations will be conducted at least once each day with a blackbody IR source located at roughly the same distance from the PFTIR as the flare. This involves pointing the PFTIR at the black body IR source to collect the radiance of the air between the source and the PFTIR. This radiance is the transmission radiance between the flare plume and the PFTIR.

Background radiance calibrations will be performed as needed when the background ambient conditions change throughout the day. At minimum, a background radiance calibration will be performed once per run. This involves pointing the PFTIR at the sky behind the flare plume without including and plume. This radiance is the background radiance behind the flare plume.

By removing the transmission radiance and the background radiance from the measured radiance when the PFTIR is pointing at the flare plume, the plume radiance is isolated and can be analyzed for concentration x pathlength.

In order to challenge the PFTIR with known concentrations of gas, hot cell calibrations will be performed prior to the test program. In this calibration, a known mixture of $CO_2$, CO, and methane are metered by mass flow controllers into a heated cell. This cell is placed at the focal point of the collimator used for the radiance and other calibrations and which is located at a distance from the PFTIR. The PFTIR then collects data from the cell and the data is reduced to produce a concentration result. This result is then compared to the known value of the calibration gas concentration. From this hot cell calibration data, calibration curves will be produced and can be used for calibration factors that will be applied to the measured flare plume data.

# 9.0 Camera Operation and Calibration

## 9.1 Thermal – FLIR

The FLIR is a stand-alone thermal measurement camera that can determine the temperature of objects within 2°C or 2% of its calibration range. It has an internal computer that calculates object temperatures and outputs a false color image of the camera's field of view. A scale of temperatures is displayed on the image to show what the range of the color palate is. The FLIR also has the ability to display custom areas in the image as an average temperature.

A FLIR camera measures the infrared radiance of objects in its field of view. The temperature readings from the FLIR camera are calibrated to the radiance from NIST-traceable black body sources. However, the FLIR cameras used in this test plan will be attempting to measure the flare plume temperature, which is not a solid object.

Therefore, temperature measurements by the FLIR cameras are biased low because the plume gas is semi-transparent at the wavelengths measured (7.5-13.0µm). The main use of the FLIR cameras will be to identify when the flare flame is about to snuff due to over steaming.

## 9.2 Visible Light Camera

The visible light camera outputs a high definition 720p or 1080i resolution image at 25 or 30 frames per second and 16:9 aspect ratio. It has a 10x optical zoom and auto focus. The purpose of the camera is to record how the flare flame appears during testing.

## 9.3 Aiming Cameras

The PFTIR at each location will need to be aimed at the flare plume when they are collecting data. An infrared camera will be mounted on each PFTIR to assist with aiming. Two types of infrared cameras can be used for mounted aiming: the NEC/Mikron TH5104 (color) or equivalent and the Agema Thermovision 510 (black & white) or equivalent. Both use a bandpass of 3-5µm.

# 10.0 Visual Emissions Scale

| Flame Rating | Flame Characteristic |
|---|---|
| 0 | Steam plume |
| 1 | Transparent |
| 2 | Mostly transparent, with occasional yellow flame. |
| 3 | Mostly yellow flame, with occasional transparency. |
| 4 | Yellow to orange flame. |
| 5 | Orange flame with some dark areas in the flame. (Incipient smoke point) |
| 6 | Orange flame with light smoke trail. |
| 7 | Clear steam at the flare tip, with an orange flame and a light smoke trail. |
| 8 | Orange flame with dark smoke trail leaving the flame. |
| 9 | Orange flame with heavy dark smoke trail leaving the flame. |
| 10 | Billowing black smoke |

**Table C-1:** Visual emissions and flame rating scale

# APPENDIX FLR-17

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# APPENDIX FLR-18

## Calculating Sulfur Dioxide Emissions From Reportable Flaring Incidents

1. Calculating the Quantity of Sulfur Dioxide Emissions from Acid Gas and Hydrocarbon Flaring Incidents

   a. The quantity of $SO_2$ emissions resulting from an AG and HC Flaring Incidents shall be calculated by the following equation:

   Tons of $SO_2$ = [FR][TD][ConcS][8.44 x 10-5] *(Equation 1)*

   b. The meaning of the variables is set forth in Paragraph 3.

   c. The quantity of $SO_2$ emitted shall be rounded to one decimal point. (Thus, for example, for a calculation that results in a number equal to 10.050 tons, the quantity of $SO_2$ emitted shall be rounded to 10.1 tons.)

   d. For purposes of determining the occurrence of, or the total quantity of $SO_2$ emissions resulting from, an Acid Gas or Hydrocarbon Flaring Incident that is comprised of intermittent Flaring, the quantity of $SO_2$ emitted shall be equal to the sum of the quantities of $SO_2$ emitted during each 24-hour period starting when the gas was first flared.

2. Calculating the Rate of Sulfur Dioxide Emissions During Acid Gas or Hydrocarbon Flaring.

   a. The rate of $SO_2$ emissions resulting from an Acid Gas or HC Flaring Incident shall be expressed in terms of pounds per hour and shall be calculated by the following formula:

   ER = [FR][ConcS][0.169] *(Equation 2)*

   b. The meaning of the variables is set forth in Paragraph 3.

   c. The emission rate shall be rounded to one decimal point. (Thus, for example, for a calculation that results in an emission rate of 19.95 pounds of SO2 per hour, the emission rate shall be rounded to 20.0 pounds of SO2 per hour; for a calculation that results in an emission rate of 20.05 pounds of SO2 per hour, the emission rate shall be rounded to 20.1.)

[Appendix FLR-18 is continued on next page]

3. Meaning of Variables and Derivation of Multipliers Used in the Equations 1 and 2:

ER = Emission Rate in pounds of $SO_2$ per hour

FR = Average Flow Rate during the Flaring Incident in standard cubic feet per hour

TD = Total Duration of Flaring Incident in hours

ConcS = Average Concentration of Sulfur in gas during Flaring Incident (or immediately prior to Flaring Incident if all gas is being flared) expressed as a volume fraction (scf S/scf gas).

8.44 x 10-5 = [lb mole S/379 scf S][64 lb $SO_2$/lb mole S][Ton/2000 lb]

0.169 = [lb mole S/379 scf S][1.0 lb mole $SO_2$/lb mole S] [64 lb $SO_2$/1.0 lb mole $SO_2$]

The flow of gas to the Flaring Device(s) ("FR") shall be as measured by the relevant flow meter or reliable flow estimation parameters. Sulfur concentration ("ConcS") shall be determined from the Sulfur Recovery Plant feed gas analyzer, an appropriate flare gas sulfur content analyzer (H2S, TRS, or total sulfur), from knowledge of the sulfur content of the process gas being flared, by direct measurement by tutwiler or draeger tube analysis, or by any other method approved by EPA or IDEM. In the event that any of these data points is unavailable or inaccurate, the missing data point(s) shall be estimated according to best engineering judgment. The report required to be prepared under Paragraph 54 shall include the data used in the calculation and an explanation of the basis for any estimates of missing data points.

4. Calculating the Quantity of Sulfur Dioxide Emissions from Tail Gas Incidents – Trigger 1. For Tail Gas Incidents – Trigger 1, where, by definition, the Tail Gas is combusted in a flare, the quantity of SO2 emissions is calculated using Equation 1.

[Appendix FLR-18 is continued on next page]

5. Calculating the Quantity of Sulfur Dioxide Emissions From Tail Gas Incidents – Trigger 2. For Tail Gas Incidents – Trigger 2, where, by definition the Tail Gas is combusted in a thermal incinerator, the quantity of SO2 emissions is calculated using the following equation:

$ER_{TGI}$ = $TD_{TGI}$
ÿ $[\ FR_{Inc.}]_i$ $[Conc.\ SO_2 - 250]_i$ $[0.169 \times 10^{-6}]_i$ $[(20.9 - \%\ O_2)/20.9]_i$
i = 1

*(Equation 3)*

Where:

$ER_{TGI}$ = Emissions from Tail Gas at the incinerator, $SO_2$ lb per 24-hour period

$TD_{TGI}$ = Total Duration (number of hours) when the incinerator CEMS exceeded 250 ppmvd $SO_2$ corrected to 0% $O_2$ on a rolling twelve hour average, in each 24 hour period of the Incident

i = Each hourly average

$FR_{Inc.}$ = Incinerator Exhaust Gas Flow Rate (standard cubic feet per hour, dry basis) (actual stack monitor data or engineering estimate based on the acid gas feed rate to the SRP) for each hour of the Incident

Conc. $SO_2$ = Each actual 12 hour rolling average $SO_2$ concentration (CEMS data) that is greater than 250 ppm in the incinerator exhaust gas, ppmvd corrected to 0% $O_2$, for each hour of the Incident.

% $O_2$ = $O_2$ concentration (CEMS data) in the incinerator exhaust gas in volume % on dry basis for each hour of the Incident

$0.169 \times 10^{-6}$ = [lb mole of $SO_2$ / 379 $SO_2$] [64 lbs $SO_2$ / lb mole $SO_2$] [$1 \times 10^{-6}$]

Standard conditions = 68 degree F; 14.7 $lb_{force}$/sq.in. absolute

In the event the concentration $SO_2$ data point is inaccurate or not available or a flow meter for $FR_{Inc}$ does not exist or is inoperable, then BP shall use estimates based on best engineering judgment.

[End of Appendix FLR-18]

**APPENDIX E**

**FENCE LINE MONITORING SYSTEM SUPPLEMENTAL ENVIRONMENTAL PROJECT**

BPP will install, operate and maintain a fence line monitoring system and make the data collected available to the public pursuant to the requirements of Section VII.A of the Consent Decree, and in accordance with the specifications and criteria identified in this Appendix.

**A. Equipment:** The monitoring system shall consist of four monitoring stations, each of which shall be equipped with the following equipment:

1. Instruments capable of measuring and recording the concentrations of the following compounds in air at a minimum detection level of 0.5 parts per billion by volume (ppbV) for benzene and toluene, and 1.0 ppbV for the following gaseous analytes:

   Pentane
   Hexane
   Sulfur dioxide
   Hydrogen sulfide
   Reduced sulfur compounds (defined as all compounds containing reduced sulfur measured as an aggregate sum)

   The monitoring equipment shall be capable of measuring the gases at the above-referenced concentrations and the data recording system shall reduce those measurements to hourly averages.

   Within 60 days of the Date of Entry of this Consent Decree, BPP shall provide EPA with a Fence Line Monitoring Plan to include, at a minimum, identifying the locations of the meteorological station and each of the monitoring stations and how those sites meet the requirements of this Appendix; a Quality Assurance Project Plan (QAPP) that describes the Quality Assurance/Quality Control procedures, specifications, and other technical activities to be implemented to ensure that the results of the Fenceline Monitoring SEP meets project specifications; and implementation of the data availability requirements of this Appendix.

   a. SO$_2$, Reduced Sulfur Compounds and H$_2$S. Ambient concentrations of sulfur dioxide (SO$_2$) will be continuously measured using Teledyne-API Model T100 or equivalent in accordance with 40 C.F.R. Part 53, Subparts A and C. The SO$_2$ monitor shall be operated and maintained in accordance with all corresponding EPA equivalent method requirements. The SO$_2$ monitors will be operated in the 0 to 0.50 ppm full scale measurement range with temperature and pressure compensation features activated. For Hydrogen Sulfide (H$_2$S) and reduced sulfur compounds, the Teledyne API Model T101 or equivalent will be operated in switching mode to provide alternate 5-minute data for H$_2$S, then reduced sulfur compounds. The monitors shall be operated and maintained in accordance with the manufacturer's recommendations and shall be capable of measuring reduced sulfur compounds and $H_2S$, with a lower detection level of 1.0 ppb.

b. Benzene, Toluene, Pentane, and Hexane. The continuous measurement of benzene, toluene, pentane, and hexane shall be accomplished using an SRI Model 8610 auto-GC or equivalent. The automated GC monitors shall be operated and maintained in accordance with the manufacturer's recommendations and shall have a calibration range of 1.0 to 500 ppbV for all gases. The GC monitors shall operate with a one hour cycle time with ambient air samples collected over an approximate 40 minute period during each hourly cycle.

Nothing in this Appendix E shall preclude the use of any other, additional fenceline monitoring equipment and/or monitoring of any other, additional pollutants at the fenceline of the Whiting Refinery.

2. Instruments for Measuring and Recording Wind Speed, Wind Direction, Ambient Temperature, Humidity and Barometric Pressure. Specific meteorological parameters will be continuously monitored to obtain data representative of prevailing meteorological conditions for the Whiting refinery area. The data set produced shall be adequate to correlate prevailing conditions with pollutant measurements and transport.

a. Continuously measured meteorological parameters shall include hourly-averaged (scalar or vector) measurements of horizontal wind speed and wind direction, the standard deviation of the horizontal wind direction (sigma theta), air temperature and relative humidity. Wind speed and direction shall be measured at a height of approximately 10 meters. Temperature, relative humidity, and barometric pressure shall be measured at a height of 2 to 3 meters.

b. Wind direction and sigma theta measurement data shall be compiled and reported as hourly block averages in degrees ($^{o}$), rounded to the nearest whole degree. Wind speed data measurement data shall be compiled and reported as hourly block averages in miles per hour (mph), rounded to the nearest tenth of a mph.

c. Air temperature measurement data will be compiled and reported as hourly block averages in degrees Fahrenheit ($^{o}$F) or Celsius ($^{o}$C), rounded to the nearest tenth of a degree.

d. Relative humidity measurement data will be compiled and reported as hourly block averages in percent, rounded to the nearest whole percent.

3. Monitoring Station. Monitoring equipment (except meteorological monitors and their support towers) shall be installed and operated inside a temperature-controlled equipment shelter. The temperature within each shelter shall be continuously monitored and recorded using a calibrated RTD and microprocessor- or PC-based data acquisition system (DAS or data logger). The climate control

system for each monitoring shelter will be capable of maintaining a stable temperature within the range of 20° C to 30° C.

Typically, the monitoring shelters will measure 8 feet wide by 12 feet long by 8 feet high. Each shelter will be anchored and secured to a concrete pad for safety. A padlocked exterior compartment attached to an outer wall of the shelter will safely house all compressed support gases. Shelters walls and roof will have a minimum insulation rating of R11. Each shelter will be equipped with electrical service panels, interior electrical distribution circuits, lighting, workbench and sufficient space for housing, operating and maintaining the monitoring instruments. All electrical wiring and appurtenances will conform to the National Electric Code (NEC). Each shelter electrical service and the shelter building itself will be grounded to earth in conformance with NEC and local code requirements.

Monitoring shelters located within the refinery shall maintain a slight (*e.g.*, 0.013 to 0.026 Bar) internal positive air pressure with respect to atmospheric air pressure.

**B.** **Locations –** The four monitoring stations shall be located on Whiting Refinery property near the Refinery fence line at up- and down-wind locations to be determined by BPP in consultations with EPA and interested members of Whiting's Community Advisory Committee (CAC), and in consideration of the following siting criteria:

a. The up- and down-wind locations should be determined by the last 5 years of NOAA data from the most appropriate National Weather Service (NWS) or from the Indiana Department of Environment Management (IDEM) Gary, Indiana monitoring station. The meteorological data (resultant wind direction and wind speed hourly averages) will be used to construct wind roses for the site.

b. Availability of land, accessibility to site, availability of utility services, and security of monitors and operating personnel.

c. Geographic spacing of sites relative to the refinery for monitoring upwind and downwind concentrations.

d. Probe or sampler inlet should be 2 to 5 meters above ground and have unrestricted airflow 270 degrees around the sample inlet probe or 180 degrees if the probe is on the side of a building.

e. Probe or sampler inlet should be >20 meters from the dripline of any tree(s).

f. $SO_2$, TRS, and VOC probes should be >1 meter away from supporting structures, walls and parapets.

g. The distance from a sampler probe to an obstacle, such as a building, should be at least twice the height the obstacle protrudes above the sampler, probe, or monitoring path.

h. All probes and samplers should be away from minor sources, such as incineration flues, to avoid undue influences from minor sources. The separation distance is dependent on the height of the minor source's emission point (such as a flue), the type of fuel or waste burned, and the quality of the fuel.

**C.** **Operation –** BPP shall operate and maintain the monitors and equipment described herein in accordance with manufacturers' recommendations for a period of no less than: (a) two years after installation and startup of the four monitoring stations, or (b) for a longer period, if necessary to meet the requirements of Paragraph 88 of the Consent Decree with respect to the total amount of money required to be expended.

**D.** **Quality Assurance/Quality Control (QA/QC) –** BPP shall ensure that all data collected by the Fence Line Monitoring System is subjected to appropriate QA/QC procedures on a monthly basis. The QA/QC procedures for a given month's data shall be completed by no later than the end of the month following the month within which the data were collected.

**E.** **Data Availability –** On a weekly basis, BPP shall post the Fence Line Monitoring System data on a dedicated website or through BPP Whiting's internet homepage ("Monitoring Data Website"), in a manner that shall be readily accessible, clearly labeled, and clearly presented to the public. BPP shall additionally post on the Monitoring Data Website, on a quarterly basis, CEMS emissions reports submitted to IDEM and/or USEPA pursuant to the Title V permit for all refinery units that are monitored by CEMS. BPP shall maintain data collected through the Fence Line Monitoring System on the Monitoring Data Website for at least five years from the date of its collection, and shall review the Fence Line Monitoring Data with the CAC members as they may request.

**F.** **General Provisions –**As required by Paragraph 88, BPP shall expend not less than $2 million in costs or expenditures to perform this SEP. For purposes of this SEP, "costs or expenditures" shall mean the costs or expenditures required to purchase, install, operate and maintain the monitoring equipment required by this SEP for a 2 year period, and at a cost of not less than $2 million.

# APPENDIX F

## FOVs and NOVs

United States Environmental Protection Agency
Region 5

| | | |
|---|---|---|
| IN THE MATTER OF: | ) | FINDING OF VIOLATION |
| | ) | |
| BP Products North America | ) | EPA-5-07-IN-03 |
| Whiting, Indiana | ) | |
| | ) | |
| | ) | |
| Proceedings Pursuant to | ) | |
| the Clean Air Act, | ) | |
| 42 U.S.C. §§ 7401 et seq. | ) | |

### FINDING AND NOTICE OF VIOLATION

BP Products North America, Inc. (BP or you) owns and operates a petroleum refinery at 2815 Indianapolis Boulevard, Whiting, Indiana (BP Whiting). The refinery consists of a number of pieces of equipment that generate air pollution and are subject to provisions of the Clean Air Act (the Act). This includes a sulfur recovery plant consisting of three Claus sulfur recovery trains, two tail gas units, a standby incinerator, and a modular degassing unit (also referred to as the "sulfur pit").

U.S. EPA is sending this Finding and Notice of Violation (FOV/NOV) to you for sulfur dioxide ($SO_2$) emissions from the sulfur recovery plant in excess of limits found in the Indiana State Implementation Plan (SIP) and the "Standards of Performance for Petroleum Refineries," at 40 C.F.R. Part 60, Subpart J (Refinery NSPS), for excessive hydrogen sulfide ($H_2S$) emissions caused by violations of control requirements found in an Indiana SIP required construction permit designated as Significant Source Modification (SSM) 089-13846-00003, as amended by Administrative Amendment (AA) 089-15525-00003, and for failing to maintain good air pollution control practices as required by the general provisions of the New Source Performance Standards (NSPS), at 40 C.F.R. Part 60, Subpart A.

Section 113 of the Act provides you with the opportunity to request a conference with us to discuss the violations alleged in the FOV/NOV. This conference will provide you a chance to present information on the identified violations, any efforts you have taken to comply, and the steps you will take to prevent future violations. Please plan for the Facility's technical and management personnel to take part in these discussions. You may have an attorney represent and accompany you at this conference.

**Explanation of Violations**

1. The following Refinery NSPS requirements, Indiana SIP rules, and permit conditions are relevant to this FOV/NOV:

   a. Indiana SIP Rule 326 Indiana Administrative Code (IAC) 7-4.1-3(a)(17) limits emissions of $SO_2$ from the standby incinerator to 1.25 pounds per hour (lbs/hr).

   b. Indiana SIP Rule 326 IAC 2-1-03 governs the construction permit requirements. Condition D.3.6 of construction permit SSM 089-13846-00003, issued on June 27, 2001, and amended by AA 089-15525-00003 on April 15, 2002, requires that all sulfur pit emissions be treated, monitored, and included as part of the emissions of the sulfur recovery unit.

   c. On March 8, 1974, U.S. EPA promulgated the Refinery NSPS, and has amended it several times since then.

   d. The Refinery NSPS at 40 C.F.R. § 60.104(a)(2)(i) limits the concentration of $SO_2$ emissions from any affected sulfur recovery plant controlled with oxidation system or a reduction system followed by incineration to 250 parts per million (ppm) at zero percent excess air.

   e. The NSPS at 40 C.F.R. § 60.11(d) requires that owners or operators of affected facilities maintain good air pollution control practice for minimizing emissions.

2. Based on an evaluation of a report submitted to the U.S. EPA on November 22, 2006, that was required by a Consent Decree between the United States and BP entered on August 29, 2001, U.S. EPA has determined the following:

   a. On October 4, 2006, and between October 30, 2006, and November 7, 2006, emissions from the Claus sulfur recovery plant were routed directly to the standby incinerator and not controlled in either of BP Whiting's tail gas units. The concentration of sulfur in these emissions was such that emissions from their incineration exceeded 250 ppm at zero percent excess air and 1.25 lbs/hr.

b. From October 30, 2006, until November 16, 2006, emissions from the sulfur pit were not controlled with the sulfur recovery unit. This resulted in a release of 2.2 tons of uncontrolled $H_2S$ emissions from the sulfur pit to the atmosphere.

3. BP Whiting's excess $SO_2$ emissions from the Claus sulfur recovery plant is a violation the $SO_2$ limit in the Refinery NSPS at 40 C.F.R. § 60.104(a)(2)(i).

4. BP Whiting's excess $SO_2$ emissions from the standby incinerator are violations of the $SO_2$ limit in the Indiana SIP at 326 IAC 7-4.1-3(a)(17).

5. BP Whiting's failure to treat emissions from the sulfur pit with the emissions from the sulfur recovery unit is a violation of condition D.3.6. of permit SSM 089-13846-00003, as amended by AA 089-15525-00003.

6. BP Whiting's failure to operate and maintain its sulfur recovery plant consistent with good air pollution control practice is a violation of 40 C.F.R. § 60.11(d).

**Environmental Impact of Violations**

7. Violation of the $SO_2$ standards increases the amount of acid rain and public exposure to unhealthy levels of $SO_2$. $SO_2$ reacts with other chemicals in the air to form tiny sulfate particles. Long term exposure to high levels of $SO_2$ gas and particles can cause respiratory illness, aggravate existing heart disease, and lead to premature death.

8. Violation of the requirements preventing $H_2S$ emissions increases the public's exposure to this toxic gas. Severe injury and death have been observed with short-term exposures to $H_2S$ levels exceeding 100 ppm. Acute exposures to elevated levels of $H_2S$ can result in pulmonary edema and central

nervous system effects including dizziness, nausea, headache and physical collapse.

1/25/2007

Date

Stephen Rothblatt, Director
Air and Radiation Division

**CERTIFICATE OF MAILING**

I, Loretta Shaffer, certify that I sent a Finding of Violation and Notice of Violation, No. EPA-5-07-IN-03, by Certified Mail, Return Receipt Requested, to:

Daniel Sajkowski, Business Unit Leader
BP Products North America, Inc.
2815 Indianapolis Boulevard
Whiting, Indiana 46394

I also certify that I sent copies of the Finding of Violation and Notice of Violation by first class mail to:

David McIver, Chief
Office of Enforcement Air Section
Indiana Department of Environmental Management
100 North Senate Avenue, Room 1001
Indianapolis, Indiana 46206-6015

on the 26 day of January, 2007.

CERTIFIED MAIL RECEIPT NUMBER: 7001 0320 0005 8919 2393

**U.S. ENVIRONMENTAL PROTECTION AGENCY**
**REGION 5**

| | | |
|---|---|---|
| **IN THE MATTER OF:** | ) | |
| | ) | |
| BP Products North America | ) | **NOTICE OF VIOLATION and** |
| Whiting, Indiana | ) | **FINDING OF VIOLATION** |
| | ) | |
| | ) | **EPA-5-08-IN-01** |
| Proceedings Pursuant to | ) | |
| the Clean Air Act, | ) | |
| 42 U.S.C. §§ 7401 et seq. | ) | |

**NOTICE AND FINDING OF VIOLATION**

BP Products North America, Inc. (BP or you) owns and operates a petroleum refinery at 2815 Indianapolis Boulevard, Whiting, Indiana (BP Whiting). The refinery consists of a number of pieces of equipment that generate air pollution and are subject to provisions of the Clean Air Act (the Act). This includes a fluidized catalytic cracking unit, sulfur recovery plant, a catalytic reforming unit, a catalytic refining unit, a catalytic feed hydrotreating unit, and several flares.

The U.S. Environmental Protection Agency (EPA) is sending this Notice of Violation and Finding of Violation (NOV/FOV or Notice) to notify you of several items. We find that you constructed a major modification causing a significant increase in nitrogen oxides ($NO_x$), sulfur dioxide ($SO_2$), carbon monoxide (CO), particulate matter less than 10 microns ($PM_{10}$) emissions at a major stationary source in an area that was designated as non-attainment for ozone and $SO_2$[1] and attainment for CO, $PM_{10}$, and nitrogen dioxide ($NO_2$) at the time of the modification, without first obtaining a construction permit meeting the New Source Review (NSR) and Prevention of Significant Deterioration (PSD) requirements in the Indiana State Implementation Plan (SIP). We find that you modified or constructed emission units making them affected facilities subject to emission limits and monitoring requirements in the New Source Performance Standards (NSPS) that apply to petroleum refineries but that you have yet to fully comply with the applicable monitoring requirements and have

[1] 1 Lake County was non-attainment for the $SO_2$ until September 26, 2005. 70 Fed. Reg. 56129.

failed to demonstrate continuous compliance with the applicable emission limits in the NSPS. We find that you failed to conduct a timely performance test demonstrating compliance with an emission limit for hydrogen chloride (HCl) located in the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II), 40 C.F.R. Part 63 Subpart UUU. Finally, we find that you have failed to comply with Title V requirements by not incorporating all applicable regulations into your Title V operating permit. All of these violations constitute violations of the Clean Air Act (the Act or CAA).

Section 113 of the Act provides you with the opportunity to request a conference with us to discuss the violations alleged in the NOV/FOV. This conference will provide you a chance to present information on the identified violations, any efforts you have taken to comply, and the steps you will take to prevent future violations. Please plan for the facility's technical and management personnel to take part in these discussions. You may have an attorney represent and accompany you at this conference.

**Regulatory Background**

1. The following provisions of the Indiana SIP are relevant to this NOV/FOV:

Construction Permit

a. Indiana SIP Rule 326 Indiana Administrative Code (IAC) 2-1-03(a) prohibits any person from commencing construction or modification of any air pollution source without first applying for and obtaining a construction permit from the commissioner of the Indiana Department of Environmental Management (IDEM).

b. Indiana SIP Rule 326 IAC 2-1-03(c) requires any person proposing the construction or modification of a major stationary PSD source or major PSD modification, which is or which will be located in an attainment area or unclassified area, to comply with the requirements of Indiana SIP Rule 326 IAC 2-2.

c. Indiana SIP Rule 326 IAC 2-1-03(d) requires any person proposing the construction or modification of a major source or facility, which will be located in a nonattainment area, to comply with the requirements of Indiana SIP Rule 326 IAC 2-3.

Attainment PSD

d. Indiana SIP Rule 326 IAC 2-2-2 states that new or modified major stationary sources or major modifications, constructed in an area designated in as attainment for a pollutant for which the stationary source or modification is major, are subject to 326 IAC 2-2, which contains the PSD provisions of the Indiana SIP.

e. Indiana SIP Rule 326 IAC 2-2-1(gg) defines "major stationary source" in an attainment area as a petroleum refinery that emits, or has the potential to emit 100 tons per year or more of any regulated NSR pollutant.

f. Indiana SIP Rule 326 IAC 2-2-1(ee) defines "major modification" as any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase.

g. Indiana SIP Rule 326 IAC 2-2-1(jj) defines "net emissions increase" as the amount by which the sum of the increase in emissions from a physical change or change in the method of operation and any other contemporaneous increases or decreases in emissions exceeds zero.

h. In reference to CO, Indiana SIP Rule 326 IAC 2-2-1(xx) defines "significant" with regard to a net emissions increase as rate of emissions that would equal or exceed 100 tons per year.

i. In reference to $PM_{10}$, Indiana SIP Rule 326 IAC 2-2-1(xx) defines "significant" with regard to a net emissions increase as rate of emissions that would equal or exceed 15 tons per year.

j. In reference to $NO_x$, Indiana SIP Rule 326 IAC 2-2-1(xx) defines "significant" with regard to a net emissions increase as rate of emissions that would equal or exceed 40 tons per year.

k. Indiana SIP Rule 326 IAC 2-2-3(2) requires that owners or operators making a major modification apply best available control technology (BACT) for each regulated pollutant for which the modification would result in a significant net emissions increase.

l. Indiana SIP Rule 326 IAC 2-2-1(i) defines "BACT" as an emissions limitation based on the maximum degree of reduction for each regulated NSR pollutant that would be emitted from any proposed major modification.

m. Indiana SIP Rule 326 IAC 2-2-5 requires that owners or operators of a proposed major modification demonstrate that allowable emissions increases in conjunction with all other applicable emission increases or reductions will not cause or contribute to air pollution in violation of any ambient air quality standard or applicable maximum allowable increase over the baseline concentration in any area.

Non-attainment NSR

n. Indiana SIP Rule 326 IAC 2-3-2(a) states that new or modified major stationary sources or major modifications, constructed in an area designated in as non-attainment for a pollutant for which the stationary source or modification is major, are subject to 326 IAC 2-3, which contains the non-attainment NSR provisions of the Indiana SIP.

o. Indiana SIP Rule 326 IAC 2-3-1(aa)(1) defines a "major stationary source" as any stationary source of air pollutants which emits, or has the potential to emit, one hundred (100) tons per year or more of any air pollutant subject to regulation under the Clean Air Act.

p. Indiana SIP Rule 326 IAC 2-3-1(z) defines "major modification" as any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase.

q. Indiana SIP Rule 326 IAC 2-3-1(dd) defines "net emissions increase" as the amount by which the sum of the increase in emissions from a physical change or change in the mechod of operation and any other contemporaneous increases or decreases in emissions exceeds zero.

r. In reference to $NO_x$, Indiana SIP Rule 326 IAC 2-3-1(qq) defines "significant" with regard to a net emissions increase as rate of emissions that would equal or exceed 40 tons per year.

s. In reference to $SO_2$, Indiana SIP Rule 326 IAC 2-3-1(qq) defines "significant" with regard to a net emissions increase as rate of emissions that would equal or exceed 40 tons per year.

t. Indiana SIP Rule 326 IAC 2-3-3(a)(2) requires that, prior to the issuance of a construction permit, the applicant must apply emission limitation devices or techniques to the proposed construction or modification such that it achieves the Lowest Achievable Emission Rate (LAER) for the applicable pollutant.

u. Indiana SIP Rule 326 IAC 2-3-1(y) defines "LAER" as the more stringent rate of emissions based on the most stringent emissions limitation for that particular source contained in the implementation plan of any state or achieved in practice.

v. Indiana SIP Rule 326 IAC 2-3-3(a)(5) requires that emissions resulting from the proposed construction or modification be offset by a reduction in actual emissions of the same pollutant from an existing source or combination of existing sources.

w. Indiana SIP Rule 326 IAC 2-3-3(a)(7) states that the applicant must obtain the necessary preconstruction approvals and must meet all the permit requirements specified in Indiana SIP rule 326 IAC 2-1.

2. The following NSPS provisions are relevant to this NOV/FOV:

General Provisions

a. The NSPS General Provisions at 40 C.F.R. § 60.2 define "modification" as any physical change in, or change in the method of operation of, an existing facility which increases the emission rate of any air pollutant to which a standard applies to the atmosphere.

b. The NSPS General Provisions at 40 C.F.R. § 60.8(a) require owners or operators of facilities subject to NSPS standards to conduct a performance test to demonstrate compliance with the applicable standard no later than 180 days after the initial startup of the affected facility.

Fuel Gas Combustion Devices

c. The NSPS for Petroleum Refineries at 40 C.F.R. § 60.100(b) state that any fuel gas combustion device which commences construction or modification after June 11, 1973, is subject to the NSPS for Petroleum Refineries.

d. The NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(1) prohibit owners or operators from burning in any fuel gas combustion device subject to these provisions any fuel gas that contains hydrogen sulfide ($H_2S$) in excess of 230 milligrams per dry standard cubic meter (mg/dscm).

e. The NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(3) require owners or operators of fuel gas combustion devices subject to 40 C.F.R. § 104(a)(1) to install, calibrate, operate, and maintain an instrument for continuously monitoring and recording the concentration by volume of $SO_2$ emissions into the atmosphere.

f. The NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(4) allow owners or operators to install, calibrate, operate, and maintain an instrument for continuously monitoring and recording the concentration of $H_2S$ in fuel gases before being burned in a subject fuel gas combustion device.

Sulfur Recovery Plants

g. The NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(2)(i) prohibit owners or operators from discharging any gases into the atmosphere from any subject Claus sulfur recovery plant containing in excess of 250 parts per million by volume (ppmV) of $SO_2$ at zero percent excess air when the Claus sulfur recovery plant is controlled by an oxidation system or a reduction system followed by an oxidation system.

h. The NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(2)(ii) prohibit owners or operators from discharging any gases into the atmosphere from any subject Claus sulfur recovery plant containing in excess of 300 ppmV of reduced sulfur compounds and 10 ppmV of $H_2S$ at zero percent excess air when the Claus sulfur recovery plant is controlled by a reduction system not followed by incineration.

i. The NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(5) require owners or operators of Claus sulfur recovery plants subject to 40 C.F.R. § 104(a)(2)(i) to install, calibrate, operate, and maintain instruments for continuously monitoring and recording the concentration by volume of $SO_2$ and oxygen ($O_2$) emissions into the atmosphere.

j. The NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(6) require owners or operators of Claus sulfur recovery plants subject to 40 C.F.R. § 104(a)(2)(ii) to install, calibrate, operate, and maintain instruments for continuously monitoring and recording the concentration by volume of reduced sulfur compound and $O_2$ emissions into the atmosphere.

3. The following Refinery MACT II provisions are relevant to this NOV/FOV:

a. Refinery MACT II at 40 C.F.R. § 63.1567(a)(1) requires owners or operators of catalytic reforming units to comply with each applicable limit for inorganic HAP emissions located in Table 22 of Refinery MACT II.

b. Refinery MACT II at Table 22 requires owners or operators of cyclic catalytic reforming units to either meet a 97 percent HCl removal efficiency or a 10 ppmV outlet concentration, corrected to 3 percent oxygen.

c. Refinery MACT II at 40 C.F.R. §§ 63.1563 and 63.1571 requires owners or operators subject to Refinery MACT

II to conduct performance tests and report the results by no later than 150 days after April 11, 2005.

d. Refinery MACT II at Table 25 1(e)(1) requires that for semi-regenerative and cyclic regeneration units, the test required by 40 C.F.R. § 63.1571 be conducted during the coke burn-off and catalyst rejuvenation cycle.

4. The following Title V provisions and underlying requirements located at 40 C.F.R. Part 70 are relevant to this NOV/FOV:

a. Title V of the CAA establishes an operating permit program for major sources. The purpose of Title V is to ensure that all "applicable requirements" for compliance with the CAA, including SIP and NSPS requirements, are collected in one place.

b. Title V requires that each permit issued under this program include enforceable emission limitations and such other conditions as are necessary to assure compliance with "applicable requirements" of the CAA, including the requirements of the applicable SIP.

c. Under Title V, any owner or operator of a source subject to the Title V program is required to submit a timely and complete permit application that contains information sufficient to determine the applicability of any CAA requirements, certifies compliance with all applicable requirements, and contains a compliance plan for all applicable requirements for which the source is not in compliance.

d. Under Title V, any applicant who fails to submit any relevant fact or who has submitted incorrect information in a permit application is required to promptly submit such supplementary facts or corrected information upon becoming aware of such failure or incorrect submittal.

e. Title V program requirements are codified at Section 503 of the CAA, 42 U.S.C. § 7661b with implementing regulations at 40 C.F.R. Part 70.

**Explanation of Violations**

FCU 500

1. BP Whiting has the potential to emit several regulated NSR pollutants in excess of 100 tons per year, making it a major stationary source.

2. In February 2005, BP Whiting constructed a project on its fluidized catalytic cracking unit designated as FCU 500. This project included combustion air improvements, a reactor stripper revamp, a slurry system reliability upgrade, and a feed nozzle replacement.

3. The February 2005 project constructed on FCU 500 constitutes a modification to an air pollution source.

4. BP Whiting failed to obtain any permits, conduct any modeling, or undergo any other sort of pre-construction review for this modification.

5. BP Whiting failed to obtain a construction permit for this modification, in violation of Indiana SIP Rule 326 IAC 2-1-03(a).

6. The February 2005 project allows BP to increase the feed rate to FCU 500 in a manner that would increase emissions of $NO_x$, $SO_2$, CO, and $PM_{10}$ by significant amounts, thus making the project a major modification.

7. BP Whiting is located in Lake County, Indiana. In February 2005, Lake County, Indiana was listed as attainment or unclassifiable for CO, $PM_{10}$, and $NO_2$ and as non-attainment for $SO_2$ and ozone.

8. Because a $NO_x$ waiver did not apply to the ozone standard for which Lake County was non-attainment and $NO_x$ is a pre-cursor for ozone, the non-attainment provisions of the Indiana SIP apply to major modifications with significant $NO_x$ emission increases.

9. Because $NO_x$ also contributes to ambient levels of $NO_2$ and Lake County, Indiana is attainment for $NO_2$, the PSD provisions of the Indiana SIP also apply to major modifications with significant $NO_x$ emissions increases.

10. With regard to CO, $PM_{10}$, and NO2 BP Whiting's failure to obtain a permit for this major modification meeting the PSD requirements in Indiana SIP Rule 326 IAC 2-2 is a violation of Indiana SIP Rule 326 IAC 2-1-03(c).

11. BP Whiting's failure to apply BACT to control emissions of CO, $PM_{10}$, and $NO_x$ is a continuing violation of Indiana SIP Rule 326 ICA 2-2-3(2).

12. BP Whiting's failure to demonstrate that allowable emissions increases from this major modification will not cause or contribute to air pollution in violation of any ambient air quality standard or applicable maximum allowable increase over the baseline concentration in any area is a violation of Indiana SIP Rule 326 IAC 2-2-5.

13. With regard to $SO_2$ and $NO_x$, BP Whiting's failure to obtain a permit for this major modification meeting the nonattainment NSR requirements in Indiana SIP Rule 326 IAC 2-3 is a violation of Indiana SIP Rule 326 IAC 2-1-03(d).

14. BP Whiting's failure to apply controls achieving LAER for emissions of $SO_2$ and $NO_x$ is a continuing violation of Indiana SIP Rule 326 ICA 2-3-3(a)(2).

15. BP Whiting's failure to offset emissions resulting from this major modification by reducing actual emissions of $NO_x$ and $SO_2$ from an existing source or combination of existing sources is a violation of Indiana SIP Rule 326 IAC 2-3-3(a)(5).

<u>Fuel Gas Combustion Devices</u>

16. On October 5, 1988, BP Whiting increased the size of the knockout drum for its UIU Flare, thus increasing the capacity of the flare.

17. On October 15, 1989, BP Whiting increased the size of the knockout drum for its Alky Flare, thus increasing the capacity of the flare.

18. These projects to increase the capacity of the UIU and Alky Flares constitute modifications under the NSPS for Petroleum Refineries, making both of these fuel gas combustion devices subject to requirements in this rule.

19. BP Whiting has not installed instruments to continuously monitor the emissions of $SO_2$ into the atmosphere from these flares or instruments to monitor the $H_2S$ concentration of the fuel gas combusted in these flares, in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(3) or 40 C.F.R. § 60.105(a)(4).

20. BP Whiting has not conducted performance tests on the fuel gas combusted in the UIU or Alky Flares to demonstrate compliance with the $H_2S$ concentration limit in 40 C.F.R. § 60.104(a)(1), in violation of the NSPS General Provisions at 40 C.F.R. § 60.8(a).

21. BP Whiting installed the DDU Flare in 1993, making it subject to the NSPS for Petroleum Refineries.

22. BP Whiting did not install an instrument to continuously monitor the H2S concentration of the fuel gas combusted in the DDU Flare until January 15, 2005, in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(4).

23. BP Whiting did not conduct a performance test on the fuel gas combusted in the DDU Flare to demonstrate compliance with the $H_2S$ concentration limit at 40 C.F.R. § 60.104(a)(1) until January 15, 2005, in violation of the NSPS General Provisions at 40 C.F.R. § 60.8(a).

24. BP Whiting installed the LPG Flare in 1986, making it subject to the NSPS for Petroleum Refineries.

25. On January 25, 2005, BP Whiting received approval for an alternative monitoring plan that allowed BP Whiting to avoid installing an instrument to continuously monitor $H_2S$ in the fuel gas combusted in the LPG flare or $SO_2$ emissions from the LPG flare. Until this alternative monitoring plan was approved, BP Whiting was in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(3) or 40 C.F.R. § 60.105(a)(4).

26. BP Whiting has not conducted a performance test on the fuel gas combusted in the LPG Flare to demonstrate compliance with the $H_2S$ concentration limit at 40 C.F.R. § 60.104(a)(1), in violation of the NSPS General Provisions at 40 C.F.R. § 60.8(a).

27. BP Whiting owns and operates a catalytic feed hydrotreating

unit, a catalytic refining unit, a sulfur recover plant mix drum, and catalytic reforming unit (Ultraformer 4) that combust fuel gas and are also subject to the $H_2S$ in fuel gas concentration limit in the NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(1).

28. BP Whiting is required to continuously monitor and record the concentration of $H_2S$ in the fuel gas combusted in the DDU Flare, the catalytic feed hyrdotreating unit, the catalytic refining unit, the sulfur recovery plant mix drum, and Ultraformer 4.

29. On numerous occasions in the past five or more years, BP Whiting has recorded exceedances of the 230 mg/dscm $H_2S$ concentration limit in the fuel gas combusted in the DDU Flare, the catalytic feed hydrotreating unit, the catalytic refining unit, the sulfur recover plant mix drum, and Ultraformer 4 in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(1).

30. On numerous occasions in the past five or more years, BP Whiting has failed to monitor the $H_2S$ concentration in fuel gas combusted in the DDU Flare, the catalytic feed hydrotreating unit, that catalytic refining unit, the sulfur recover plant mix drum, and Ultraformer 4, in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(4).

Sulfur Recovery Plant

31. BP Whiting owns and operates a sulfur recovery plant that at times is controlled with an oxidation system or a reduction system followed by oxidation. During those times, the emissions from the sulfur recovery plant are subject to the $SO_2$ emission standard in the NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(2)(i).

32. BP Whiting owns and operates a sulfur recovery plant that at times is controlled with a reduction system not followed by oxidation. During those times, the emissions from the sulfur recovery plant are subject to the reduced sulfur emission standard in the NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(2)(ii).

33. BP Whiting is required to continuously monitor and record the emissions of $SO_2$ from its sulfur recovery plant when it

is controlled by an oxidation system or a reduction system followed by oxidation and reduced sulfur compound emissions when it is controlled by a reduction system not followed by oxidation..

34. On numerous occasions in the past five or more years, BP Whiting has recorded exceedances of the 250 ppmV $SO_2$ emission limit when the sulfur recovery plant was controlled with an oxidation system or reduction system followed by oxidation, in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(2)(i).

35. On numerous occasions in the past five or more years, BP Whiting has failed to monitor and record $SO_2$ emissions when the sulfur recovery plant was controlled with an oxidation system or reduction system followed by oxidation, in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(5).

36. On numerous occasions in the past five or more years, BP Whiting has recorded exceedances of the 300 ppmV reduced sulfur compound emission limit when the sulfur recovery plant was controlled with a reduction system not followed by oxidation, in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.104(a)(2)(ii).

37. On numerous occasions in the past five or more years, BP Whiting has failed to monitor and record reduced sulfur compound emissions when the sulfur recovery plant was controlled with a reduction system not followed by oxidation, in violation of the NSPS for Petroleum Refineries at 40 C.F.R. § 60.105(a)(6).

Ultraformers

38. After the compliance date of Refinery MACT II, BP Whiting has operated Ultraformers 3 and 4, which are catalytic reforming units subject to an inorganic HAP emission limit in Table 22 of Refinery MACT II.

39. BP Whiting chose to comply with the 10 ppmV HCl concentration limit located in Table 22 of Refinery MACT II.

40. BP Whiting failed to conduct performance testing and submit the results of the HCl emissions from Ultraformers 3 and 4

during both coke burn-off and catalyst rejuvenation cycle within 150 days of April 11, 2005, in violation of Refinery MACT II at 40 C.F.R. § 63.1571.

Title V

41. BP Whiting continuously violates Title V permitting requirements at Section 503 of the CAA and 40 C.F.R. Part 70, because it has yet to submit a complete application for a Title V operating permit for the Facility that identifies all applicable requirements, that accurately certifies compliance with such requirements, and that contains a compliance plan for all applicable requirements for which it is not in compliance.

**Environmental Impact of Violations**

1. Excess emissions of $NO_x$ increase ground level concentrations of ozone and nitrogen dioxide, both of which can cause respiratory inflammation, increased difficulty breathing, and lung damage. NOx emissions also contribute to acid rain, global warming, the formation of fine particles in the atmosphere, water quality deterioration, and visibility impairment.

2. Excess emissions of $SO_2$ increase the amount of acid rain and public exposure to unhealthy levels of $SO_2$. $SO_2$ reacts with other chemicals in the air to form tiny sulfate particles. Long term exposure to high levels of $SO_2$ gas and particles can cause respiratory illness, aggravate existing heart disease, and lead to premature death.

3. Excess emissions of CO increase public exposure to CO, which can enter the bloodstream reducing oxygen delivery and can aggravate cardiovascular disease.

4. Excess emissions of $PM_{10}$ increase public exposure to unhealthy fine particulate matter. Fine particulate matter contributes to respiratory problems, lung damage, and premature deaths.

5. Violations of HAP standards may cause serious health effects including birth defects and cancer. HAPs may also cause harmful environmental and ecological effects.

11/29/07
Date

Stephen Rothblatt, Director
Air and Radiation Division

**CERTIFICATE OF MAILING**

I, Loretta Shaffer, certify that I sent a Notice and Finding of Violation, No. EPA-5-08-IN-01 , by Certified Mail, Return Receipt Requested, to:

Daniel Sajkowski, Business Unit Leader
BP Products North America, Inc.
2815 Indianapolis Boulevard
Whiting, Indiana 46394

I also certify that I sent copies of the Finding of Violation and Notice of Violation by first class mail to:

Craig Henry, Chief
Office of Enforcement Air Section
Indiana Department of Environmental Management
100 North Senate Avenue, Room 1001
Indianapolis, Indiana 46206-6015

on the 29th day of November, 2007.

Betty Williams
Betty Williams, Secretary
AECAS, (IL/IN)

CERTIFIED MAIL RECEIPT NUMBER: Hand Delivered

U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 5

| | | |
|---|---|---|
| IN THE MATTER OF: | ) | |
| | ) | AMENDMENT TO |
| BP Products North America | ) | NOTICE OF VIOLATION AND |
| Whiting, Indiana | ) | FINDING OF VIOLATION |
| | ) | EPA-5-08-IN-01 |
| Proceedings Pursuant to the Clean Air Act, | ) | |
| 42 U.S.C. § 7401 *et seq.* | ) | |

AMENDMENT TO NOTICE OF VIOLATION AND FINDING OF VIOLATION

BP Products North America, Inc. (BP or you) owns and operates a petroleum refinery at 2815 Indianapolis Boulevard, Whiting, Indiana (BP Whiting). The refinery consists of a number of pieces of equipment that generate air pollution and are subject to provisions of the Clean Air Act (the Act or CAA).

The U.S. Environmental Protection Agency is sending this Amendment to the Notice of Violation and Finding of Violation (Amendment to NOV/FOV or Notice) issued to you on November 29, 2007, to notify you that we allege that you constructed a major modification causing a significant increase in nitrogen oxides ($NO_x$), sulfur dioxide ($SO_2$), carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns ($PM_{10}$) emissions at a major stationary source in an area that was designated as nonattainment for ozone and $SO_2$[1] and attainment for CO, PM, $PM_{10}$, and nitrogen dioxide ($NO_2$) at the time of the modification, without first obtaining a construction permit meeting the New Source Review (NSR) and Prevention of Significant Deterioration (PSD) requirements in the Indiana State Implementation Plan (SIP). Further, we find that you have failed to comply with Title V requirements by not incorporating all applicable requirements into your Title V operating permit. All of these violations constitute violations of the Act.

Section 113 of the Act provides you with the opportunity to request a conference with us to discuss the violations alleged in the NOV/FOV. This conference will provide you with the opportunity to present information on the identified violations, any efforts you have taken to comply, and the steps you will take to prevent future violations. Please plan for the facility's technical and management personnel to take part in these discussions. You may have an attorney represent and accompany you at this conference.

[1] Lake County was non-attainment for $SO_2$ until September 26, 2005. 70 Fed. Reg. 56129.

**Regulatory Background**

1. The following provisions of the Indiana SIP are relevant to this Amendment to the NOV/FOV:

Construction Permit

a. Indiana SIP Rule 326 Indiana Administrative Code (IAC) 2-1-03(a) prohibits any person from commencing construction or modifying any air pollution source without first applying for and obtaining a construction permit from the commissioner of the Indiana Department of Environmental Management (IDEM).

b. Indiana SIP Rule 326 IAC 2-1-03(c) requires any person proposing the construction or modification of a major stationary PSD source or major PSD modification, which is or which will be located in an attainment area or unclassified area, to comply with the requirements of Indiana SIP Rule 326 IAC 2-2.

c. Indiana SIP Rule 326 IAC 2-1-03(d) requires any person proposing the construction or modification of a major source or facility, which will be located in a nonattainment area, to comply with the requirements of Indiana SIP Rule 326 IAC 2-3.

Attainment PSD

d. Indiana SIP Rule 326 IAC 2-2-2 states that new or modified major stationary sources or major modifications, constructed in an area designated as in attainment for a pollutant for which the stationary source or modification is major, are subject to 326 IAC 2-2, which contains the PSD provisions of the Indiana SIP.

e. Indiana SIP Rule 326 IAC 2-2-l(gg)(1)(K) defines "major stationary source" in an attainment area as a petroleum refinery that emits, or has the potential to emit 100 tons per year or more of any regulated NSR pollutant.

f. Indiana SIP Rule 326 IAC 2-2-l(ee) defines "major modification" as any physical change or change in the method of operation of a major stationary source that would result in a significant emissions increase.

g. Indiana SIP Rule 326 IAC 2-2-l(jj) defines "net emissions increase" as the amount by which the sum of the increase in emissions from a physical change or change in the method of operation and any other contemporaneous increases or decreases in emissions exceeds zero.

h. In reference to CO, Indiana SIP Rule 326 IAC 2-2-l(xx) defines "significant" with regard to a net emissions increase as the rate of emissions that would equal or exceed 100 tons per year.

i. In reference to PM, Indiana SIP Rule 326 IAC 2-2-l(xx) defines "significant" with regard to a net emissions increase as rate of emissions that would equal or exceed 25 tons per year.

j. In reference to $PM_{10}$, Indiana SIP Rule 326 IAC 2-2-l(xx) defines "significant" with regard to a net emissions increase as the rate of emissions that would equal or exceed 15 tons per year.

k. In reference to $NO_x$, Indiana SIP Rule 326 IAC 2-2-l(xx) defines "significant" with regard to a net emissions increase as the rate of emissions that would equal or exceed 40 tons per year.

l. Indiana SIP Rule 326 IAC 2-2-3(2) requires that owners or operators making a major modification apply best available control technology (BACT) for each regulated pollutant for which the modification would result in a significant net emissions increase.

m. Indiana SIP Rule 326 IAC 2-2-1(i) defines "BACT" as an emissions limitation based on the maximum degree of reduction for each regulated NSR pollutant that would be emitted from any proposed major modification.

n. Indiana SIP Rule 326 IAC 2-2-5 requires that owners or operators of a proposed major modification demonstrate that allowable emission increases in conjunction with all other applicable emission increases or reductions will not cause or contribute to air pollution in violation of any ambient air quality standard or applicable maximum allowable increase over the baseline concentration in any area.

Non-attainment NSR

o. Indiana SIP Rule 326 IAC 2-3-2(a) states that new or modified major stationary sources or major modifications, constructed in an area designated as in non-attainment for a pollutant for which the stationary source or modification is major, are subject to 326 IAC 2-3, which contains the nonattainment NSR provisions of the Indiana SIP.

p. Indiana SIP Rule 326 IAC 2-3-l(aa) (1) defines a "major stationary source" as any stationary source of air pollutants which emits, or has the potential to emit, one hundred (100) tons per year or more of any air pollutant subject to regulation under the Clean Air Act.

q. Indiana SIP Rule 326 IAC 2-3-1(z) defines "major modification" as any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase.

r. Indiana SIP Rule 326 IAC 2-3-1(dd) defines "net emissions increase" as the amount by which the sum of the increase in emissions from a physical change or change in the method of operation and any other contemporaneous increases or decreases in emissions exceeds zero.

s. In reference to $NO_x$, Indiana SIP Rule 326 IAC 2-3-l(qq) defines "significant" with regard to a net emissions increase as the rate of emissions that would equal or exceed 40 tons per year.

t. In reference to $SO_2$, Indiana SIP Rule 326 IAC 2-3-l(qq) defines "significant" with regard to a net emissions increase as the rate of emissions that would equal or exceed 40 tons per year.

u. Indiana SIP Rule 326 IAC 2-3-3(a) (2) requires that, prior to the issuance of a construction permit, the applicant must apply emission limitation devices or techniques to the proposed construction or modification such that it achieves the Lowest Achievable Emission Rate (LAER) for the applicable pollutant.

v. Indiana SIP Rule 326 IAC 2-3-1(y) defines "LAER" as the more stringent rate of emissions based on the most stringent emissions limitation for that particular source contained in the implementation plan of any state or achieved in practice.

w. Indiana SIP Rule 326 IAC 2-3-3(a) (5) requires that emissions resulting from the proposed construction or modification be offset by a reduction in actual emissions of the same pollutant from an existing source or combination of existing sources.

x. Indiana SIP Rule 326 IAC 2-3-3(a) (7) states that the applicant must obtain the necessary preconstruction approvals and must meet all the permit requirements specified in Indiana SIP rule 326 IAC 2-1.

2. The following Title V provisions and underlying requirements located at 40 C.F.R. Part 70 are relevant to this Amendment to the NOV/FOV:

a. Title V of the CAA establishes an operating permit program for major sources. The purpose of Title V is to ensure that all "applicable requirements" for compliance with the CAA are collected in one place.

b. Title V requires that each permit issued under this program include enforceable emission limitations and such other conditions as are necessary to assure compliance with "applicable requirements" of the CAA, including the requirements of the applicable SIP.

c. Under Title V, any owner or operator of a source subject to the Title V program is required to submit a timely and complete permit application that contains information sufficient to determine the applicability of any CAA requirements, certifies compliance with all applicable requirements, and contains a compliance plan for all applicable requirements for which the source is not in compliance.

d. Under Title V, any applicant who fails to submit any relevant fact or who has submitted incorrect information in a permit application is required to promptly submit such supplementary facts or corrected information upon becoming aware of such failure or incorrect submittal.

e. Title V program requirements are codified at Section 503 of the CAA, 42 U.S.C. § 766lb with implementing regulations at 40 C.F.R. Part 70.

**Explanation of Violations**

1. BP Whiting has the potential to emit several regulated NSR pollutants in excess of 100 tons per year, making it a major stationary source.

2. Beginning in early 2005, BP Whiting performed a turnaround (TAR) at its fluidized catalytic cracking unit designated as FCU 500, as well as other projects at associated units.

3. Certain projects performed at the refinery, including but not limited to projects related to the 2005 TAR, allowed BP to commence construction of its Canadian crude expansion project. These projects constitute a major modification to an air pollution source without an appropriate permit.

4. The commencement of construction of this major modification allows BP to, among other things, process feed derived from Canadian crude in a manner that could increase emissions of $NO_x$, $SO_2$, CO, PM, and $PM_{10}$ by significant amounts at the units specified in Appendix A.

5. BP Whiting failed to obtain any permits, conduct any modeling, install BACT, or undergo any other sort of pre-construction review for this modification.

6. BP Whiting failed to obtain a construction permit for this modification, in violation of Indiana SIP Rule 326 IAC 2-1-03(a).

7. BP Whiting is located in Lake County, Indiana. In February 2005, Lake County, Indiana was listed as attainment or unclassifiable for CO, PM, $PM_{10}$, and $NO_2$ and as non-attainment for $SO_2$ and ozone.

8. Because a $NO_x$ waiver did not apply to the ozone standard for which Lake County was in non-attainment, and $NO_x$ is a pre-cursor for ozone, the non-attainment provisions of the Indiana SIP apply to major modifications with significant $NO_x$ emission increases.

9. Because $NO_x$ also contributes to ambient levels of $NO_2$ and Lake County, Indiana is in attainment for $NO_2$, the PSD provisions of the Indiana SIP also apply to major modifications with significant $NO_x$ emissions increases.

10. With regard to CO, PM, $PM_{10}$, and $NO_x$, BP Whiting's failure to obtain a permit for this major modification meeting the PSD requirements in Indiana SIP Rule 326 IAC 2-2 is a violation of Indiana SIP Rule 326 IAC 2-1-03(c).

11. BP Whiting's failure to apply BACT on the units specified in Appendix A to control emissions of CO, PM, $PM_{10}$, and $NO_x$ is a continuing violation of Indiana SIP Rule 326 IAC 2-2-3(2).

12. BP Whiting's failure to demonstrate that allowable emission increases from this major modification will not cause or contribute to air pollution in violation of any ambient air quality standard or applicable maximum allowable increase over the baseline concentration in any area is a violation of Indiana SIP Rule 326 IAC 2-2-5.

13. With regard to $SO_2$ and $NO_x$, BP Whiting's failure to obtain a permit for this major modification meeting the nonattainment NSR requirements in Indiana SIP Rule 326 IAC 2-3 is a violation of Indiana SIP Rule 326 IAC 2-1-03(d).

14. BP Whiting's failure to apply controls achieving LAER on the units specified in Appendix A for emissions of $SO_2$ and $NO_x$ is a continuing violation of Indiana SIP Rule 326 IAC 2-3-3(a) (2).

15. BP Whiting's failure to offset emissions resulting from this major modification by reducing actual emissions of $SO_2$ and $NO_x$ from an existing source or combination of existing sources is a violation of Indiana SIP Rule 326 IAC 2-3-3(a) (5).

<u>Title V</u>

16. BP Whiting is continuously violating Title V permitting requirements in Section 503 of the CAA and 40 C.F.R. Part 70, because it has yet to submit a complete application for a Title V operating permit for the Facility that identifies all applicable requirements, that accurately certifies compliance with such requirements, and that contains a compliance plan for all applicable requirements for which it is not in compliance.

**Environmental Impact of Violations**

1. Excess emissions of $NO_x$ increase ground level concentrations of ozone and nitrogen dioxide, both of which can cause respiratory inflammation, increased difficulty breathing, and lung damage. $NO_x$ emissions also contribute to acid rain, global warming, the formation of fine particles in the atmosphere, water quality deterioration, and visibility impairment.

2. Excess emissions of $SO_2$ increase the amount of acid rain and public exposure to unhealthy levels of $SO_2$. $SO_2$ reacts with other chemicals in the air to form tiny sulfate particles. Long term exposure to high levels of $SO_2$ gas and particles can cause respiratory illness, aggravate existing heart disease, and lead to premature death.

3. Excess emissions of CO increase public exposure to CO, which can enter the bloodstream reducing oxygen delivery and can aggravate cardiovascular disease.

4. Excess emissions of PM and $PM_{10}$ increase public exposure to unhealthy fine particulate matter. Fine particulate matter contributes to respiratory problems, lung damage, and premature deaths.

October 1, 2008
Date

Cheryl L. Newton
Acting Director
Air and Radiation Division

**<u>Appendix A</u>**

| Facility | Emissions Units/Description of Changes |
|---|---|
| No.11 pipestill | Installation of Ultra-low-$NO_x$ burners on H-200 |
| New Coker | New Coker, new heaters H-201, H-202, H-203, and VRU 400 |
| No. 12 pipe still | New heaters H-101A, H-101B, H-102 |
| Sulfur Recovery Unit | New COT1 and COT2 tail gas units, tanks SH-1 and SH-2; new trains D and E, and sulfur pits D and E |
| Isomerization Unit | Modified heater ISOM H-1 |
| Blending Oil Unit | Modified heater F-401 |
| Fluidized Catalytic Cracking Unit (FCU) 500 | 2005 Turnaround |
| FCU 600 | Modified unit |
| Marine dock facility | Installation of Vapor Recovery/Control Unit on gasoline loading |
| Hydrocarbon Flares | New flares South, GOHT |
| Distillate Hydrotreating Unit | New heater B-601A |
| New Gas Oil Hydrotreater | New heaters F-901Aand F-901B |
| New Hydrogen Unit | New heaters HU-1 and HU-2, HU flare and HU Cooling Tower |
| Cooling Towers | New cooling towers 7 and 8 |
| Boilers | New boilers 1 and 2 |
| Miscellaneous | Any other emission units physically changed that emit CO, $PM_{10}$, PM, $NO_x$, and $SO_2$ |

**CERTIFICATE OF MAILING**

I, Betty Williams, certify that I sent an Amendment to the Notice of Violation and Finding of Violation, No. EPA-5-08-IN-01, by Certified Mail, Return Receipt Requested, to:

Daniel Sajkowski, Business Unit Leader
BP Products North America, Inc.
2815 Indianapolis Boulevard
Whiting, Indiana 46394

I also certify that I sent copies of the Amendment to the Notice of Violation and Finding of Violation by first class mail to:

Craig Henry, Chief
Office of Enforcement Air Section
Indiana Department of Environmental Management
100 North Senate Avenue, Room 1001
Indianapolis, Indiana 46206-6015

and to:

William L. Patberg
Shumaker, Loop & Kendrick, LLP
1000 Jackson Street
Toledo, Ohio 43604-5573

on the 2nd day of October, 2008.

Betty Williams
Betty Williams, Secretary
AECAS, (IL/IN)

CERTIFIED MAIL RECEIPT NUMBER: 7001 0320 0006 0186 1603

**U.S. ENVIRONMENTAL PROTECTION AGENCY**
**REGION 5**

| | | |
|---|---|---|
| **IN THE MATTER OF:** | ) | |
| | ) | |
| BP Products North America, Inc. | ) | **NOTICE OF VIOLATION** |
| Whiting, Indiana | ) | |
| | ) | **EPA-5-09-IN-13** |
| | ) | |
| Proceedings Pursuant to | ) | |
| the Clean Air Act, | ) | |
| 42 U.S.C. §§ 7401 et seq. | ) | |

## NOTICE OF VIOLATION

The U.S. Environmental Protection Agency finds that BP Products North America, Inc. (BP or you) is violating Section 112 of the Clean Air Act (CAA), 42 U.S.C. § 7412, at its petroleum refinery, located at 2815 Indianapolis Boulevard in Whiting, Indiana (BP Whiting). Specifically, BP is violating the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Benzene Waste Operations at 40 C.F.R. Part 61, Subpart FF, as follows:

**Regulatory Background**

1. Pursuant to Section 112(d) of the CAA, on March 7, 1990, EPA promulgated the National Emission Standard for Benzene Waste Operations (Benzene Waste NESHAP) (55 Fed. Reg. 8292). These regulations are codified at 40 C.F.R. Part 61, Subpart FF, §§ 61.340 – 61.359. On March 5, 1992, EPA issued a stay of effectiveness of the Benzene Waste NESHAP and proposed clarifying amendments (57 Fed. Reg. 8012). On January 7, 1993, EPA promulgated the clarifying amendments to the Benzene Waste NESHAP and affected facilities were given 90 days to come into compliance with the regulations. 58 Fed. Reg. 3072.

2. 40 C.F.R. § 61.05(c) prohibits any owner or operator from operating an existing source in violation of an applicable NESHAP 90 days after the effective date of the standard, unless a waiver was granted by the Administrator pursuant to § 61.11, or unless an exemption was granted by the President under Section 112(c)(2) of the CAA.

3. According to 40 C.F.R. § 61.340(a), the Benzene Waste NESHAP applies to owners and operators of, among other sources, petroleum refineries. 40 C.F.R. § 61.341 defines "petroleum refinery" as any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

4. Facilities that are subject to the Benzene Waste NESHAP and have a total annual benzene quantity greater than or equal to 10 Mg/yr, as determined by the procedures outlined in 40 C.F.R. § 61.342(a), shall manage and treat facility waste in accordance with 40 C.F.R. § 61.342(c), (d), or (e).

5. Facilities that choose to comply with the compliance option at 40 C.F.R. § 61.342(e) (6 Mg option), are required to: 1) manage and treat all facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of 40 C.F.R. § 61.342(c)(1); and 2) manage and treat all facility waste with a flow-weighted annual average water content greater than or equal to 10 percent, and all wastes that are mixed with water or other wastes where the mixture has a flow weighted annual average water content greater than or equal to 10 percent, such that the benzene quantity, as determined by the procedures in 40 C.F.R. § 61.355(k) is less than or equal to 6 Mg/yr.

**Explanation of Violations**

1. BP Whiting is a petroleum refinery, as defined at 40 C.F.R. § 61.341. Thus, it is subject to the requirements of the Benzene Waste NESHAP.

2. BP Whiting's total annual benzene quantity, calculated pursuant to 40 C.F.R. § 61.342(a), is greater than 10 Mg/yr. Therefore, BP is required to manage and treat facility waste in accordance with 40 C.F.R. § 61.342(c), (d), or (e).

3. BP has chosen to comply with the 6 Mg option found at 40 C.F.R. § 61.342(e) at BP Whiting.

4. Pursuant to 40 C.F.R. § 61.357(d), on February 10, 2009, BP submitted the total annual benzene quantity report for calendar year 2008 (2008 TAB Report) to EPA. The 2008 TAB Report for BP Whiting lists the benzene quantity at 95.19 Mg

5. For calendar years 2003 – 2008, EPA alleges that BP exceeded the 6 Mg option, in violation of 40 C.F.R. § 61.342(e).

**Environmental Impact of Violations**

1. Benzene is a known human carcinogen, shown to cause leukemia. Other chronic effects of exposure include bone marrow depression leading to aplastic anemia, mutagenicity, fetotoxicity, decreased fertility, and possible drying and scaling of the skin. Among the acute health effects associated with benzene exposure are dizziness and lightheadedness; eye, nose and throat irritation; upset stomach and vomiting; irregular heartbeat;

convulsions and death. Ecological effects include death in exposed animal, bird and fish populations and death or reduced growth rate in plant life.

5/18/09
Date

Cheryl L. Newton
Director
Air and Radiation Division

**CERTIFICATE OF MAILING**

I, Betty Williams, certify that I sent Finding of Violation, No. EPA-5-09-IN-13, by Certified Mail, Return Receipt Requested, to:

Daniel Sajkowski, Business Unit Leader
BP Products North America, Inc.
2815 Indianapolis Boulevard
Whiting, Indiana 46394

I also certify that I sent copies of the Finding of Violation by first class mail to:

Phil Perry, Chief
Compliance and Enforcement Branch
Office of Air Quality
Indiana Department of Environmental Management
100 North Senate Avenue, Room 1001
Indianapolis, Indiana 46206-6015

on the 19th day of May, 2009.

Betty Williams

Betty Williams, Secretary
AECAS, (IL/IN)

CERTIFIED MAIL RECEIPT NUMBER: 70010320000601860781

**United States Environmental Protection Agency**
Region 5

| | | |
|---|---|---|
| **IN THE MATTER OF:** | ) | |
| | ) | |
| **BP Products North America, Inc.** | ) | |
| **Whiting, Indiana** | ) | **FINDING OF VIOLATION** |
| | ) | |
| | ) | **EPA-5-10-04-IN** |
| **Proceedings Pursuant to** | ) | |
| **the Clean Air Act,** | ) | |
| **42 U.S.C. §§ 7401 et seq.** | ) | |

## FINDING OF VIOLATION

The U.S. Environmental Protection Agency finds that BP Products North America, Inc. (BP or you) is violating certain provisions of the New Source Performance Standards, 40 C.F.R. Part 60 (NSPS), and the National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 C.F.R. Part 63 (NESHAP for Source Categories), including, but not limited to: 40 C.F.R. § 60.11(d); 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. § 63.11(b). These violations arise out of BP's improper operation of four of its refinery flares.

### Statutory and Regulatory Authority

This Finding of Violation is based on the following statutory and regulatory provisions:

**New Source Performance Standards (NSPS)**

1. Section 111(b)(1)(A) of the Act, 42 U.S.C. § 7411(b)(1)(A), required EPA to establish and publish a list of stationary source categories which "cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Pursuant to Section 111(b)(1)(B) of the Act, EPA has established technology-based standards for 68 new source categories. General NSPS provisions applying to source categories are set forth at 40 C.F.R. Part 60, Subpart A, §§ 60.1-60.19. NSPS general provisions apply to all NSPS source categories unless explicitly exempted in a specific subpart.

**40 C.F.R. § 60.11(d): Good Air Pollution Control Practices**

2. The general NSPS provision at Section 60.11(d) provides as follows: At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility

including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

**40 C.F.R. § 60.18(b): General Requirements for Flares**

3. NSPS subparts that require or allow the use of a flare as a control device reference 40 C.F.R. § 60.18(b) for the applicable compliance parameters for the operation and maintenance of flares. Section 60.18(b) references specific provisions in Section 60.18 (c)-(f), which set forth flaring requirements. Section 60.18(c)(1) provides that "[f]lares shall be designed for and operated with no visible emissions . . .." Section 60.18(c)(3)(ii) provides that flares shall be used only with the net heating value of the gas being combusted at 300 BTU or greater if the flare is steam-assisted. Section 60.18(c)(4) provides that steam-assisted flares "shall be designed for and operated with an exit velocity . . . less than . . . 60 feet/sec . . .." Section 60.18(d) provides that "[o]wners and operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs."

**40 C.F.R. Part 60, Subpart VV: NSPS Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry**

4. Certain subparts under NSPS and NESHAP for source categories (40 C.F.R. Part 63) which regulate equipment leaks of volatile organic chemicals (VOC) require compliance with 40 C.F.R. Part 60, Subpart VV. Under Subpart VV, the group of all equipment within a process unit is an affected facility. 40 C.F.R. § 60.480(a)(2). Equipment includes each valve, pump, compressor, pressure relief device, sampling system, and open-ended line in VOC service. 40 C.F.R. § 60.481.

5. The Subpart VV regulation includes requirements for control devices, including flares, used in conjunction with control of equipment leaks. Section 60.482-10 sets forth standards for closed vent systems and control devices used to comply with the provisions of Subpart VV. Section 60.482-10(d) provides that flares used to comply with Subpart VV must comply with Section 60.18 of Part 60, Subpart A, General Provisions. Section 60.482-10(e) provides that owners of control devices, including flares, that are used to comply with the requirements of Subpart VV, "shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs."

**40 C.F.R. Part 60, Subpart GGG: NSPS Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries**

6. EPA promulgated the final standards of performance for equipment leaks of volatile organic compounds (VOC) in the petroleum refining industry on May 30,

1984. 49 Fed. Reg. 22598. An affected facility under Subpart GGG includes "all the equipment within a process unit" of a refinery. Under Subpart GGG, equipment includes each valve, pump, pressure relief device, open-ended valve or line or other connector within VOC service (that is, contain at least 10% VOC by weight; 49 Fed. Reg. at 22598). Pursuant to 40 C.F.R. § 60.592(a), each owner or operator subject to Subpart GGG is directed to comply with the Standards of 40 C.F.R. Part 60, Subpart VV, at §§ 60.482-1 to 60.482-10. Further, because Subpart GGG is a NSPS subpart, all of the general provisions under Subpart A apply to sources subject to Part 60, Subpart GGG. Therefore, Section 60.11(d), which requires compliance with good air pollution control practices for minimizing emissions, applies to sources subject to Subpart GGG.

**National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 C.F.R. Part 63 (NESHAP for Source Categories)**

7. The Clean Air Act Amendments of 1990 amended Section 112 of the Act to implement a technology-based approach to the control of hazardous air pollutants based upon the control of categories of sources which emit the greatest amount of HAPs. Section 112(b) of the Act lists 188 HAPs that cause adverse health or environmental effects. Section 112(d) of the Act requires the Administrator to promulgate regulations establishing emissions standards for each category or subcategory of major and area sources of HAPs. The General Provisions for the Part 63 NESHAP standards are set forth at 40 C.F.R. Part 63, Subpart A, §§ 63.1 - 63.15.

**40 C.F.R. § 63.6(e)(1)(i): Good Air Pollution Control Practice**

8. The NESHAP for Source Categories general provision at Section 63.6(e)(1)(i) provides as follows:

> Operation and maintenance requirements. (1)(i) At all times, including periods of startup, shutdown, and malfunction, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected source to the greatest extent which is consistent with safety and good air pollution control practices. The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require the owner or operator to achieve emissions levels that would be required by the applicable standard at other times if this is not consistent with safety and good air pollution control practices, nor does it require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved.

**40 C.F.R. § 63.11(b): Flare Requirements**

9. 40 C.F.R. § 63.11 addresses requirements pertaining to the operation of flares. These requirements include, Section 63.11(b)(4), which provides that "[f]lares shall be designed for and operated with no visible emissions . . ."; Section 63.11(b)(6)(ii), which provides that steam-assisted flares "shall be used only with the net heating value of the gas being combusted at . . . 300 BTU/scf or greater . . ."; and, Section 63.11(b)(7)(i), which provides that steam-assisted flares "shall be designed and operated with an exit velocity less than . . . 60 ft/sec . . .." Further, Section 63.11(b)(1) provides that "[o]wners or operators using flares to comply with the provisions of this part shall monitor these control devices to assure that they are operated and maintained in conformance with their designs."

**40 C.F.R. Part 63, Subpart CC: National Emission Standards for Hazardous Air Pollutants: Petroleum Refineries**

10. EPA promulgated the NESHAP for petroleum refineries on August 18, 1995, based on EPA's determination that petroleum refineries are major sources of HAP emissions. 60 Fed Reg. 43244. Subpart CC applies to petroleum refining process units and to related emission points. Section 63.640(c) provides that for "the purposes of this subpart, the affected source shall comprise all emission points, in combination," listed at Section 63.640(c)(1) through (c)(7). These emission points include miscellaneous process vents and all equipment leaks. 40 C.F.R. §§ 63.640(a) and (c)(1) and (4).

11. Section 63.643 sets forth requirements for Group 1 miscellaneous process vents. A Group 1 miscellaneous process vent means a process vent for which the total organic HAP concentration is greater than or equal to 20 parts per million by volume and the total VOC emissions are greater than 33 kilograms per day for existing sources or 6.8 kilograms per day for new sources. 40 C.F.R. § 63.641. Owners or operators of Group 1 miscellaneous process vents have two control options under Section 63.643(a) (1) and (2). The pertinent control option in this matter is 40 C.F.R. § 63.643(a)(1), which requires the reduction of emission of organic HAP's using a flare that meets the requirements of Part 60, Subpart A, Section 63.11(b). These requirements include 40 C.F.R. § 63.11(b)(1), which requires that flares are operated in conformance with their designs.

12. Section 63.648 sets forth requirements for equipment leaks. 40 C.F.R. § 63.648(a) provides that "[e]ach owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 C.F.R. part 60 subpart VV…." As stated above, Section 60.482-10(e) of 40 C.F.R. Part 60, Subpart VV, requires that owners of flares that are used to comply with the requirements of Subpart VV "shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs."

13. Table 6 to 40 C.F.R. Part 63, Subpart CC, titled "General Provisions Applicability to Subpart CC," specifically provides that Section 63.6(e) of the General

Provisions applies to affected sources under Subpart CC (except for "Group 2 emission points"). Table 6 further provides that 40 C.F.R. § 63.11(b) applies to all affected sources regulated by Subpart CC. As stated above, 40 C.F.R. § 63.6(e)(1) is the good air pollution control practice provision for NESHAPs for source categories and 40 C.F.R. § 63.11 sets forth operating and maintenance parameters (including compliance with design) for flares.

**40 C.F.R. Part 63, Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units (CCU), Catalytic Reforming Units (CRU), and Sulfur Recovery Units (SRU).**

14. EPA promulgated Part 63, Subpart UUU, known as the Refinery MACT II, on April 11, 2002. 67 Fed. Reg. 17762. Subpart UUU was subsequently amended by a direct final rule on February 9, 2005. 70 Fed. Reg. 6930. The NESHAP establishes emission limits for HAPs emitted from vents on the following types of process units: catalytic cracking units, catalytic reforming units, or sulfur recovery units. Section 63.1562(a), provides that Subpart UUU applies to each new, reconstructed, or existing affected source at a petroleum refinery. Section 63.1562(b) provides that an affected source under Subpart UUU includes process vents on catalytic reforming units that are associated with the regeneration of catalyst.

15. Section 63.1566 sets forth requirements for organic HAP emissions from catalytic reforming units. Specifically, 40 C.F.R. § 63.1566(a)(1)(i), which is one of two options available to control vent emissions of total organic compounds (TOC), provides that the TOC be directed to a flare meeting the control device requirements of 40 C.F.R. § 63.11(b). Further, the section references Table 15 to Subpart UUU, which affirms the applicability of Section 63.11(b).

16. Table 44 to Subpart UUU provides that certain General Provisions from 40 C.F.R. Part 63, Subpart A, apply to affected sources regulated under Subpart UUU. These include 40 C.F.R. § 63.6(e)(1)-(2) and 40 C.F.R. § 63.11. As stated above, 40 C.F.R. § 63.6(e)(1) is the good air pollution control practice provision for NESHAPs for source categories and 40 C.F.R. § 63.11 sets forth operating and maintenance parameters (including compliance with design) for flares.

**Factual Allegations and Explanation of Violations**

17. BP Products North America, Inc. (BP or you) owns and operates a refinery at 2815 Indianapolis Boulevard, Whiting, Indiana.

18. The Title V permit for BP at Section D.35 page 1, provides a table listing all of the refinery flares, and the process units that are normally controlled by the flare systems. The following flares and the process units they control are the subject of this FOV and are as follows:

a. FCU flare normally controls Fluid Catalytic Cracking Unit 600 (FCU 600);

b. UIU flare normally controls the Isomerization Unit (ISOM), Ultraformer No. 3 (3UF), No. 2 Treatment Plant (2TP), and Catalytic Refining Unit (CRU);

c. Alky flare normally controls the Propylene Concentration Unit (PCU), and the Alkylation unit;

d. DDU flare normally controls the Distillate Desulfurizer Unit (DDU), Hydrogen Unit (HU), Coker, and Distillate Hydrotreating Unit (DHT).

19. The Title V permit for BP at Section D.22.4, and D.22.5, provides that FCU 600 is subject to: 40 C.F.R. Part 63, Subpart CC, 40 C.F.R. Part 63, Subpart UUU respectively. Therefore, FCU 600 is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

20. The Title V permit for BP at section D.9.4, and D.9.5, provides that the ISOM unit is subject to 40 C.F.R. Part 63, Subpart CC. Therefore, the ISOM unit is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

21. The Title V permit for BP at section D.15.4, D.15.5, and D.15.7, provides that 3UF is subject to: 40 C.F.R. Part 63, Subpart CC, 40 C.F.R. Part 63, Subpart UUU respectively. Therefore, 3UF is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

22. The Title V permit for BP at section D.12.1, provides that 2TP is subject to 40 C.F.R. Part 63, Subpart CC. Therefore, 2TP is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

23. The Title V permit for BP at section D.20.4, provides that the CRU is subject to 40 C.F.R. Part 60, Subpart GGG, and 40 C.F.R. Part 63, Subpart CC. Therefore, the CRU is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.11(d); 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

24. The Title V permit for BP at section D.8.1, provides that the PCU is subject to 40 C.F.R. Part 63, Subpart CC. Therefore, the PCU is subject to, among other things, the good air pollution control practices provisions and the flare operation

and maintenance provisions at: 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

25. The Title V permit for BP at section D.7.2, provides that the Alky is subject to 40 C.F.R. Part 63, Subpart CC. Therefore, the Alky is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

26. The Title V permit for BP at section D.18.5, provides that the DDU is subject to 40 C.F.R. Part 60, Subpart GGG, and 40 C.F.R. Part 63, Subpart CC. Therefore, the DDU is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.11(d); 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

27. The Title V permit for BP at section D.17.5, provides that the HU is subject to 40 C.F.R. Part 60, Subpart GGG, and 40 C.F.R. Part 63, Subpart CC. Therefore, the HU is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.11(d), 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

28. The Title V permit for BP at section D.2.4, provides that the Coker is subject to 40 C.F.R. Part 60, Subpart GGG, and 40 C.F.R. Part 63, Subpart CC. Therefore, the Coker is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.11(d); 40 C.F.R. § 60.18(b), 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

29. The Title V permit for BP at section D.37.3, provides that the DHT unit is subject to 40 C.F.R. Part 63, Subpart CC. Therefore, the DHT unit is subject to, among other things, the good air pollution control practices provisions and the flare operation and maintenance provisions at: 40 C.F.R. § 60.18(b); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. §63.11(b).

30. BP uses the FCU, UIU, Alky, and DDU flares to control emission from process units, including emissions resulting from malfunctions and pressure relief episodes.

31. The FCU, UIU, Alky, and DDU flares are steam assisted, which means that steam is added to the waste, or vent gas stream to enhance combustion and prevent the formation of smoke. Steam is added in proportion to the amount of vent gas, and it is common practice to measure to the amount of steam as a ratio of the mass of steam per unit mass of vent gas (lb/lb).

32. On August 27, 2009, BP provided information to EPA in response to an EPA information request, including operating data on the FCU, UIU, Alky, and DDU flares for the period from July 1, 2006 through July 28, 2009, and flare design documents.

33. BP's Instruction Manual for the FCU flare, written by NAO, Inc., the flares' manufacturer, states that "the amount of steam needs to be regulated in relation to the amount of relief gas," and sets forth the design vent gas flow rate and associated steam flow rate. Specifically, it states that the flare's design flowrates are 42,000 lb/hr of steam and 110,000 lb/hr of vent gas. These flow rates result in a steam-to-vent gas ratio of approximately 0.4 lb steam/lb vent gas at these design conditions.

34. BP's Instruction Manual for the UIU flare, written by NAO, Inc., the flares' manufacturer, states that "the steam level is adjusted so that is sufficient to suppress any smoking," and sets forth the design vent gas flow rate and associated steam flow rate. Specifically, it states that the flare's design flowrates are 23,500 lb/hr of steam and 58,750 lb/hr of vent gas. These flow rates result in a steam-to-vent gas ratio of approximately 0.4 lb steam/lb vent gas at these design conditions.

35. BP's Instruction Manual for the Alky flare, written by NAO, Inc., the flares' manufacturer, states that "the amount of steam needs to be regulated in relation to the amount of relief gas," and sets forth the design vent gas flow rate and associated steam flow rate. Specifically, it states that the flare's design flowrates are 33,750 lb/hr of steam and 75,000 lb/hr of vent gas. These flow rates result in a steam-to-vent gas ratio of approximately 0.4 lb steam/lb vent gas at these design conditions.

36. BP's Instruction Manual for the DDU flare, written by Callidus Technologies, LLC, the flares' manufacturer, sets forth the design vent gas flow rate and associated steam flow rate. Specifically, it states that the flare's design flowrates are 63,000 lb/hr of steam and 220,000 lb/hr of vent gas. These flow rates result in a steam-to-vent gas ratio of approximately 0.3 lb steam/lb vent gas at these design conditions.

37. The steam-to-vent gas ratio set forth in the Instruction Manual for the flares is consistent with good engineering practice as set forth in industry, academic, and government publications concerning the operation of flares, e.g.:

   a. In March 1997, the American Petroleum Institute (API) released a report entitled "Guide for Pressure-Relieving and Depressuring Systems." The document discusses proper practices for venting organic material. With respect to smoke suppression at steam-assisted flares, the authors of the document state, "the amount of steam required is primarily a function of the gas composition, flow rate and steam pressure and flare tip design and is normally in the range of 0.25 to 1.0. [lb/lb]".

   b. In July 1983, EPA released report EPA 600/2-83-052, titled Flare Efficiency Study. This study, partially funded by EPA and the Chemical Manufacturers Association (CMA), included various tests to determine the combustion efficiency and hydrocarbon destruction efficiency of flares under a variety of operating conditions. The tests performed included a wide range of steam flows and steam-to-vent gas ratios. The data collected showed decreasing combustion efficiencies when the steam-to-vent gas ratio increased. The report's authors indicated they believed excessive steam-to-vent gas ratios caused steam quenching of the flame during the tests which resulted in lower combustion efficiency. The report on page 37 states "This data suggests that steam-to-relief gas ratios ranging from 0.4 to 1.5 yield the best combustion efficiencies." The report also states on page 28 that steam-to-vent gas ratios above 3.07, "are regarded as being higher than those that would represent good engineering practice."

38. BP occasionally provided steam to the FCU, UIU, DDU, and Alky flares in excess of their design steam-to-vent gas ratio. This excess steam resulted in steam-to-vent gas ratios that exceeded 10 lb/lb as three-hour averages.

39. This failure to adhere to the flare's design and good air pollution control practices resulted in excess steam being added to the FCU, UIU, DDU, and Alky flares on several days in 2006, 2007, 2008, and 2009, which likely reduced the combustion efficiency of the flares. The reduction in combustion efficiency resulted in increased emissions. BP's actions are violations of the good air pollution control practices provisions and the flare operation and maintenance provisions under NSPS and NESHAP, as well as the underlying violations of NSPS Subpart GGG and NESHAP Subparts CC and UUU.

**Environmental Impact of Violations**

40. These violations have caused or can cause excess emissions of VOCs and/or HAPs. VOC cause ground level ozone, which can irritate the human respiratory system and reduce lung function. The health effects from HAPs include birth defects, cancer, and respiratory ailments.

2/11/10
Date

Cheryl L. Newton
Director
Air and Radiation Division

**CERTIFICATE OF MAILING**

I, Betty Williams, certify that I sent a Notice and Finding of Violation, No. EPA-5-10-04-IN, by Certified Mail, Return Receipt Requested, to:

Nick Spencer
Business Unit Leader
BP Products North America, Inc.
2815 Indianapolis Boulevard
Whiting, Indiana 46394

I also certify that I sent copies of the Finding of Violation and Notice of Violation by first class mail to:

Phil Perry, Chief
Compliance and Enforcement Branch
Office of Air Quality
Indiana Department of Environmental Management
100 North Senate Avenue, Room IGCN 1003
Indianapolis, Indiana 46204-2251

on the 17th day of February, 2010.

Betty Williams
Betty Williams
Administrative Program Assistant
AECAS, IL/IN

CERTIFIED MAIL RECEIPT NUMBER: 7009 168000007666 5162