IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF ILLINOIS

UNITED STATES OF AMERICA, STATE OF ILLINOIS, STATE OF LOUISIANA, and the STATE OF MONTANA Plaintiffs, v. EXXON MOBIL CORPORATION and EXXONMOBIL OIL CORPORATION Defendants.	)	No.

CONSENT DECREE

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CONSENT DECREE

WHEREAS, defendant Exxon Mobil Corporation currently owns and operates petroleum refineries located in Baton Rouge, Louisiana; Baytown, Texas; and Billings, Montana. Defendant ExxonMobil Oil Corporation (formerly known as Mobil Oil Corporation) currently owns and operates petroleum refineries located in Beaumont, Texas; Joliet, Illinois; and Torrance, California. As specified by Section IV of this Consent Decree: (i) Exxon Mobil Corporation and ExxonMobil Oil Corporation are referred to herein as "ExxonMobil;" and (ii) the six petroleum refineries identified above are referred to herein as the "Covered Refineries."

WHEREAS, plaintiff the United States of America ("Plaintiff" or the "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"), alleges upon information and belief that defendant ExxonMobil has violated and/or continues to violate certain requirements of the Clean Air Act, and the regulations and permits promulgated thereunder at the Covered Refineries.

WHEREAS, the United States specifically alleges that ExxonMobil has violated and/or continues to violate the following statutory and regulatory provisions:

1) Prevention of Significant Deterioration ("PSD") requirements found at Part C of Subchapter I of the Clean Air Act (the "Act"), 42 U.S.C. § 7475, and the regulations promulgated thereunder at 40 C.F.R. § 52.21 (the "PSD Rules"); and "Plan Requirements for Non-Attainment Areas" at Part D of Subchapter I of the Act, 42 U.S.C. §§ 7502-7503, and the regulations promulgated thereunder at 40 C.F.R. § 51.165(a) and (b), 40 C.F.R. Part 51, Appendix S, and 40 C.F.R. § 52.24 ("PSD/NSR Regulations"), for fuel

gas combustion devices and fluid catalytic cracking unit catalyst regenerators for NOx, SO_2, CO and PM;

2) New Source Performance Standards ("NSPS") found at 40 C.F.R. Part 60, Subparts A and J ("Refinery NSPS Regulations"), promulgated under Section 111 of the Act, 42 U.S.C. § 7411, for sulfur recovery plants, fuel gas combustion devices, and fluid catalytic cracking unit catalyst regenerators;

3) Leak Detection and Repair ("LDAR") requirements promulgated pursuant to Sections 111 and 112 of the Act, and found at 40 C.F.R. Part 60 Subpart GGG; 40 C.F.R. Part 61, Subparts J and V; and 40 C.F.R. Part 63, Subparts F, H, and CC ("LDAR Regulations"); and

4) National Emission Standards for Hazardous Air Pollutants ("NESHAP") for Benzene Waste Operations promulgated pursuant to Section 112(e) of the Act, and found at 40 C.F.R. Part 61, Subpart FF ("Benzene Waste NESHAP Regulations").

WHEREAS, the United States also alleges upon information and belief that ExxonMobil has violated and/or continues to violate certain other legal requirements applicable to the Covered Refineries, including requirements imposed by the following statutes and the regulations promulgated thereunder: (i) the Clean Water Act (the "CWA"), 33 U.S.C. § 1251 et seq.; (ii) the Resource Conservation and Recovery Act ("RCRA"), 42 U.S.C. § 6901 et seq.; and (iii) the release reporting requirements found at Section 103(a) of the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), 42 U.S.C. § 9603(a), and Section 304 of the Emergency Planning and Community Right-to-Know Act ("EPCRA"), 42 U.S.C. § 11004.

WHEREAS, the United States also specifically alleges with respect to the Covered Refineries that, upon information and belief, ExxonMobil has been and/or continues to be in violation of the state implementation plans ("SIPs") and other state rules adopted by the states and/or local air quality districts in which the Covered Refineries are located to the extent that such plan or rules implement, adopt or incorporate the above-described Federal requirements.

WHEREAS, the State of Illinois (on behalf of the Illinois Environmental Protection Agency), the State of Louisiana (on behalf of the Louisiana Department of Environmental Quality), and the State of Montana (on behalf of the Montana Department of Environmental Quality) (referred to herein as the "Co-Plaintiffs") have joined in this matter to allege violations of their respective applicable SIP provisions and other state and local rules, regulations, and permits incorporating and/or implementing the foregoing federal requirements.

WHEREAS, with respect to the provisions of Subsection V.K ("Control of Acid Gas Flaring and Tail Gas Incidents") of this Consent Decree, EPA maintains that "[i]t is the intent of the proposed standard [40 C.F.R. § 60.104] that hydrogen-sulfide-rich gases exiting the amine regenerator [or sour water stripper gases] be directed to an appropriate recovery facility, such as a Claus sulfur plant," see Information for Proposed New Source Performance Standards: Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels, Secondary Lead Smelters and Refineries, Brass or Bronze Ingot Production Plants, Iron and Steel Plants, Sewage Treatment Plants, Vol. 1, Main Text at 28.

WHEREAS, EPA further maintains that the failure to direct hydrogen-sulfide-rich gases to an appropriate recovery facility -- and instead to flare such gases under circumstances that are not sudden or infrequent or that are reasonably preventable -- circumvents the purposes and intentions of the standards at 40 C.F.R. Part 60, Subpart J.

WHEREAS, EPA recognizes that "Malfunctions," as defined in Section IV (Definitions) of this Consent Decree and 40 C.F.R. § 60.2, of the "Claus Sulfur Recovery Plants" or of "Upstream Process Units" may result in flaring of "Acid Gas" or "Sour Water Stripper Gas" on occasion, as those terms are defined herein, and that such flaring does not violate 40 C.F.R. § 60.11(d) if the owner or operator, to the extent practicable, maintains and operates such units in a manner consistent with good air pollution control practice for minimizing emissions during these periods.

WHEREAS, ExxonMobil denies that it has violated and/or continues to violate the foregoing statutory, regulatory, SIP provisions and other state and local rules, regulations and permits incorporating and implementing the foregoing federal requirements, and maintains that it has been and remains in compliance with all applicable statutes, regulations and permits and is not liable for civil penalties and injunctive relief as alleged in the Complaint.

WHEREAS, the United States is engaged in a federal strategy for achieving cooperative agreements with U.S. petroleum refineries to achieve across-the-board reductions in emissions in a manner that achieves compliance with existing statutory and regulatory standards ("Global Settlement Strategy").

WHEREAS, ExxonMobil consents to the simultaneous filing of the Complaint and lodging of this Consent Decree so as to accomplish its objective of cooperatively reconciling the goals of the United States, the Co-Plaintiffs, and ExxonMobil under the Clean Air Act and the corollary state statutes, and ExxonMobil therefore agrees to undertake the installation of air pollution control equipment and enhancements to its air pollution management practices set forth in this Consent Decree at the Covered Refineries to reduce air emissions through participation in the Global Settlement Strategy.

WHEREAS, even before entry into the settlement negotiations that resulted in this Consent Decree, ExxonMobil had taken significant steps to reduce air pollutant emissions from the Covered Refineries, including by: 1) installing the first selective catalytic reduction ("SCR") NOx control system on any fluid catalytic cracking unit ("FCCU") in the United States, at its Torrance Refinery in 2000; and 2) installing wet gas scrubber ("WGS") SO_2 and PM control systems on its Baton Rouge Refinery FCCUs (which commenced operation in 1976) and Baytown Refinery FCCUs (which commenced operation in 1974 and 1975).

WHEREAS, by entering into this Consent Decree, ExxonMobil is committed to making further reductions in air pollutant emissions from its operations.

WHEREAS, the United States, the Co-Plaintiffs, and ExxonMobil estimate that, when the affirmative relief and environmental projects identified in Sections V and VIII of this Consent Decree are fully implemented, annual emissions from the Covered Refineries will be reduced by the following amounts, as compared to historical baseline emissions: 1) nitrogen oxide by approximately 10,200 tons; and 2) sulfur dioxide by approximately 40,700 tons.

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

WHEREAS, coordinated negotiations between the United States and ExxonMobil and Chalmette Refining, L.L.C. – addressing multiple petroleum refineries owned and/or operated by those entities – resulted in two complementary Consent Decrees, namely: (i) this Consent Decree with ExxonMobil (relating to the Covered Refineries); and (ii) a separate Consent Decree with Chalmette Refining, L.L.C. that has been lodged with the United States District Court for the Eastern District of Louisiana (relating to a refinery in Chalmette, Louisiana that is owned by

Chalmette Refining, L.L.C. and operated for and on behalf of Chalmette Refining, L.L.C. by ExxonMobil Oil Corporation).

WHEREAS, the Parties agree that: (i) settlement of the matters set forth in the Complaint (filed herewith) and in Section XVI (Effect of Settlement) of this Consent Decree is in the best interests of the Parties, and the public; and (ii) entry of this Consent Decree without litigation is the most appropriate means of resolving this matter.

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 Section XVI of the Consent Decree, 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 Clean Air Act, 42 U.S.C. §§ 7413(b) and 7477, Section 309(b) of the CWA, 33 U.S.C. § 1319(b), Section 3008(a) of RCRA, 42 U.S.C. § 6928(a), Section 109(c) of CERCLA, 42 U.S.C. § 9609(c), and Section 325(b) of EPCRA, 42 U.S.C. § 11045(b). The Complaint states a claim upon which relief may be granted for injunctive relief and civil penalties against ExxonMobil under the Clean Air Act, the CWA, RCRA, CERCLA Section 103, and EPCRA Section 304. Authority to bring this suit is vested in the United States Department of Justice by 28 U.S.C. §§ 516 and 519.

2. Venue is proper in the Northern District of Illinois pursuant to Section 113(b) of the Clean Air Act, 42 U.S.C. § 7413(b), CWA Section 309(b), 33 U.S.C. § 1319(b), RCRA Section 3008(a), 42 U.S.C. § 6928(a), CERCLA Section 113(b), 42 U.S.C. § 9613(b), EPCRA Section 325(b)(3), 42 U.S.C. § 11045(b)(3), and 28 U.S.C. §§ 1391(b) and (c), and 1395(a). ExxonMobil 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 Co-Plaintiffs as parties or intervenors in this action.

3. Notice of the commencement of this action has been given to the State of Illinois, the State of Louisiana, the State of Montana, the State of Texas, the California Air Resources Board, and the South Coast Air Quality Management District, in accordance with Section 113(a)(1) of the Clean Air Act, 42 U.S.C. § 7413(a)(1), and as required by Section 113(b) of the Clean Air Act, 42 U.S.C. § 7413(b).

II. APPLICABILITY AND BINDING EFFECT

4. The provisions of the Consent Decree shall apply to the Covered Refineries. The provisions of the Consent Decree shall be binding upon the United States, the Co-Plaintiffs, and ExxonMobil, (acting through its officers, agents, servants, employees, and members acting in their capacities as such), and upon ExxonMobil's successors and assigns; provided, however, that all obligations of ExxonMobil herein related to the Baton Rouge, Baytown, or Billings Refineries shall be borne by Exxon Mobil Corporation, and all obligations of ExxonMobil herein related to the Beaumont, Joliet or Torrance Refineries shall be borne by ExxonMobil Oil Corporation.

5. ExxonMobil, the United States, and the Co-Plaintiffs agree not to contest the validity of the Consent Decree in any subsequent proceeding to implement or enforce its terms.

6. ExxonMobil shall give written notice of the Consent Decree to any successors in interest prior to the transfer of ownership or operation of any portion of any Covered Refinery (to the extent such portion is subject to one or more requirements of this Consent Decree) and shall provide a copy of the Consent Decree to any successor in interest. ExxonMobil shall notify the United States, and the Applicable Co-Plaintiff, in accordance with the notice provisions set forth in Paragraph 266 (Notice), of any successor in interest at least thirty (30) days prior to any such transfer.

7. ExxonMobil 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 interest), in any Covered Refinery, upon the execution by the transferee of a modification to the Consent Decree, which modification shall make the terms and conditions of the Consent Decree that apply to the Covered Refinery or portion of the Covered Refinery applicable to the transferee. In the event of such transfer, ExxonMobil shall notify the United States and the Applicable Co-Plaintiff. By no earlier than thirty (30) days after such notice, ExxonMobil may file a motion to modify the Consent Decree to make the terms and conditions of the Consent Decree applicable to the transferee. ExxonMobil shall be released from the obligations and liabilities of this Consent Decree unless the United States 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 the Consent Decree.

8. Subject only to Paragraph 7, above, and Sections VII (Modifications to Implementation Schedules) and XIV (Force Majeure), below, ExxonMobil shall be solely responsible for ensuring that performance of the work contemplated under this Consent Decree is undertaken in accordance with the deadlines and requirements contained in this Consent Decree

and any attachments hereto. ExxonMobil shall provide a copy of this Consent Decree (or an extract of applicable provisions of this Consent Decree) to each consulting or contracting firm that is retained to perform work required under Subsections V.N or V.O of this Consent Decree, upon execution of any contract relating to such work. Copies of the Consent Decree (or an extract of applicable provisions of this Consent Decree) may be provided by electronic means but do not need to be supplied to firms who are retained to supply materials or equipment to satisfy requirements under this Consent Decree.

III. OBJECTIVES

9. It is the purpose of the Parties in this Consent Decree to further the objectives of the federal Clean Air Act, the CWA, RCRA, CERCLA Section 103, EPCRA Section 304, the Illinois Environmental Protection Act, 415 Ill. Comp. Stat. 5/1 - 58.17, the Louisiana Environmental Quality Act, La. Rev. Stat. Ann. § 30:2001 et seq., and the Clean Air Act of Montana, Mont. Code Ann. §§ 75-2-101 - 75-2-429.

IV. DEFINITIONS

10. Unless otherwise defined herein, terms used in the Consent Decree shall have the meaning given to those terms in the Clean Air Act, the CWA, RCRA, CERCLA Section 103, EPCRA Section 304, and the implementing regulations promulgated thereunder. The following terms used in this Consent Decree shall be defined, for purposes of the Consent Decree and the reports and documents submitted pursuant hereto, as follows:

a. "Acid Gas" or "AG" 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 mean Tail Gas.

b. "Acid Gas Flaring" or "AG Flaring" shall mean the combustion of Acid Gas and/or Sour Water Stripper Gas in an AG Flaring Device. Nothing in this definition shall be construed to modify, limit, or affect EPA's authority to regulate the flaring of gases that do not fall within the definitions of Acid Gas or Sour Water Stripper Gas contained in this Decree.

c. "Acid Gas Flaring Device" or "AG Flaring Device" shall mean the devices identified in Appendix F that are used at the Covered Refineries to combust Acid Gas and/or Sour Water Stripper Gas. The term "Acid Gas Flaring Device" does not include facilities in which gases are combusted to produce sulfur or sulfuric acid. To the extent that, during the duration of the Consent Decree, any Covered Refinery utilizes any Flaring Devices other than those specified above for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, those Flaring Devices shall be AG Flaring Devices and shall be subject to the requirements of this Consent Decree.

d. "Acid Gas Flaring Incident" or "AG Flaring Incident" shall mean the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas from one or more AG Flaring Devices at a Covered Refinery that results in the emission of sulfur dioxide equal to, or in excess of, five-hundred (500) pounds in any twenty-four (24) hour period. Where such continuous or intermittent combustion from one or more AG Flaring Devices continues into subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), and sulfur dioxide equal to, or in excess of, five-hundred (500) pounds is emitted in each subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping twenty-four (24) hour periods are measured from the initial commencement of AG Flaring within the AG Flaring Incident.

e. “Applicable Co-Plaintiff” shall mean the following states with respect to the following refineries:

Baton Rouge Refinery	State of Louisiana through the LDEQ
Billings Refinery	State of Montana through the MDEQ
Joliet Refinery	State of Illinois on behalf of IEPA

f. “Average Weight % of Total Catalyst Added” (as determined on a 7-day rolling average basis) shall mean:

$$\frac{\text{Amount of SO2 Reducing Catalyst Added (in pounds per day as received)}}{\text{Total Catalyst Addition Rate (in pounds per day as received).}} \times 100 \text{ percent}$$

g. “CEMS” shall mean continuous emissions monitoring system.

h. “Combustion Units” shall mean the heaters, boilers, and gas turbines with a capacity of greater than 40 mmBtu/hr (at HHV) at the Covered Refineries that are listed in Appendix A.

i. “Consent Decree” or “Decree” shall mean this Consent Decree, including any and all appendices attached to the Consent Decree.

j. “Covered Refineries” shall mean the following petroleum refineries: (1) the Baton Rouge Refinery, owned and operated by Exxon Mobil Corporation and located at 4045 Scenic Highway in Baton Rouge, Louisiana; (2) the Baytown Refinery, owned and operated by Exxon Mobil corporation and located at 2800 Decker Drive in Baytown, Texas; (3) the Beaumont Refinery, owned and operated by ExxonMobil Oil Corporation and located at End of Burt Street in Beaumont, Texas; (4) the Billings Refinery, owned and operated by Exxon Mobil Corporation and located at 700 Exxon Refinery Road in Billings, Montana; (5) the Joliet Refinery, owned and operated by ExxonMobil Oil Corporation and located at I-55 and Arsenal

Road in Channahon, Illinois; and (6) the Torrance Refinery, owned and operated by ExxonMobil Oil Corporation and located at 3700 West 190th Street in Torrance, California.

k. "CO" shall mean carbon monoxide.

l. "Current Generation Ultra-Low NOx Burners" shall mean those burners that are designed to achieve a NOx emission rate of 0.020 to 0.040 lb/mmBTU HHV when firing natural gas at 3% stack oxygen at full design load without air preheat, regardless of whether upon installation actual emissions exceed 0.040 lb/mmBTU HHV.

m. "Date of Lodging" or "Date of Lodging of the Consent Decree" shall mean the date the Consent Decree is lodged with the Clerk of the Court for the United States District Court for the Northern District of Illinois.

n. "Day" or "Days" shall mean a calendar day or days.

o. "Entry Date" shall mean the date the Consent Decree is entered by the United States District Court for the Northern District of Illinois.

p. "ExxonMobil" shall mean Exxon Mobil Corporation and ExxonMobil Oil Corporation and their successors and assigns. For matters under this Consent Decree relating to the Baton Rouge Refinery, the Baytown Refinery, and/or the Billings Refinery, the term "ExxonMobil" shall mean Exxon Mobil Corporation and its successor and assigns. For matters under this Consent Decree relating to the Beaumont Refinery, the Joliet Refinery, and/or the Torrance Refinery, the term "ExxonMobil" shall mean ExxonMobil Oil Corporation and its successors and assigns. For matters relating to all of the Covered Refineries or to general rights and obligations under this Consent Decree, the term "ExxonMobil" shall mean both Exxon Mobil Corporation and ExxonMobil Oil Corporation, and their successors and assigns.

q. “FCCU” shall mean a fluidized catalytic cracking unit, its regenerator and associated CO boiler(s) and CO furnace(s) where present.

r. “Flaring Device” shall mean an AG Flaring Device and/or an HC Flaring Device.

s. “Flaring Incident” shall mean an AG Flaring Incident, a Tail Gas Incident, and/or an HC Flaring Incident.

t. “Fuel Oil” shall mean any liquid fossil fuel with sulfur content of greater than 0.05% by weight.

u. “Full Burn Operation,” when used with respect to the Billings Refinery FCCU, shall mean when essentially all of the CO produced in the FCCU regenerator is converted to CO_2 inside the regenerator and there is O_2 (greater than 0.5% by volume as measured on a daily basis) present in the regenerator flue gas.

v. “Hydrocarbon Flaring” or “HC Flaring” shall mean the combustion of refinery-generated gases, except for Acid Gas and/or Sour Water Stripper Gas and/or Tail Gas, in a Hydrocarbon Flaring Device. Nothing in this definition shall be construed to modify, limit, or affect EPA’s authority to regulate the flaring of gases that do not fall within the definitions contained in this Consent Decree.

w. “Hydrocarbon Flaring Device” or “HC Flaring Device” shall mean the devices listed in Appendix F that are used by the Covered Refineries to control (through combustion) any excess volume of a refinery-generated gas other than Acid Gas and/or Sour Water Stripper Gas and/or Tail Gas. To the extent that any Covered Refinery utilizes Flaring Devices other than those specified in Appendix F for the purpose of combusting any excess of a refinery-generated gas other than Acid Gas and/or Sour Water Stripper Gas, those Flaring

Devices shall be HC Flaring Devices and shall be subject to the provisions of this Consent Decree.

x. "Hydrocarbon Flaring Incident" or "HC Flaring Incident" shall mean the continuous or intermittent flaring of refinery-generated gases, except for Acid Gas or Sour Water Stripper Gas or Tail Gas, in a Hydrocarbon Flaring Device that results in the emission of sulfur dioxide equal to, or greater than five hundred (500) pounds in a 24-hour period. Where such continuous or intermittent flaring from a Hydrocarbon Flaring Device continues into subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), and sulfur dioxide equal to, or in excess of, five-hundred (500) pounds is emitted in each subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), then only one HC Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping twenty-four (24) hour periods are measured from the initial commencement of flaring within the HC Flaring Incident.

y. "IEPA" shall mean the Illinois Environmental Protection Agency and any successor department or agency of the State of Illinois.

z. "LDEQ" shall mean the Louisiana Department of Environmental Quality and any successor departments or agencies of the State of Louisiana.

aa. "Low NOx Combustion Promoter" shall mean a catalyst that is added to a FCCU that minimizes NOx emissions while maintaining its effectiveness as a combustion promoter.

ab. "Malfunction," as specified by 40 C.F.R. § 60.2, shall mean: "[A]ny 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."

ac. "MDEQ" shall mean the Montana Department of Environmental Quality and any successor department or agency of the State of Montana.

ad. "Natural Gas Curtailment" shall mean a restriction imposed by a natural gas supplier, which limits ExxonMobil's ability to obtain natural gas.

ae. "Next Generation Ultra-Low NOx Burners" or "Next Generation 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, regardless of whether upon installation actual emissions exceed 0.020 lb/mmBTU HHV.

af. "NOx" shall mean nitrogen oxides.

ag. "NOx Additives" shall mean Low NOx Combustion Promoters and NOx Reducing Catalyst Additives.

ah. "NOx Reducing Catalyst Additive" shall mean a catalyst additive that is introduced to an FCCU to reduce NOx emissions through reduction or controlled oxidation of intermediates.

ai. "NSPS Flaring Device" shall mean a Flaring Device listed in Appendix G.

aj. "Paragraph" shall mean a portion of this Consent Decree identified by an arabic numeral.

ak. "PM" shall mean particulate matter.

al. "Parties" shall mean the United States, the Co-Plaintiffs, and ExxonMobil.

am. "Root Cause" shall mean the primary cause(s) of AG Flaring Incident(s), Hydrocarbon Flaring Incident(s), or Tail Gas Incident(s), as determined through a process of investigation.

an. “Sour Water Stripper Gas” or “SWS Gas” shall mean the gas produced by the process of stripping or scrubbing refinery sour water.

ao. “SO_2 Reducing Catalyst Additive” shall mean a catalyst additive that is introduced to an FCCU to reduce SO_2 emissions by reduction and adsorption.

ap. “SO_2” shall mean sulfur dioxide.

aq. “Sulfur Recovery Plant” or “SRP” shall mean a process unit that recovers sulfur from hydrogen sulfide by a vapor phase catalytic reaction of sulfur dioxide and hydrogen sulfide. For the purposes of this Consent Decree, the SRPs at the refineries identified below shall be defined as follows:

(1) Baytown SRP: The SRP at the Baytown Refinery (the “Baytown SRP”) consists of four Claus trains: Claus A, Claus B, Claus C, and Claus D.

(2) Beaumont SRP: The SRP at the Beaumont Refinery (the “Beaumont SRP”) consists of three Claus trains: Claus 1, Claus 2, Claus 3.

(3) Joliet SRP: The SRP at the Joliet refinery (the “Joliet SRP”) consists of three Claus trains: North Train, East Train, and West Train.

(4) Torrance SRP: The SRP at the Torrance Refinery (the “Torrance SRP”) consists of two trains: Train A and Train B.

ar. “Tail Gas” or “TG” shall mean exhaust gas from the Claus trains and/or the tail gas cleanup unit (“TGU”) section of the SRP.

as. “Tail Gas Unit” or “TGU” shall mean a control system utilizing a technology for reducing emissions of sulfur compounds from a Claus Sulfur Recovery Plant.

at. “Tail Gas Incident” shall mean combustion of Tail Gas that either is:

(1) combusted in a flare and results in 500 pounds or more of SO_2 emissions in any 24 hour period ; or

(2) combusted in a thermal incinerator and results in excess emissions of 500 pounds or more of SO_2 in any 24-hour period. Only those time periods which are in

excess of a SO_2 concentration of 250 ppm (rolling 12-hour average) shall be used to determine the amount of excess SO_2 emissions from the incinerator.

ExxonMobil shall use engineering judgment and/or other monitoring data to estimate emissions during periods in which the SO_2 continuous emission analyzer has exceeded the range of the instrument or is out of service.

au. "Total Catalyst Addition Rate" shall mean the amount as an average (in pounds per day as received) of all forms of catalyst added to an FCCU during the two year baseline period from November 2001 to October 2003 (which amount was 3,607 pounds per day as received) including, but not limited to, base catalyst, equilibrium catalyst, and pollutant reducing catalyst.

av. "Upstream Process Units" shall mean all amine contactors, amine scrubbers, and sour water strippers at a Covered Refinery, as well as all process units at these refineries that produce gaseous or aqueous waste streams that are processed at amine contactors, amine scrubbers, or sour water strippers.

V. AFFIRMATIVE RELIEF

A. FLUID CATALYTIC CRACKING UNITS.

11. **Description of FCCUs.** ExxonMobil owns and/or operates the FCCUs identified below at the Covered Refineries.

a. Baton Rouge FCCUs: The Baton Rouge Refinery has two FCCUs, designated PCLA 2 and PCLA 3 (collectively the "Baton Rouge FCCUs"). A single Wet Gas Scrubber ("WGS") that commenced operation in 1976 serves as an SO_2 and PM control device for the Baton Rouge FCCUs.

b. Baytown FCCU 2 and Baytown FCCU 3: The Baytown Refinery has two FCCUs, designated FCCU 2 and FCCU 3. A WGS that commenced operation in 1974 serves as an SO_2 and PM control device for FCCU 2, and a WGS that commenced operation in 1975 serves as an SO_2 and PM control device for FCCU 3. A high-pressure hydrotreater also exists which lowers the sulfur in a portion of the FCCU feed.

c. Beaumont FCCU: The Beaumont Refinery has one FCCU. A WGS that commenced operation in 2004 serves as an SO_2 and PM control device for the FCCU. The Beaumont FCCU also has third-stage cyclones.

d. Billings FCCU: The Billings Refinery has one FCCU.

e. Joliet FCCU: The Joliet Refinery has one FCCU. The Joliet FCCU also has third-stage cyclones.

f. Torrance FCCU: The Torrance Refinery has one FCCU. A selective catalytic reduction ("SCR") system installed in 2000 serves as a NO_x control device for the FCCU. An electrostatic precipitator that commenced operation in 1972 and was upgraded in 1985 serves as a PM control device for the FCCU. A high-pressure hydrotreater also exists which lowers the sulfur in a portion of the FCCU feed.

B. NOx EMISSIONS REDUCTIONS FROM THE FCCUs.

12. **General.** ExxonMobil shall implement a program to reduce NO_x emissions from the FCCUs at the refineries listed in Subsection V.A, as specified below. Pursuant to Subsection V.Q of this Consent Decree, ExxonMobil shall apply for federally-enforceable permits that incorporate the lower NO_x emission limits established by this Subsection. ExxonMobil will monitor compliance with the emission limits through the use of CEMS, as specified by this Subsection V.B.

13. **<u>NOx Emissions Control for the Baton Rouge FCCUs.</u>**

a. <u>NOx Control System</u>. By no later than the Entry Date, ExxonMobil shall control NOx emissions from the Baton Rouge FCCUs. ExxonMobil presently intends to control NOx emissions from the Baton Rouge FCCUs by: (i) operating a Thermal DeNOx system; and (ii) shifting the FCCUs to a lower CO operation mode. ExxonMobil has used best efforts to design the NOx control system to attain, under optimum conditions, 50 ppmvd NOx or less (at 0% O_2 on a 365-day rolling average basis) and 100 ppmvd NOx or less (at 0% O_2 on a 7-day rolling average basis). Nothing in this Subparagraph 13.a shall be deemed to limit ExxonMobil's ability to implement or use additional NOx reducing measures.

b. <u>Final NOx Limits</u>.

(1) The long-term Final NOx Limit for the Baton Rouge FCCUs shall be set based on application of the provisions in Subparagraph 15.c., and shall be: (i) in the range of 50-60 ppmvd NOx (at 0% O_2 on a 365-day rolling average basis); and (ii) as close to 50 ppmvd as practicable. ExxonMobil shall comply with the long-term Final NOx Limit upon submission of the Study report referenced in Subparagraphs 15.b. and 15.c.

(2) The short-term Final NOx Limit for the Baton Rouge FCCUs shall be set based on application of the provisions in Subparagraph 15.c., and shall be: (i) in the range of 100-120 ppmvd NOx (at 0% O_2 on a 7-day rolling average basis); and (ii) as close to 100 ppmvd as practicable. ExxonMobil shall comply with the short-term Final NOx Limit upon submission of the Study report referenced in Subparagraphs 15.b. and 15.c.

14. **NOx Emissions Control for the Beaumont FCCU.**

a. NOx Control System. By no later than April 1, 2008, ExxonMobil shall control NOx emissions from the Beaumont FCCU. ExxonMobil presently intends to control NOx emissions from the Beaumont FCCU by: (i) installing and operating a Thermal DeNOx system; (ii) installing and operating CO boiler low-NOx burners; and/or (iii) shifting the FCCU to a lower CO operation mode. ExxonMobil shall use best efforts to design the NOx control system to attain 50 ppmvd NOx or less (at 0% O_2 on a 365-day rolling average basis) and 100 ppmvd NOx or less (at 0% O_2 on a 7-day rolling average basis); provided, however, that ExxonMobil shall not be required to design the control system in a manner that creates a safety problem or impairs unit feed rate, conversion, feed slate or yield selectivity. Nothing in this Subparagraph 14.a shall be deemed to limit ExxonMobil's ability to implement or use additional NOx reducing measures.

b. Final NOx Limits.

(1) The long-term Final NOx Limit for the Beaumont FCCU shall be set based on application of the provisions in Subparagraph 15.c., and shall be: (i) in the range of 50-60 ppmvd NOx (at 0% O_2 on a 365-day rolling average basis); and (ii) as close to 50 ppmvd as practicable. ExxonMobil shall comply with the long-term Final NOx Limit upon submission of the Study report referenced in Subparagraphs 15.b. and 15.c.

(2) The short-term Final NOx Limit for the Beaumont FCCU shall be set based on application of the provisions in Subparagraph 15.c., and shall be: (i) in the range of 100-120 ppmvd NOx (at 0% O_2 on a 7-day rolling average basis); and (ii) as close to 100 ppmvd as practicable. ExxonMobil shall comply with the short-term Final

NOx Limit upon submission of the Study report referenced in Subparagraphs 15.b. and 15.c.

15. **<u>Baton Rouge and Beaumont NOx Minimization Studies</u>.** ExxonMobil shall complete 12-month studies of: (i) the Baton Rouge FCCUs' NOx control system, by no later than 12 months after the Entry Date (the "Baton Rouge NOx Minimization Study"); and (ii) the Beaumont FCCU NOx control system, by no later than July 1, 2009 (the "Beaumont NOx Minimization Study").

a. During each Study, ExxonMobil shall use best efforts to operate the FCCU and the NOx control system to achieve emissions as close as practicable to 50 ppmvd NOx (at 0% O_2 on a 365-day rolling average basis) and 100 ppmvd NOx (at 0% O_2 on a 7-day rolling average basis); <u>provided</u>, <u>however</u>, that ExxonMobil shall not be required to operate the FCCU(s) or the control system in a manner that creates a safety problem or impairs unit feed rate, conversion, feed slate or yield selectivity, unless reasonable steps can be taken to compensate for such impairment.

b. Within 90 days after the completion of each Study, ExxonMobil shall submit a written report to EPA that shall summarize the results of the Study and shall provide relevant CEMS data and FCCU feed and operating data on a daily or daily average basis as measured directly (where available) or as calculated (where necessary). Upon request by EPA, ExxonMobil shall submit any additional, readily available data that EPA determines it needs to evaluate the Study.

c. Based on the results of the Study, each Study report shall specify Final NOx Limits for the relevant FCCU(s) within the ranges set forth in Subparagraphs 13.b. and 14.b. ExxonMobil shall specify limits which reflect best efforts to achieve emissions as close as practicable to 50 ppmvd NOx (at 0% O_2 on a 365-day rolling average basis) and 100 ppmvd NOx (at 0% O_2 on a 7-day rolling average basis); provided, however, that ExxonMobil shall not be required to specify a limit below the upper end of the range that would create a safety problem or impair unit feed rate, conversion, feed slate or yield selectivity.

d. If any limit specified pursuant to Subparagraph 15.c is higher than 50 ppmvd NOx (at 0% O_2 on a 365-day rolling average basis) or 100 ppmvd NOx (at 0% O_2 on a 7-day rolling average basis), then the relevant Study report shall include a plan for making supplemental NOx emission reductions from Combustion Units at the relevant refinery, in accordance with the following table:

Long-Term Limit	or	**Short-Term Limit**	**Additional Required Reductions**
50 ppmvd		100 ppmvd	0 TPY NOx
51 ppmvd		101-102 ppmvd	12 TPY NOx
52 ppmvd		103-104 ppmvd	26 TPY NOx
53 ppmvd		105-106 ppmvd	42 TPY NOx
54 ppmvd		107-108 ppmvd	60 TPY NOx
55 ppmvd		109-110 ppmvd	80 TPY NOx
56 ppmvd		111-112 ppmvd	102 TPY NOx
57 ppmvd		113-114 ppmvd	126 TPY NOx
58 ppmvd		115-116 ppmvd	152 TPY NOx
59 ppmvd		117-118 ppmvd	180 TPY NOx
60 ppmvd		119-120 ppmvd	210 TPY NOx

Such supplemental NOx reductions: (i) shall be in addition to those NOx emission reductions from Combustion Units required by Subsection V.G of this Consent Decree, and shall not count toward the reductions required by that Subsection; and (ii) shall be quantified, made, and incorporated into federally-enforceable permits in a manner consistent with the approach outlined in Subsections V.G and V.Q of this Consent Decree. If supplemental NOx reductions are required under this Subparagraph, then ExxonMobil's Study report shall include a definitive schedule for making the supplemental NOx reductions, and for submitting a completion report documenting the reductions. The schedule shall be subject to EPA approval, which shall not be unreasonably withheld.

16. **<u>NOx Emissions Control for the Baytown FCCUs</u>.**

a. <u>NOx Control Systems</u>.

(1) ExxonMobil presently intends to control NOx emissions from Baytown FCCU 2 by: (i) continuing to operate the FCCU in full burn mode; and (ii) taking other steps to reduce NOx (which may include, but are not limited to, use of a Thermal DeNOx system and/or use of NOx-reducing catalyst additive and/or low NOx combustion promoter).

(2) ExxonMobil presently intends to control NOx emissions from Baytown FCCU 3 by installing and operating a scrubber-based NOx emission reduction technology.

b. <u>Interim NOx Limits</u>.

(1) By no later than December 31, 2006, ExxonMobil shall specify and comply with separate long-term and short-term interim NOx emission limits for Baytown FCCU 2 and Baytown FCCU 3. Those Interim NOx Limits shall apply until Final NOx Limits are established under Subparagraph 16.c. The weighted average of the two sets of unit-specific interim limits shall not exceed:

Long-term limit: 65 ppmvd NOx on a 365-day rolling average basis at 0% O_2

Short-term limit: 95 ppmvd NOx on a 7-day rolling average basis at 0% O_2

In computing the average, the individual limits will be weighted based on each unit's flue gas flow rate. In addition, the unit-specific interim limits shall not exceed:

Long-term limit: 70 ppmvd NOx on a 365-day rolling average basis at 0% O_2

Short-term limit: 105 ppmvd NOx on a 7-day rolling average basis at 0% O_2

(2) In the Semi-Annual Report due on February 28, 2007 under Section IX, ExxonMobil shall specify the Interim NOx limits applicable to Baytown FCCU 2 and Baytown FCCU 3, which shall be consistent with the limitations imposed by Subparagraph 16.b.(1).

c. Final NOx Limits.

(1) By no later than June 30, 2010, ExxonMobil shall specify and comply with separate long-term and short-term final NOx emission limits for Baytown FCCU 2 and Baytown FCCU 3. The weighted average of the two sets of unit-specific final limits shall not exceed:

Long-term limit: 35 ppmvd NOx on a 365-day rolling average basis at 0% O_2

Short-term limit: 70 ppmvd NOx on a 7-day rolling average basis at 0% O_2

In computing the average, the individual limits will be weighted based on each unit's flue gas flow rate. In addition, the unit-specific final limits shall not exceed:

Long-term limit: 45 ppmvd NOx on a 365-day rolling average basis at 0% O_2

Short-term limit: 90 ppmvd NOx on a 7-day rolling average basis at 0% O_2

(2) In the Semi-Annual Report due on August 31, 2010 under Section IX, ExxonMobil shall specify the Final NOx limits applicable to Baytown FCCU 2 and Baytown FCCU 3, which shall be consistent with the limitations imposed by Subparagraph 16.c.(1).

17. **NOx Emissions Control for the Billings FCCU.**

a. NOx Control System. ExxonMobil presently intends to control NOx emissions from the Billings FCCU by: (i) converting the FCCU to Full Burn Operation; and

(ii) taking other steps to reduce NOx (which may include, but are not limited to, use of a Thermal DeNOx system and/or CO boiler low-NOx burners and/or use of NOx-reducing catalyst additive and/or low NOx combustion promoter).

b. Final NOx Limits. By no later than December 31, 2008, ExxonMobil shall comply with NOx emission limits of 40 ppmvd at 0% O_2 on a 365-day rolling average basis and 80 ppmvd at 0% O_2 on a 7-day rolling average basis at the Billings FCCU.

c. Non-Routine Operations. FCCU NOx emissions during a period of natural gas curtailment will not be used in determining compliance with the short-term (7-day) Final NOx Limit established pursuant to Subparagraph 17.b if Fuel Oil is burned in a combustion unit serving the Billings FCCU CO boiler or CO furnace during the period of natural gas curtailment. During any such period of natural gas curtailment, ExxonMobil shall comply with an alternate short-term NOx emission limit of 120 ppmvd at 0% O_2 on 24-hour rolling average basis at the Billings FCCU.

18. **NOx Emissions Control for the Joliet FCCU.**

a. NOx Control System. ExxonMobil presently intends to control emissions from the Joliet FCCU by installing and operating a SCR system for the FCCU.

b. Final NOx Limits. By no later than December 31, 2012, ExxonMobil shall comply with NOx emission limits of 20 ppmvd at 0% O_2 on a 365-day rolling average basis and 40 ppmvd at 0% O_2 on a 7-day rolling average basis at the Joliet FCCU.

19. **NOx Emissions Control for the Torrance FCCU.**

a. NOx Control System. ExxonMobil presently intends to control emissions from the Torrance FCCU by operating its existing SCR system for the FCCU.

b. Final NOx Limits. By no later than the Entry Date, ExxonMobil shall comply with NOx emission limits of 20 ppmvd at 0% O_2 on a 365-day rolling average basis and 40 ppmvd at 0% O_2 on a 7-day rolling average basis at the Torrance FCCU

c. Non-Routine Operations. For any period, not to exceed fourteen (14) days per occurrence, when the Torrance SCR is not operating because waste heat boiler 2F-7 is shut down for an internal boiler inspection required by Cal. Code Regs. Tit. 8, Section 770(b), NOx emissions from the Torrance FCCU will not be used in determining compliance with the short-term (7-day) Final NOx Limit established pursuant to Subparagraph 19.b. During any such period when waste heat boiler 2F-7 is shut down, ExxonMobil shall comply with a short-term NOx emission limit of 140 ppmvd at 0% O2 on 24-hour rolling average basis at the Torrance FCCU. Emissions during any such period shall either be: (i) monitored with CEMS as provided by Paragraph 21; or (ii) monitored in accordance with an alternative monitoring plan approved by EPA pursuant to this Consent Decree if it is necessary to bypass the FCCU's main stack during the particular period. In the first Semi-Annual Report that is due under Section IX after any such period, ExxonMobil shall identify the period during which waste heat boiler 2F-7 was shut down and shall describe why an internal boiler inspection was required by Cal. Code Regs. Tit. 8, Section 770(b).

20. **Startup, Shutdown, and Malfunction**. NOx emissions (i) caused by or attributable to the startup, shutdown, or Malfunction of an FCCU listed in Subsection V.A and/or (ii) during periods of Malfunction of the relevant FCCU's NOx Control System will not be used in determining compliance with the short-term (7-day) Interim NOx Limits or Final NOx Limits established pursuant to Subparagraphs 13.b.(2), 14.b.(2), 16.b, 16.c, 17.b, 18.b, and 19.b, provided that during such periods ExxonMobil implements good air pollution control practices

to minimize NOx emissions. Nothing in this Paragraph shall be construed to relieve ExxonMobil of any obligation under any federal, state, or local law, regulation, or permit to report emissions during periods of startup, shutdown, or Malfunction, or to document the occurrence and/or cause of a startup, shutdown, or Malfunction event. Emissions during any such period of startup, shutdown, or Malfunction shall either be: (i) monitored with CEMS as provided by Paragraph 21; or (ii) monitored in accordance with an alternative monitoring plan approved by EPA pursuant to this Consent Decree if it is necessary to bypass the FCCU's main stack during the particular period of startup, shutdown, or Malfunction.

21. **Demonstrating Compliance with FCCU NOx Emission Limits for the FCCUs.** By no later than the dates set out in Appendix N, ExxonMobil shall use NOx and O_2 CEMS at each of the FCCUs at the refineries listed in Subsection V.A to monitor performance and to report compliance with the terms and conditions of this Subsection V.B relating to NOx emissions from the FCCUs. As permitted by Subparagraph 19.c and Paragraph 20, emissions during certain periods may be monitored in accordance with an alternative monitoring plan approved by EPA. ExxonMobil shall make emissions monitoring data available to EPA as soon as practicable following an EPA request for such data. The CEMS shall be installed, calibrated and certified in accordance with 40 C.F.R. § 60.13 and Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B. For the Baton Rouge FCCUs, the Baytown FCCUs, the Beaumont FCCU, and the Torrance FCCU, unless Appendix F is otherwise required by the NSPS, state law or regulation, or a permit or approval, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3, and 5.1.4, ExxonMobil may conduct: (1) either a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") once every three (3) years; and (2) a Cylinder Gas Audit ("CGA") each calendar

quarter in which a RAA or RATA is not performed. The Parties agree that the CEMS may need to be moved and reinstalled because of the installation of control equipment, and that once moved it will need to be re-calibrated and re-certified.

C. <u>SO_2 EMISSIONS REDUCTIONS FROM THE FCCUs</u>.

22. **<u>General</u>.** ExxonMobil shall implement a program to reduce SO_2 emissions from the FCCUs at the refineries listed in Subsection V.A, as specified below. Pursuant to Subsection V.Q of this Consent Decree, ExxonMobil shall apply for federally-enforceable permits that incorporate the lower SO_2 emission limits established by this Subsection. ExxonMobil will monitor compliance with the emission limits through the use of CEMS, as specified by this Subsection V.C.

23. **<u>SO_2 Emissions Control for Baytown FCCU 2</u>.**

a. <u>SO_2 Control System</u>. ExxonMobil presently intends to control SO_2 emissions from Baytown FCCU 2 by upgrading and operating its existing WGS.

b. <u>Final SO_2 Limits</u>. By no later than December 31, 2009, ExxonMobil shall comply with SO_2 emission limits of 25 ppmvd at 0% O_2 on a 365-day rolling average basis and 50 ppmvd at 0% O_2 on a 7-day rolling average basis at Baytown FCCU 2.

24. **<u>SO_2 Emissions Control for Baytown FCCU 3</u>.**

a. <u>SO_2 Control System</u>. ExxonMobil presently intends to control SO_2 emissions from Baytown FCCU 3 by operating its existing WGS.

b. <u>Final SO_2 Limits</u>. By no later than the Entry Date, ExxonMobil shall comply with SO_2 emission limits of 25 ppmvd at 0% O_2 on a 365-day rolling average basis and 50 ppmvd at 0% O_2 on a 7-day rolling average basis at Baytown FCCU 3.

25. **<u>SO_2 Emissions Control for the Baton Rouge FCCUs</u>.**

a. <u>SO_2 Control System</u>. ExxonMobil presently intends to control SO_2 emissions from the Baton Rouge FCCUs by: (i) operating its existing WGS; and (ii) taking other steps to reduce SO_2 (which may include, but are not limited to, use of SO_2 Reducing Catalyst Additive) during planned routine maintenance on the Baton Rouge WGS.

b. <u>Final SO_2 Limits</u>. By no later than the January 1, 2006, ExxonMobil shall comply with SO_2 emission limits of 35 ppmvd at 0% O_2 on a 365-day rolling average basis and 70 ppmvd at 0% O_2 on a 7-day rolling average basis at the Baton Rouge FCCUs.

26. **<u>SO_2 Emissions Control for the Beaumont FCCU</u>.**

a. <u>SO_2 Control System</u>. ExxonMobil presently intends to control SO_2 emissions from the Beaumont FCCU by operating its existing WGS.

b. <u>Final SO_2 Limits</u>. By no later than the Entry Date, ExxonMobil shall comply with SO_2 emission limits of 25 ppmvd at 0% O_2 on a 365-day rolling average basis and 50 ppmvd at 0% O_2 on a 7-day rolling average basis at the Beaumont FCCU.

27. **<u>SO_2 Emissions Control for the Joliet FCCU</u>.**

a. <u>SO_2 Control System</u>. ExxonMobil presently intends to control SO_2 emissions from the Joliet FCCU by installing and operating a WGS.

b. <u>Final SO_2 Limits</u>. By no later than December 31, 2008, ExxonMobil shall comply with SO_2 emission limits of 25 ppmvd at 0% O_2 on a 365-day rolling average basis and 50 ppmvd at 0% O_2 on a 7-day rolling average basis at the Joliet FCCU.

28. **<u>SO_2 Emissions Control for the Torrance FCCU</u>.**

a. <u>SO_2 Control System</u>. ExxonMobil presently intends to control SO_2 emissions from the Torrance FCCU by using low sulfur feed in the FCCU.

b. Final SO_2 Limits. By no later than the Entry Date, ExxonMobil shall comply with SO_2 emission limits of 25 ppmvd at 0% O_2 on a 365-day rolling average basis and 50 ppmvd at 0% O_2 on a 7-day rolling average basis at the Torrance FCCU.

29. **SO_2 Emissions Control for the Billings FCCU.**

a. SO_2 Control System. ExxonMobil presently intends to control SO_2 emissions from the Billings FCCU by: (i) converting the FCCU to Full Burn Operation; and (ii) implementing a special two-step protocol using SO_2 Reducing Catalyst Additives, as summarized below.

(1) Step 1. Step 1 of the protocol will commence shortly after the Entry Date. Step 1 will require a performance of a short-term trial to identify the commercially-available catalyst additive that achieves the greatest SO_2 reduction at the Required Addition Rate. Once the best-performing additive is identified, ExxonMobil shall use that additive at the Required Addition Rate whenever the unit is operated, until Step 2 of the protocol.

(2) Step 2. Step 2 of the protocol will commence several years after the Entry Date. Step 2 will require a performance of another short-term trial to identify the future-generation commercially-available catalyst additive that achieves the greatest SO_2 reduction at the Required Addition Rate. Once the best-performing additive is identified, ExxonMobil shall use that additive at the Required Addition Rate during a defined demonstration period.

(3) Required Addition Rate. For the purpose of this Paragraph 29 and Paragraph 30, the term "Required Addition Rate" shall mean addition of 20.0 Average Weight % of Total Catalyst Added, unless EPA agrees to a lesser weight % addition rate

for a particular SO_2 Reducing Catalyst Additive based on a demonstration by ExxonMobil that a lesser addition rate achieves an equal or greater total reduction in SO_2 emissions from the Billings FCCU. The Average Weight % of Total Catalyst Added shall be calculated based on the Total Catalyst Addition Rate during the two year baseline period from November 2001 to October 2003. As required by this Paragraph 29 and Paragraph 30, ExxonMobil shall add SO_2 Reducing Catalyst Additive at the Required Addition Rate in a manner that minimizes SO_2 emissions; provided, however, that ExxonMobil shall not be required to use the Additive in a manner that creates a safety problem or impairs unit feed rate, conversion, feed slate or yield selectivity, unless reasonable steps can be taken to eliminate the problem or compensate for such impairment.

b. Final SO_2 Limits. The final long-term and short-term SO_2 limits for the Billings FCCU shall be established by one of two methods, designated as "Option A" and "Option B" below.

(1) Option A. Under Option A, the final long-term and short-term SO_2 limits for the Billings FCCU shall be set pursuant to Subparagraph 30.i based on the results achieved during the demonstration period in Step 2 of the SO_2 Reducing Catalyst Additive protocol. ExxonMobil shall comply with any long-term and short-term Final SO_2 Limits set under Subparagraph 30.i according to the schedule prescribed by Subparagraph 30.i.

(2) Option B. Under Option B, ExxonMobil may, at any time up to and including its proposing emission limits under Subparagraph 30.h, accept and agree to comply immediately with concentration-based SO_2 emission limits of 25 ppmvd on a

365-day rolling average and 50 ppmvd on a 7-day rolling average basis, both at 0% oxygen, for the Billings FCCU. In such circumstances, ExxonMobil shall be absolved of any remaining obligations for the Billings FCCU under Paragraph 30 of this Consent Decree.

30. **Particular Requirements for the Billings FCCU: Conversion to Full Burn Operation and Two-Step SO_2 Reducing Catalyst Additive Program**. Unless and until ExxonMobil selects Option B under Subparagraph 29.b.(2), ExxonMobil shall implement an SO_2 emissions control program for the Billings FCCU as specified by this Paragraph. The program shall include conversion of the Billings FCCU to Full Burn Operation and implementation of a special two-step protocol using SO_2 Reducing Catalyst Additives, as described below.

a. Conversion of Billings FCCU to Full Burn Operation. By no later than 30 days after the Entry Date, ExxonMobil shall convert the Billings FCCU to Full Burn Operation.

b. SO_2 Baseline Data for the Billings FCCU. By no later than 210 days after the Entry Date, ExxonMobil shall submit to EPA and the Applicable Co-Plaintiff a report on the baseline period beginning 60 days after the Entry Date and ending 180 days after the Entry Date. During that baseline period, the FCCU shall be operated in Full Burn Operation mode, without use of SO_2 Reducing Catalyst Additives. The Baseline Data Report shall include all relevant SO_2 and O_2 CEMS data and all other data set forth in Appendix H.

c. Identification and Selection of SO_2 Reducing Catalyst Additives for Trial Use and Trial Procedures. By the following dates, ExxonMobil shall select and submit for EPA approval a written plan for use of at least three commercially available SO_2 Reducing Catalyst Additives that ExxonMobil proposes to use for short-term trials at the Billings FCCU.

No later than 255 Days after the Entry Date	for the Step 1 trials of current-generation SO_2 Reducing Catalyst Additives
No later than January 15, 2010	for the Step 2 trials of future-generation SO_2 Reducing Catalyst Additives

In the plan for each set of short-term trials, ExxonMobil shall describe, in detail, the trial procedures to be used, including but not limited to: (i) the amount of additive to be baseloaded into the regenerator; (ii) the method of additive loading; and (iii) the expected timing and duration of the trial. Each such plan shall also propose use of at least three specific SO_2 Reducing Catalyst Additives that are likely to perform the best at reducing SO_2 emissions in the FCCU. EPA will base its approval or disapproval of the SO_2 Reducing Catalyst Additives on its assessment of the performance of the proposed Additives in other FCCUs and the similarity of those FCCUs to ExxonMobil's Billings FCCU, with the objective of testing SO_2 Reducing Catalyst Additives likely to have the best performance in reducing SO_2 emissions. If EPA objects to one or more of the proposed SO_2 Reducing Catalyst Additives, or if EPA objects to any other aspect of ExxonMobil's plan, then EPA will explain the basis of its objections in writing. In the event that ExxonMobil submits less than three approvable Additives, EPA shall identify and by that identification approve the use of other SO_2 Reducing Catalyst Additives by ExxonMobil.

d. Performance of the Short-Term Trials. In each Step of the protocol, ExxonMobil shall perform a set of short-term trials in accordance with the plan approved by EPA under Subparagraph 30.c. ExxonMobil shall commence and complete the short-term trials in accordance with the following schedule:

For the Step 1 trials of current-generation SO_2 Reducing Catalyst Additives:	
Commencement Date	No later than 300 days after the Entry Date
Completion Date	No later than 480 days after the Entry Date

For the Step 2 trials of future-generation SO_2 Reducing Catalyst Additives:	
Commencement Date	No later than March 1, 2010
Completion Date	No later than October 1, 2010

e. Reports on the Short-Term Trials. For each Step of the protocol, ExxonMobil shall submit a written report to EPA describing the performance of each SO_2 Reducing Catalyst Additive that was tested in the short-term trials.

(1) In each Trials Report, ExxonMobil shall summarize the results of the trials and shall provide all relevant SO_2 and O_2 CEMS data and all other data set forth in Appendix H. Each Trials Report shall also summarize any safety problems or impairments of unit feed rate, conversion, feed slate, or yield selectivity observed in the trials, and all steps that were taken to attempt to eliminate the problems or compensate for such impairments.

(2) In each Trials Report, ExxonMobil shall identify the Additive that achieved the lowest SO_2 concentration, corrected to 0% O_2, when averaged over the entire trial period and the additive that reduced emissions the most from a predicted uncontrolled baseline during the trials (the "Best-Performing Additive"). If EPA determines that another Additive tested in the trials was the Best-Performing Additive in the trials, then EPA, after consultation with the Applicable Co-Plaintiff, will so notify ExxonMobil and ExxonMobil shall treat that Additive as the Best-Performing Additive and use it at the specified addition rate in the Step 1 Interim Reduction Period (under Subparagraph 30.f) or the Step 2 Demonstration (under Subparagraph 30.g).

(3) ExxonMobil shall submit the Trials Reports in accordance with the following schedule:

<u>For the Step 1 trials of current-generation SO_2 Reducing Catalyst Additives:</u>

Report Due Date	No later than 540 days after the Entry Date

<u>For the Step 2 trials of future-generation SO_2 Reducing Catalyst Additives:</u>

Report Due Date	No later than December 1, 2010

f. <u>Step 1 Interim Reduction Period</u>. By no later than 585 days after the Entry Date, ExxonMobil shall commence and continue use of the Best-Performing Additive for Step 1 at the Required Addition Rate; <u>provided</u>, <u>however</u>, that ExxonMobil shall not be required to operate the FCCU or use the Additive in a manner that creates a safety problem or impairs unit feed rate, conversion, feed slate, or yield selectivity, unless reasonable steps can be taken to eliminate the problem or compensate for such impairment. ExxonMobil shall continue using the Best-Performing Additive at the Required Addition Rate until commencement of the Step 2 trials under Subparagraph 30.d.

g. <u>Step 2 Demonstration</u>. ExxonMobil shall commence and complete a demonstration of the Best-Performing Additive for Step 2 in accordance with the following schedule:

Commencement Date	No later than January 15, 2011
Completion Date	No later than January 15, 2012

During the Step 2 demonstration, ExxonMobil shall use the Best-Performing Additive for Step 2 at the Required Addition Rate and shall operate the FCCU and the CO boiler in a manner that minimizes SO2 emissions; <u>provided</u>, <u>however</u>, that ExxonMobil shall not be required to operate the FCCU or use the Additive in a manner that creates a safety problem or impairs unit feed rate, conversion, feed slate, or yield selectivity, unless reasonable steps can be taken to eliminate the problem or compensate for such impairment. Even after completion of the demonstration, ExxonMobil shall continue using the Best-Performing Additive at the Required Addition Rate until ExxonMobil begins complying with proposed and final SO_2 emission limits under Subparagraphs 30.h and 30.i.

h. Step 2 Demonstration Report. By no later than March 15, 2012, ExxonMobil will submit a written report to EPA on the results of the Step 2 Demonstration. In the Step 2 Demonstration Report, ExxonMobil shall summarize the results of the demonstration and shall provide all relevant SO_2 and O_2 CEMS data and all other data set forth in Appendix H. In the Step 2 Demonstration Report, ExxonMobil shall propose a long-term (i.e., 365-day rolling average) and short-term (i.e., 7-day rolling average) concentration-based (ppmvd) SO_2 emission limits, both as measured at 0% O_2, for the Billings FCCU. ExxonMobil shall comply with the emission limits it proposes for the Billings FCCU beginning immediately upon submission of the Step 2 Demonstration Report. ExxonMobil shall continue to comply with these limits unless and until ExxonMobil is required to comply with the emissions limits set by EPA pursuant to Subparagraph 30.i.

i. Establishment of Final Limits for the Billings FCCU. EPA will use the data collected during the Step 2 Demonstration Period, as well as all other available and relevant information, to establish long-term and short-term final limits for SO_2 emissions from the Billings FCCU. EPA will establish 365-day rolling average and 7-day rolling average concentration-based (ppmvd) SO_2 emission limits, corrected to 0% oxygen, which limits can be met with a reasonable certainty of compliance. Such limits may be the same as the limits proposed by ExxonMobil in accordance with Subparagraph 30.h. ExxonMobil may propose, and EPA may establish, alternative emissions limits to be applicable during alternative operating scenarios. EPA will determine the limits based on: (i) the level of performance during the Step 2 Demonstration Period; (ii) a reasonable certainty of compliance; and (iii) any other available and relevant information. EPA will notify ExxonMobil of its determination of the long-term and short-term concentration-based SO_2 emissions limits. ExxonMobil shall immediately (or within thirty (30) days, if EPA's limit is more stringent than the limit proposed by ExxonMobil) operate the FCCU so as to comply with the EPA-established emission limits. Disputes regarding the appropriate emission limits shall be resolved in accordance with the dispute resolution provisions of this Decree; provided, however, that during the period of dispute resolution, ExxonMobil shall use Additive in the manner and amount applicable during the Step 2 Demonstration Period (in lieu of meeting the EPA-established limits).

31. **Startup, Shutdown, and Malfunction**. SO_2 emissions (i) caused by or attributable to the startup or shutdown of an FCCU that is not controlled by a WGS and/or (ii) during periods of Malfunction of the FCCU or Malfunction of the relevant FCCU's WGS or SO_2 Reducing Catalyst Additive system will not be used in determining compliance with the short-term (7-day) SO_2 emission limits established pursuant to Subparagraphs 23.b, 24.b, 25.b, 26.b, 27.b, 28.b, and 29.b, provided that during such periods ExxonMobil implements good air pollution control practices to minimize SO_2 emissions. Nothing in this Paragraph shall be construed to relieve ExxonMobil of any obligation under any federal, state, or local law, regulation, or permit to report emissions during periods of startup, shutdown, or Malfunction, or to document the occurrence and/or cause of a startup, shutdown, or Malfunction event. Emissions during any such period of startup, shutdown, or Malfunction shall either be: (i) monitored with CEMS as provided by Paragraph 32; or (ii) monitored in accordance with an

Alternative Monitoring Plan approved by EPA if it is necessary to bypass the FCCU's main stack during the particular period of startup, shutdown, or Malfunction.

32. **Demonstrating Compliance with FCCU SO_2 Emission Limits for the FCCUs.** By no later than the dates set out in Appendix N, ExxonMobil shall use SO_2 and O_2 CEMS at each of the FCCUs at the refineries listed in Subsection V.A to monitor performance and to report compliance with the terms and conditions of this Subsection V.C relating to SO_2 emissions from the FCCUs. As permitted by Paragraph 31, emissions during certain periods may be monitored in accordance with an Alternative Monitoring Plan approved by EPA. ExxonMobil shall make emissions monitoring data available to EPA as soon as practicable following an EPA request for such data. For the Baton Rouge FCCUs, the Baytown FCCUs, the Beaumont FCCU, and the Torrance FCCU, unless compliance 40 C.F.R. Part 60, Appendix F is otherwise required by the NSPS, state law or regulation, or a permit or approval, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3, and 5.1.4, ExxonMobil may conduct: (1) either a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") once every three (3) years; and (2) a Cylinder Gas Audit ("CGA") each calendar quarter in which a RAA or RATA is not performed. The Parties agree that the CEMS may need to be moved and reinstalled because of the installation of control equipment, and that once moved it will need to be re-calibrated and re-certified.

D. **PARTICULATE MATTER EMISSIONS REDUCTIONS FROM THE FCCUs.**

33. **General**. ExxonMobil shall implement a program to reduce PM emissions from the FCCUs at the refineries listed in Subsection V.A, as specified below. Pursuant to Subsection V.Q of this Consent Decree, ExxonMobil shall apply for federally-enforceable permits that incorporate the lower PM emission limits established by this Subsection. ExxonMobil will monitor compliance with the emission limits as specified by this Subsection V.D.

34. **Emission Limits for PM.**

a. Consistent with the NSPS regulations at 40 C.F.R., Part 60, Subpart J, ExxonMobil shall comply with an emission limit of 1.0 pounds of PM per 1000 pounds of coke burned for the FCCUs listed below by the dates listed below:

FCCU	PM Emission Limit Compliance Date
Baytown FCCU 2	December 31, 2009
Baytown FCCU 3	Consent Decree Entry Date
Beaumont FCCU	Consent Decree Entry Date
Joliet FCCU	Consent Decree Entry Date
Torrance FCCU	Consent Decree Entry Date

b. By no later than December 31, 2006, ExxonMobil shall: (i) install and commence operation of new third-stage cyclones on the Billings FCCU; and, thereafter (ii) complete a performance test to assess PM emissions from the Billings FCCU under "turn down" conditions based on the average of three runs in a test performed in accordance with Method 5B or 5F. If PM emissions during that performance test are less than 1.0 pound of PM per 1000 pounds of coke burned, then the Billings FCCU shall comply with an emission limit of 1.0 pounds of PM per 1000 pounds of coke burned as of December 31, 2006, consistent with the NSPS regulations at 40 C.F.R., Part 60, Subpart J. If PM emissions during that performance test are greater than or equal to 1.0 pound of PM per 1000 pounds of coke burned, then ExxonMobil shall take additional steps to reduce PM emissions from the Billings FCCU and shall comply with an emission limit of 1.0 pounds of PM per 1000 pounds of coke burned as of December 31, 2008, consistent with the NSPS regulations at 40 C.F.R., Part 60, Subpart J. By no later than December 31, 2006, ExxonMobil shall provide EPA and the Applicable Co-Plaintiff a written report that summarizes the results of the performance test and either: (i) indicates that ExxonMobil will comply with the emission limit by December 31, 2006 under this Paragraph; or (ii) indicates that ExxonMobil will comply with the emission limit by December 31, 2008 and summarizes the additional steps that ExxonMobil intends to take to comply with the emission limit under this Paragraph.

35. **NSR Emission Limits for PM**. At any time during the term of the Consent Decree, ExxonMobil may accept a Final PM Limit of 0.5 pounds of PM per 1000 pounds of coke burned based on the average of three runs in a test performed in accordance with Method 5B or 5F. Upon accepting such limit: (i) ExxonMobil's liability for certain potential NSR violations for PM emissions from the relevant FCCU shall be resolved pursuant to Paragraph 238 of this Consent Decree; and (ii) ExxonMobil, in accordance with Paragraph 142, shall apply for a federally-enforceable permit that shall incorporate this Final PM Limit.

36. **Startup, Shutdown, and Malfunction**. PM emissions (i) caused by or attributable to the startup or shutdown of an FCCU that is not controlled by a WGS and/or (ii) during periods of Malfunction of the FCCU or Malfunction of the relevant FCCU's WGS, third-stage cyclones or electrostatic precipitator will not be used in determining compliance with any PM emission limits established by Paragraphs 34 and 35, provided that during such periods ExxonMobil implements good air pollution control practices to minimize PM emissions. Nothing in this Paragraph shall be construed to relieve ExxonMobil of any obligation under any

federal, state, or local law, regulation, or permit to report emissions during periods of startup, shutdown, or Malfunction, or to document the occurrence and/or cause of a startup, shutdown, or Malfunction event.

37. **PM Testing.** ExxonMobil shall follow the test protocol specified in 40 C.F.R. § 60.106(b)(2) using EPA Reference Method 5B or 5F to measure PM emissions from each of the FCCUs identified in Paragraph 34. ExxonMobil shall propose and submit the test protocol to EPA for approval, with a copy to the Applicable Co-Plaintiff, by no later than three (3) months after a PM limit becomes effective. ExxonMobil shall conduct the first test no later than three (3) months after EPA approves the test protocol. ExxonMobil shall conduct annual PM tests on each of the FCCUs identified in Paragraph 34 and shall submit the results in the first Semi-Annual Report due under Section IX that is at least three (3) months after the test. Upon demonstrating through at least three (3) annual tests that the PM limits are not being exceeded at a particular FCCU, ExxonMobil may request EPA approval to conduct tests less frequently than annually. Such approval will not be unreasonably withheld. Nothing in this Consent Decree shall limit the authority of EPA or an Applicable Co-Plaintiff to require additional tests under any statutory or regulatory provision or under any permit.

E. CARBON MONOXIDE EMISSIONS REDUCTIONS FROM THE FCCUs.

38. **General.** ExxonMobil shall implement a program to reduce CO emissions from the FCCUs at the refineries listed in Subsection V.A, as specified below. Pursuant to Subsection V.Q of this Consent Decree, ExxonMobil shall apply for federally-enforceable permits that incorporate the lower CO emission limits. ExxonMobil will monitor compliance with the emission limits with CEMS, as specified by this Subsection V.E.

39. **<u>Emission Limits for CO</u>.** Consistent with the NSPS regulations at 40 C.F.R., Part 60, Subpart J, ExxonMobil shall comply with an emission limit of 500 ppmvd CO corrected to 0% O_2 on a 1-hour average basis for the FCCUs listed below by the dates listed below:

<u>FCCU</u>	**<u>CO Emission Limit Compliance Date</u>**
Baytown FCCU 2	Consent Decree Entry Date
Baytown FCCU 3	Consent Decree Entry Date
Beaumont FCCU	Consent Decree Entry Date
Billings FCCU	Consent Decree Entry Date
Joliet FCCU	Consent Decree Entry Date
Torrance FCCU	Consent Decree Entry Date

40. **<u>NSR Emission Limits for CO</u>**. At any time during the term of the Consent Decree, ExxonMobil may accept the following Final CO Limits for a FCCU:

Long-term limit: 150 ppmvd CO on a 365-day rolling average basis at 0% O_2

Short-term limit: 250 ppmvd CO on a 24-hour rolling average basis at 0% O_2

Upon accepting such Final CO Limits for a FCCU: (i) ExxonMobil's liability for certain potential NSR violations for CO emissions from the relevant FCCU shall be resolved pursuant to Paragraph 239 of this Consent Decree; and (ii) ExxonMobil shall, in accordance with Paragraph 142, apply for a federally-enforceable permit that incorporates such limits.

41. **<u>Startup, Shutdown, and Malfunction</u>.** CO emissions (i) caused by or attributable to the startup, shutdown, or Malfunction of an FCCU listed in Subsection V.A and/or (ii) during periods of Malfunction of the relevant FCCU's CO control system will not be used in determining compliance with any short-term (<u>i.e.</u>, 1-hour and/or 24-hour) CO emission limit established pursuant to Paragraph 39 or 40, provided that during such periods ExxonMobil implements good air pollution control practices to minimize CO emissions. Nothing in this Paragraph shall be construed to relieve ExxonMobil of any obligation under any federal, state, or local law, regulation, or permit to report emissions during periods of startup, shutdown, or

Malfunction, or to document the occurrence and/or cause of a startup, shutdown, or Malfunction event. Emissions during any such period of startup, shutdown, or Malfunction shall either be: (i) monitored with CEMS as provided by Paragraph 42; or (ii) monitored in accordance with an Alternative Monitoring Plan approved by EPA if it is necessary to bypass the FCCU's main stack during the particular period of startup, shutdown, or Malfunction.

42. **Demonstrating Compliance with CO Emissions Limits.** By no later than the dates set out in Appendix N, ExxonMobil shall use CO and O_2 CEMS at each of the FCCUs at the refineries listed in Paragraph 39 to monitor emissions and to report compliance with the terms and conditions of this Subsection V.E relating to CO emissions from the FCCUs. As permitted by Paragraph 41, emissions during certain periods may be monitored in accordance with an Alternative Monitoring Plan approved by EPA. ExxonMobil shall make emissions monitoring data available to EPA as soon as practicable following an EPA request for such data. For the Baton Rouge FCCUs, the Baytown FCCUs, the Beaumont FCCU, the Billings FCCU, and the Torrance FCCU, unless compliance with 40 C.F.R. Part 60, Appendix F is otherwise required by the NSPS, state law or regulation, or a permit or approval, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3, and 5.1.4, ExxonMobil may conduct: (1) either a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") once every three (3) years; and (2) a Cylinder Gas Audit ("CGA") each calendar quarter in which a RAA or RATA is not performed. The Parties agree that the CEMS may need to be moved and reinstalled because of the installation of control equipment, and that once moved it will need to be re-calibrated and re-certified.

F. NSPS APPLICABILITY TO THE FCCU CATALYST REGENERATORS.

43. **NSPS Applicability and Compliance.** Each of the FCCU catalyst regenerators for the FCCUs at the refineries listed in Subsection V.A shall be an "affected facility," as that term is used in 40 C.F.R. Part 60, Subparts A and J, with respect to the pollutants specified for such FCCU catalyst regenerators in the following Subparagraphs, and shall be subject to all of the applicable requirements of NSPS Subparts A and J, by the dates set forth below.

a. Sulfur Oxides. ExxonMobil shall comply with the requirements of NSPS Subparts A and J for the following FCCU catalyst regenerators for SO_2 by the following dates:

FCCU	NSPS Effective Date for SO_2
Baton Rouge PCLA 2	January 1, 2006
Baton Rouge PCLA 3	January 1, 2006
Baytown FCCU 2	December 31, 2006
Baytown FCCU 3	Consent Decree Entry Date
Beaumont FCCU	Consent Decree Entry Date
Joliet FCCU	December 31, 2008
Torrance FCCU	Consent Decree Entry Date

b. Particulate Matter.

(1) ExxonMobil shall comply with the requirements of NSPS Subparts A and J for the following FCCU catalyst regenerators for PM by the following dates:

FCCU	NSPS Effective Date for PM
Baytown FCCU 2	December 31, 2009
Baytown FCCU 3	Consent Decree Entry Date
Beaumont FCCU	Consent Decree Entry Date
Joliet FCCU	Consent Decree Entry Date
Torrance FCCU	Consent Decree Entry Date

(2) ExxonMobil shall comply with the requirements of NSPS Subparts A and J for the Billings FCCU catalyst regenerator for PM: (i) by no later than December 31, 2006, if the results of performance tests conducted pursuant to Subparagraph 34.b are such that compliance with an emission limit of 1.0 pounds PM per

1000 pounds of coke burned is required by that date; or (ii) by no later than December 31, 2008, if the results of performance tests conducted pursuant to Subparagraph 34.b are such that compliance with an emission limit of 1.0 pounds PM per 1000 pounds of coke burned is required by that date.

c. Carbon Monoxide. ExxonMobil shall comply with the requirements of NSPS Subparts A and J for the following FCCU catalyst regenerators for CO by the following dates:

FCCU	**NSPS Effective Date for CO**
Baytown FCCU 2	Consent Decree Entry Date
Baytown FCCU 3	Consent Decree Entry Date
Beaumont FCCU	Consent Decree Entry Date
Billings FCCU	18 months after Consent Decree Entry Date
Joliet FCCU	18 months after Consent Decree Entry Date
Torrance FCCU	Consent Decree Entry Date

d. Opacity. ExxonMobil shall comply with the requirements of NSPS Subparts A and J for the following FCCU catalyst regenerators for opacity by the following dates:

FCCU	**NSPS Effective Date for Opacity**
Baytown FCCU 2	Submit AMP six months after Entry Date
Baytown FCCU 3	Submit AMP six months after Entry Date
Beaumont FCCU	AMP pending
Billings FCCU	December 31, 2006
Joliet FCCU	Consent Decree Entry Date
Torrance FCCU	Consent Decree Entry Date

Where this Subparagraph specifies an alternative monitoring plan ("AMP") submittal date (rather than a final NSPS Subpart A and J compliance date), ExxonMobil shall submit to EPA a timely and complete AMP application by the date(s) specified. Where this Subparagraph indicates that an AMP is pending, ExxonMobil has already submitted an AMP application to EPA. If an AMP is not approved, ExxonMobil shall submit to EPA for approval a plan for complying with the monitoring requirements of NSPS Subparts A and J for the particular equipment within ninety (90) days of receiving notice of the disapproval. The equipment will become an affected facility when ExxonMobil receives EPA's approval of the relevant AMP. A plan for complying with the monitoring requirements of NSPS Subparts A and J may include a revised AMP application, physical or operational changes to the equipment, or additional or different monitoring.

e. For all periods of operation, ExxonMobil shall ensure that each FCCU catalyst regenerator complies with the applicable emissions limitations imposed by NSPS Subpart J, as specified by the preceding Subparagraphs, except during periods of startup, shutdown, or Malfunction, as defined by 40 C.F.R. § 60.2. At all times, including periods of startup, shutdown, and Malfunction, ExxonMobil shall, to the extent practicable, maintain and operate each FCCU catalyst regenerator and any associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

f. For FCCU catalyst regenerators that become affected facilities under NSPS Subparts A and J pursuant to this Paragraph 43. Entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for FCCUs shall satisfy the notice requirements of 40 C.F.R. 60.7(a) and the initial performance test requirements of 40 C.F.R. § 60.8(a).

44. **Particular Requirements Applicable to the Baton Rouge FCCUs.**

a. Compliance with NSPS SO_2 Emission Limitations. By no later than January 1, 2006, ExxonMobil shall ensure that the Baton Rouge FCCUs' catalyst regenerators comply with the applicable NSPS SO_2 emission limitations at all times, except during periods of startup, shutdown or Malfunction as defined by 40 C.F.R. § 60.2. Specifically, ExxonMobil shall: (i) comply with the emission limitation established by 40 C.F.R. 60.104(b)(1), except during any period of planned routine maintenance on the Baton Rouge WGS approved in accordance with 40 C.F.R. 63.1575(j); and (ii) comply with one of the alternative emission limitations established by 40 C.F.R. 60.104(b)(2) or (b)(3) during any period of planned routine maintenance on the Baton Rouge WGS approved in accordance with 40 C.F.R. 63.1575(j). Compliance with the provisions of this Subparagraph 44.a shall constitute compliance with the emission limitations requirements of 40 C.F.R. § 60.104(b).

b. MACT Standard Compliance. ExxonMobil shall ensure that each of the Baton Rouge FCCUs complies with all applicable requirements of the Maximum Achievable Control Technology standard for catalytic cracking units, as set forth at 40 C.F.R. Part 63, Subparts A and UUU (the "MACT Standard") including, but not limited to: (i) the emission limitations imposed by 40 C.F.R. §§ 63.1564(a) and 63.1565(a); (ii) the requirement to prepare and operate at all times in compliance with an operation, maintenance, and monitoring plan (an "OMM Plan"), as defined in 40 C.F.R. § 63.1574(f), and a startup, shutdown, and malfunction plan (an "SSM Plan"), as defined in 40 C.F.R. § 63.6(e)(3); and (iii) the provisions of 40 C.F.R. § 63.1575(j) relating to planned routine maintenance on the Baton Rouge WGS.

c. OMM Plan Requirements. The OMM Plan(s) for the Baton Rouge FCCUs shall include a schedule and procedures for planned routine maintenance on the Baton Rouge WGS. The schedule and procedures shall be consistent with good air pollution control practices for minimizing emissions to the extent practicable, and shall incorporate the requirements specified by the following Subparagraphs.

(1) The OMM Plan(s) shall establish schedules and procedures for minimizing criteria pollutant and hazardous air pollutant emissions associated with

planned routine maintenance on the Baton Rouge WGS, to the extent practicable. The OMM Plan shall specifically require that ExxonMobil: (i) minimize the duration of each planned routine maintenance period; (ii) maximize WGS run length between planned routine maintenance periods; (iii) coordinate planned routine maintenance on the WGS with scheduled turnarounds of at least one of the Baton Rouge FCCUs; and (iv) seek and obtain the applicable permitting authority's advance approval of each planned routine maintenance period under the requirements imposed by 40 C.F.R. § 63.1575(j).

(2) The OMM Plan requirements specified by Subparagraph 44.c.(1) shall apply only to planned routine maintenance on the Baton Rouge WGS, and shall not apply to any unplanned shutdown or malfunction. Among other things, as required by Subparagraph 44.b, the SSM Plan for the Baton Rouge FCCUs shall separately address periods of unplanned shutdown or malfunction, including ExxonMobil's duty to operate and maintain the affected source (including associated air pollution control equipment and monitoring equipment) in a manner consistent with good air pollution control practices for minimizing emissions to the extent practicable.

d. Emissions of NOx and SO_2 from the Baton Rouge FCCUs during periods of planned routine maintenance on the Baton Rouge WGS shall not be used in determining compliance with the short-term NOx and SO_2 emission limits established for the Baton Rouge FCCUs under Subparagraphs 13.b.(2) and 25.b of this Consent Decree, provided that ExxonMobil operates the units in a manner consistent with good air pollution control practices during such periods. Emissions during such periods of planned routine maintenance on the Baton Rouge WGS shall either be: (i) monitored with CEMS as provided by Paragraphs 21 and 32; or (ii) monitored in accordance with an Alternative Monitoring Plan approved by EPA.

G. **NOx EMISSIONS REDUCTIONS FROM COMBUSTION UNITS**.

45. **General.** ExxonMobil shall implement a program to reduce NOx emissions from Combustion Units identified in Appendix A through the installation of NOx controls or the shutdown of certain units and by the acceptance of permit limits on the units controlled to meet the requirements of Paragraphs 47 and 51. ExxonMobil will monitor compliance with the emission limits through the use of CEMS, a predictive emissions monitoring system ("PEMS"), or stack tests as described in more detail below.

46. **Identification of Qualifying Controls.** ExxonMobil shall select one or any combination of the following "Qualifying Controls" to satisfy the requirements of Paragraphs 47 and 51:

i. selective catalytic reduction or selective non-catalytic reduction;

ii. Current Generation or Next Generation Ultra-Low NOx Burners;

iii. other technologies which ExxonMobil demonstrates to EPA's satisfaction should reduce NOx emissions to 0.040 pounds of NOx per mmBTU heat input or lower; or

iv. permanent shutdown of a Combustion Unit with surrender of its operating permit; provided, however, that to the extent that the emissions reductions resulting from the permanent shutdown are used to satisfy the requirements of Paragraphs 47, 50, and 51, those reductions may not be used as reductions for the construction of new units or the modification of existing units permitted collectively as a single project with the shutdown, notwithstanding the provisions of Subparagraph 150.iv.

47. **Installation of Qualifying Controls.**

a. On or before September 30, 2010, ExxonMobil shall use Qualifying Controls to reduce NOx emissions from the Combustion Units listed in Appendix A by at least 4750 tons per year, so as to satisfy the following inequality:

$$\sum_{i=1}^{n}\left[\left(E_{actual}\right)_i - \left(E_{allowable}\right)_i\right] \geq \text{ 4750 tons per year}$$

Where:

$(E_{allowable})_i$	=	[(The permitted allowable pounds of NOx per million BTU for Combustion Unit i)/(2000 pounds per ton)] x [(the lower of permitted or maximum heat input rate capacity in million BTU per hour for Combustion Unit i) x (the lower of 8760 or permitted hours per year)];
$(E_{Actual})_i$	=	The tons of NOx per year prior actual emissions as listed in Appendix A for Combustion Unit i (unless prior actual emissions exceed allowable emissions, then use allowable); and
n	=	The number of Combustion Units with Qualifying Controls from those listed in Appendix A that are selected by ExxonMobil to satisfy the requirements of the equation set forth in this Paragraph 47.

Permit limits established to implement this Paragraph may use a 365-day rolling average for Combustion Units that use a CEMS or PEMS to monitor compliance, and for Combustion Units that do not use a CEMS or PEMS, the permit limits averaging period must be no longer than the averaging period of the reference test method.

b. For the following four sets of Combustion Units:

i. Baton Rouge Refinery Combustion Units F-2 and F-3 (at Refinery Units PCLA-2 and PCLA-3);

ii. Baytown Refinery Combustion Units GTG-38, GTG-41, GTG-42, GTG-43, GTG-44, and GTG-45 (all at Refinery Units BH-6 and BH-7);

iii. Baytown Refinery Combustion Units F-801 and F-802 (at Refinery Unit PS-8); and

iv. Beaumont Refinery Boiler 33 and Boiler 34 (at Power Plant 3).

ExxonMobil may use the combined permitted heat input capacity for the set of Combustion Units in the inequality in Subparagraph 47.a, provided that each Combustion Unit in the set has an identical emission limit (in lbs/mmBTU). The emission limit and combined permitted heat input capacity for the set may be used in the inequality as if the set of Combustion Units were one unit.

48. **Baseline Information.** Appendix A to this Consent Decree provides the following information for each Combustion Unit:

i. the maximum physical heat input capacity or, if less, the allowable heat input capacity in mmBtu/hr (HHV);

ii. the baseline emission rate for the agreed-upon baseline years in pounds of NOx per mmBtu heat input (HHV) and tons per year of actual emissions;

iii. the type of data used to derive the emission estimate (i.e., emission factor, stack test, or CEMS data); and,

iv. the utilization rate in annual average mmBtu/hr (HHV) for the baseline years.

49. **NOx Control Plan**. ExxonMobil shall submit a detailed NOx control plan (the "NOx Control Plan") to EPA for review and comment by no later than 90 days after the Entry Date, with annual updates (covering the prior calendar year as determined at calendar year end) with the first report submitted pursuant to Section IX (Recordkeeping and Reporting) following the passage of each calendar year until termination of the Consent Decree or until the reductions required by Paragraph 47 are achieved, whichever occurs first. The NOx Control Plan and its annual updates shall describe the achieved (as determined at calendar year end) and anticipated progress of the NOx emissions reductions program for Combustion Units and shall contain the following information for each Combustion Unit greater than 40 mmBtu/hr that ExxonMobil plans to use to satisfy the requirements of Paragraphs 47, 50, and 51:

i. All of the information in Appendix A;

ii. Identification of the type of Qualifying Controls installed or planned with date installed or planned (including identification of the Combustion Unit to be permanently shut down);

iii. To the extent limits exist, the allowable NOx emission rates (in lbs/mmBtu (HHV)), with averaging period) and allowable heat input rate (in mmBtu/hr (HHV)) obtained or planned with dates obtained or planned;

iv. The results of emissions tests and annual average CEMS data (reported in ppmvd corrected to 3% O_2, and in lbs/mmBtu) conducted pursuant to Paragraph 53 and tons per year; and

v. The amount in tons per year applied or to be applied toward satisfying Paragraph 47.

Appendix A, the NOx Control Plan, and the annual updates required by this Paragraph shall be for informational purposes only and shall not be used to develop permit requirements or other operating restrictions. ExxonMobil may change any projections, plans, or information (including, but not limited to, which units ExxonMobil plans to control) that is included in the NOx Control Plan or updates by including such changes or updates in its annual reports.

50. **<u>Milestones.</u>**

a. By December 31, 2008, ExxonMobil shall install sufficient Qualifying Controls and have applied for emission limits sufficient to reduce NOx emissions by two-thirds of the NOx emissions reductions required by Paragraph 47. In the first Semi-Annual Report to be submitted under Section IX after December 31, 2008, ExxonMobil shall include a report showing how it satisfied the requirement of this Subparagraph.

b. By December 31, 2009, ExxonMobil shall install sufficient Qualifying Controls and have applied for emission limits sufficient to reduce NOx emissions by 95% of the NOx emissions reductions required by Paragraph 47. In the first Semi-Annual Report to be submitted under Section IX after December 31, 2009, ExxonMobil shall include a report showing how it satisfied the requirement of this Paragraph.

c. Consistent with Paragraph 47, ExxonMobil shall install the remainder of the required Qualifying Controls by no later than September 30, 2010.

51. By no later than September 30, 2010, Combustion Units with Qualifying Controls shall represent at least 30% of the total maximum heat input capacity of all Combustion Units greater than 40 mmBtu/hr (at HHV) located at each of the Covered Refineries. Any Qualifying Controls may be used to satisfy this requirement, regardless of when the Qualifying Controls were installed.

52. Pursuant to Subsection V.Q of this Consent Decree, ExxonMobil shall apply for federally-enforceable permits that incorporate emission limits (in lbs/mmBTU) for Combustion Units required under Paragraph 47, to ensure that the NOx emission reduction requirements imposed by this Subsection V.G shall survive the termination of this Consent Decree.

53. For Combustion Units where Qualifying Controls are installed after the Entry Date, beginning no later than 180 days after installing Qualifying Controls on and commencing operation of a Combustion Unit that will be used to satisfy the requirements of Paragraph 47, ExxonMobil shall monitor such Combustion Unit as follows:

i. For each Combustion Unit with a maximum physical capacity greater than 150 mmBtu/hr (HHV), install or continue to operate a NOx and O_2 CEMS.

ii. For each Combustion Unit with a maximum physical capacity greater than 100 mmBtu/hr (HHV) but less than or equal to 150 mmBtu/hr (HHV), install or continue to operate a NOx and O_2 CEMS, or monitor NOx emissions with a PEMS developed and operated pursuant to the requirements of Appendix B of this Consent Decree.

iii. For each Combustion Unit with a maximum physical capacity of less than or equal to 100 mmBtu/hr (HHV), (a) conduct an initial performance test and any periodic tests that may be required by EPA or by an Applicable Co-Plaintiff under other applicable regulatory authority; or (b) comply with the monitoring requirements described in Subparagraphs 53.i. or 53.ii above. The results of the initial performance testing shall be reported to the EPA and the Applicable Co-Plaintiff within 90 days of completing the test.

ExxonMobil shall use Method 7E to conduct initial performance testing required by Subparagraph 53.iii. Monitoring with a PEMS that is required by this Paragraph shall be conducted in accordance with the requirements of Appendix B. By no later than 90 days after the Entry Date, ExxonMobil shall submit to EPA for review and comment a PEMS Program in accordance with Appendix B. For units that utilize Qualifying Controls as of the Entry Date and which ExxonMobil intends to use to achieve the NOx reductions required by Paragraphs 47 and/or 51, ExxonMobil shall implement the specified monitoring requirements (CEMS, PEMS, stack test) based on the capacity of the Combustion Unit as listed in Appendix A by no later than eighteen (18) months after the Entry Date. For any such unit with a maximum physical capacity of less than or equal to 100 mmBtu/hr (HHV), an additional performance test is not required under this Paragraph if an initial performance test using Method 7E was performed after January 1, 2004 and after the Combustion Unit was equipped with Qualifying Controls.

54. **Demonstrating Compliance through Use of a NOx CEMS.** ExxonMobil shall install, certify, calibrate, maintain, and operate the CEMS required by Paragraph 53 in accordance with 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. For the Baton Rouge Refinery, the Baytown Refinery, the Beaumont Refinery, and the Torrance Refinery, unless Appendix F is otherwise required by the NSPS, state law or regulation, or a permit or approval, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, ExxonMobil may conduct either a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") once every

three (3) years and shall conduct Cylinder Gas Audits ("CGA") each calendar quarter during which a RAA or a RATA is not performed.

55. The requirements of this Subsection V.G do not exempt ExxonMobil from complying with any and all Federal, state, regional, and local requirements that may require technology, equipment, monitoring, or other upgrades based on actions or activities occurring after the Date of Lodging of the Consent Decree, or based upon new or modified regulatory, statutory, or permit requirements. However, nothing in this Subsection V.G is meant to prevent ExxonMobil from using the NOx reductions achieved pursuant to this Section towards future NOx emission reduction requirements except as prohibited under Section VI (Emission Credit Generation) of this Consent Decree. ExxonMobil is not prohibited from using additional emission reductions from Combustion Units that are not required by this Consent Decree for any other purpose as allowed by Paragraph 150.

56. ExxonMobil shall retain records demonstrating installation of Qualifying Controls under Paragraph 47 and monitoring/test data under Paragraph 53 until termination of the Consent Decree. ExxonMobil shall submit such records to EPA upon request.

57. If ExxonMobil transfers ownership of any Covered Refinery before achieving all of the NOx reductions required by Paragraph 47, ExxonMobil shall notify EPA and the Applicable Co-Plaintiff of that transfer and shall submit an allocation to EPA and the Applicable Co-Plaintiff for that Covered Refinery's share of NOx reduction requirements of Paragraph 47 that will apply individually to the transferred refinery after such transfer. If ExxonMobil chooses, such allocation may be zero. Any such allocation shall be memorialized in a Consent Decree modification in accordance with Paragraphs 7 and 269.

H. **<u>SO_2 EMISSIONS REDUCTIONS FROM AND NSPS APPLICABILITY OF HEATERS, BOILERS AND OTHER FUEL GAS COMBUSTION DEVICES</u>**.

58. **<u>General</u>.** ExxonMobil shall undertake measures to limit SO_2 emissions from refinery heaters and boilers and other fuel combustion devices by restricting H_2S in refinery fuel gas and by agreeing not to burn Fuel Oil except as specifically permitted under the provisions of this Subsection V.H. Flaring Devices are not subject to the provisions of this Subsection V.H, but rather are subject to the provisions of Subsections V.J, V.K, and V.L.

59. **<u>NSPS Applicability to Heaters, Boilers and Other Fuel Gas Combustion Devices (Other than Flaring Devices)</u>.**

a. Upon the Entry Date, each heater and boiler that is used to combust refinery fuel gas at any of the Covered Refineries shall be an "affected facility," as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall be subject to, and comply with the requirements of NSPS Subparts A and J for fuel gas combustion devices, except for those heaters and boilers listed in Appendix C, each of which shall be an affected facility and shall be subject to and comply with the requirements of NSPS Subparts A and J for fuel gas combustion devices by the dates listed in Appendix C.

b. By the dates listed in Appendix D, each of the other fuel gas combustion devices that is used to combust refinery fuel gas at any of the Covered Refineries, as listed in Appendix D, shall be an "affected facility," as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall be subject to and comply with the requirements of NSPS Subparts A and J for fuel gas combustion devices.

c. Where Appendix C or D specifies an alternative monitoring plan ("AMP") submittal date (rather than a final NSPS Subpart A and J compliance date), ExxonMobil shall submit to EPA a timely and complete AMP application by the date(s) specified. To the extent that ExxonMobil seeks approval of an alternative monitoring method that is the same or substantially similar to the method identified in the "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas," which is attached hereto in Appendix E, ExxonMobil may begin using such method immediately upon submitting its application for approval to use such method. If an AMP is not approved, ExxonMobil shall submit to EPA for approval a plan for complying with the monitoring requirements of NSPS Subparts A and J for the particular equipment within ninety (90) days of receiving notice of the disapproval. The equipment will become an affected facility when ExxonMobil receives EPA's approval of the relevant AMP. A plan for complying with the monitoring requirements of NSPS Subparts A and J may include a revised AMP application, physical or operational changes to the equipment, or additional or different monitoring.

d. For some heaters and boilers that combust low-flow VOC streams from vents, pumpseals, and other sources, it is anticipated that some of the AMP applications will rely in part on calculating a weighted average H_2S concentration of all VOC and fuel gas streams that are burned in a single heater or boiler and demonstrating with alternative monitoring that either the SO_2 emissions from the heater or boiler will not exceed 20 ppm or that the weighted average H_2S concentration is not likely to exceed 0.1 grains H_2S per dry standard cubic foot of fuel gas. EPA shall not reject an AMP solely due to the AMP's use of one of these approaches to demonstrating compliance with NSPS Subpart J.

60. **<u>Elimination/Reduction of Fuel Oil Burning</u>.** Effective on the Entry Date, ExxonMobil shall not burn Fuel Oil in any combustion unit at any of the Covered Refineries except during periods of Natural Gas Curtailment. Nothing herein is intended to limit, or shall

be interpreted as limiting: (i) the use of torch oil in an FCCU regenerator to assist in starting, restarting, maintaining hot standby, or maintaining regenerator heat balance; or (ii) combustion of acid soluble oil in a combustion device.

61. **Compliance with Consent Decree Constitutes Compliance with Certain NSPS Subpart A Requirements**. For each fuel gas combustion device that becomes an "affected facility," as that term is used in 40 C.F.R. Part 60, Subparts A and J, pursuant to this Subsection V.H, entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for such fuel gas combustion device will 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).

I. SULFUR RECOVERY PLANT OPERATIONS.

62. **General.** ExxonMobil shall comply with the requirements specified below for the Sulfur Recovery Plants ("SRPs") at the Baton Rouge, Baytown, Beaumont, Joliet, and Torrance Refineries.

63. **Sulfur Recovery Plant NSPS Applicability**. Each of the following SRPs shall be an "affected facility," as that term is used in 40 C.F.R. Part 60, Subparts A and J, as follows:

SRP	NSPS Effective Date
Baytown SRP	Consent Decree Entry Date
Beaumont SRP	Consent Decree Entry Date
Joliet SRP	December 31, 2008
Torrance SRP	Consent Decree Entry Date

64. **Sulfur Recovery Plant NSPS Compliance.** By no later than the NSPS Effective Dates specified by Paragraph 63, ExxonMobil shall ensure that the SRPs listed in Paragraph 63 comply with all applicable provisions of NSPS set forth at 40 C.F.R. Part 60, Subparts A and J, including, but not limited to, the following:

a. Emission Limit. ExxonMobil shall, for all periods of operation of these SRPs, comply with 40 C.F.R. § 60.104(a)(2) at each SRP except during periods of startup, shutdown or Malfunction. The startup/shutdown provisions set forth in NSPS Subpart A shall not apply to the independent startup or shutdown of a TGU serving as a control device for the SRP.

b. Monitoring. ExxonMobil shall monitor all emissions points (stacks) to the atmosphere for Tail Gas emissions and shall monitor and report excess emissions from each of these SRPs as required by 40 C.F.R. §§ 60.7(c), 60.13, and 60.105(a)(5), (6) or (7). During the term of this Consent Decree, ExxonMobil shall conduct emissions monitoring from these SRPs with CEMS that are compliant with NSPS requirements at all of the emission points, unless an SO_2 alternative monitoring procedure has been approved by EPA, pursuant to 40 C.F.R. § 60.13(i), for any of the emission points. The requirement for continuous monitoring of the SRP emission points is not applicable to the Acid Gas Flaring Devices used to flare the Acid Gas or Sour Water Stripper Gas diverted from the SRPs.

c. Notice and Initial Performance Test Requirements. For each SRP listed in Paragraph 63, entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for such SRP will 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).

65. **Good Operation and Maintenance and PMO Plans.**

a. By no later than 90 days after the Entry Date, ExxonMobil shall submit to EPA and the Applicable Co-Plaintiffs a summary of the plans, implemented or to be implemented, at each of the Covered Refineries for enhanced maintenance and operation of the SRPs, the control devices, and the appropriate Upstream Process Units. Those plans shall be termed the Preventative Maintenance and Operations Plans ("PMO Plans"). The PMO Plans shall be a compilation of ExxonMobil's approaches for exercising good air pollution control practices and for minimizing SO_2 emissions from sulfur processing and Upstream Process Units at the Covered Refineries. The PMO Plans shall have as its goals the elimination of Acid Gas Flaring and operation of the SRPs between scheduled maintenance turnarounds with minimization of emissions. The PMO Plans shall include, but shall not be limited to, sulfur shedding procedures, startup and shutdown procedures of the SRPs, control devices and Upstream Process Units, emergency procedures and schedules to coordinate maintenance turnarounds of the SRP Claus trains and any control device to coincide with scheduled turnarounds of major Upstream Process Units. Through and after termination of this Consent Decree, ExxonMobil shall implement the PMO Plans at all times, including periods of startup, shutdown and Malfunction, consistent with the requirements imposed by 40 C.F.R. § 60.11(d). Changes to the PMO Plan related to minimizing Acid Gas Flaring and/or SO_2 emissions shall be summarized and reported by ExxonMobil to EPA and the Applicable Co-Plaintiffs in the Semi-Annual Report required under Section IX.

b. EPA and the Applicable Co-Plaintiffs do not, by their review of the PMO Plans and/or by their failure to comment on the PMO Plans, warrant or aver in any manner that any of the actions that ExxonMobil may take pursuant to such PMO Plans will result in compliance with the provisions of the Clean Air Act or any other applicable federal, state, or local law or regulation. Notwithstanding review of the PMO Plans by EPA or the Applicable Co-Plaintiffs, ExxonMobil shall remain solely responsible for compliance with the Clean Air Act and such other laws and regulations.

66. **Baton Rouge and Joliet Optimization Studies and Interim Performance Standards.** ExxonMobil shall complete an optimization study for the Joliet East Claus Train and West Claus Train and an optimization study for the Baton Rouge 100 Claus Train and 200 Claus Train, for the purpose of determining optimal sulfur recovery rates for the aforementioned Claus Trains (the "Optimization Studies"). The Optimization Studies will be used to establish Interim Performance Standards for each of those Claus trains. The Interim Performance Standards for the Baton Rouge 100 Claus Train and 200 Claus Train would apply only during planned routine maintenance on the Baton Rouge TGU, if the relevant Claus train is being operated during the maintenance period, as provided by Paragraph 67. The Interim Performance Standards for the Joliet East Claus Train and West Claus Train would only apply until the Joliet SRP complies with NSPS Subpart J requirements, as provided by Paragraph 68.

a. The Optimization Studies shall be completed by no later than ten (10) months after the Entry Date, and shall include: (i) a detailed evaluation of plant design and capacity, operating parameters and efficiencies - including catalytic activity, and material balances; (ii) an analysis of the composition of the acid gas and sour water stripper gas resulting from the processing of crude slate actually used, or expected to be used; (iii) a thorough review of each critical piece of process equipment and instrumentation within the Claus train that is designed to correct deficiencies or problems that prevent the Claus train from achieving its optimal sulfur recovery efficiency and expanded periods of operation; (iv) establishment of baseline data through testing and measurement of key parameters throughout the Claus train; (v) establishment of a thermodynamic process model of the Claus train; (vi) for any key parameters that have been determined to be at less than optimal levels, initiation of logical, sequential, or stepwise changes designed to move such parameters toward their optimal values;

(vii) verification through testing, analysis of continuous emission monitoring data or other means, of incremental and cumulative improvements in sulfur recovery efficiency, if any; (viii) establishment of new operating procedures for long term efficient operation; and (ix) each study shall be conducted to optimize the performance of the Claus train in light of the actual characteristics of the feeds to the Claus train.

b. Within sixty (60) days after completion of each Optimization Study, ExxonMobil shall submit an Optimization Study Report. Each Optimization Study Report shall: (i) describe the results of the study on the Claus train; (ii) identify recommended physical and operational improvements, if any, that would enhance Claus train efficiency; (iii) propose an Interim Performance Standard (expressed as percent recovery efficiency and/or an emission limitation) for the Claus train; and, if necessary, (iv) propose a schedule for implementing recommended physical or operational improvements required to achieve the proposed Interim Performance Standard.

c. Upon submitting an Optimization Study Report, ExxonMobil shall comply with its proposed Interim Performance Standard in accordance with this Paragraph 66 or, if necessary, shall begin implementing recommended physical or operational improvements required to achieve the proposed Interim Performance Standard.

d. If EPA determines that a more stringent Interim Performance Standard and/or a different implementation schedule is appropriate and can be achieved with a reasonable certainty of compliance, then EPA, after consultation with the Applicable Co-Plaintiff, shall so notify ExxonMobil. Unless ExxonMobil disputes EPA's determination(s) within 90 days of its receipt of that notice, ExxonMobil shall, in accordance with this Paragraph 66, comply with such new standard within 90 days or, if necessary, such other period as may be established by EPA based upon the approved implementation schedule.

67. **Particular Requirements for Baton Rouge.**

a. Good Air Pollution Control Practices. Commencing on the Entry Date, ExxonMobil shall at all times, including periods of startup, shutdown, and malfunction, to the extent practicable, maintain and operate the Baton Rouge Claus trains, the Baton Rouge TGU, and the Baton Rouge Sulfur Recovery incinerator, in a manner consistent with good air pollution control practices for minimizing emissions.

b. Tail Gas Treatment. Commencing on the Entry Date, ExxonMobil shall route all Tail Gas from all Baton Rouge Claus trains to the Baton Rouge TGU, except: (i) during periods of a scheduled Claus train startup, a scheduled Claus train shutdown, or a Claus train or TGU malfunction; or (ii) during planned routine maintenance on the Baton Rouge TGU, as provided by Subparagraph 67.d.

c. Emissions Limits for Normal Operations. Commencing on the Entry Date, emissions from the Baton Rouge Claus trains shall not exceed the following, except during periods of a scheduled Claus train startup, a scheduled Claus train shutdown, or a Malfunction:

(1) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air, on a 12-hour rolling average basis; or

(2) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume hydrogen sulfide (H_2S), calculated as ppm SO_2 by volume (dry basis) at zero percent excess air, on a 12-hour rolling average basis.

d. Particular Requirements Regarding Planned Routine Maintenance on the Baton Rouge TGU. The requirements of this Subparagraph 67.d shall apply to periods of planned routine maintenance on the Baton Rouge TGU after the Entry Date.

(1) ExxonMobil shall minimize emissions associated with planned routine maintenance on the Baton Rouge TGU, to the extent practicable. More specifically, ExxonMobil shall: (i) minimize the duration of each planned routine maintenance period, and specifically limit each such period to no more than 30 calendar days in duration; (ii) maximize TGU run length between planned routine maintenance periods, and specifically limit their frequency to no more than once every five (5) years; (iii) implement appropriate sulfur shedding procedures during any planned routine maintenance period; (iv) cease operation of the 400 Claus Train during planned routine maintenance on the TGU and coordinate planned routine maintenance on the TGU with scheduled turnarounds of the 400 Claus Train and major Upstream Process Units; (v) operate the 100 Claus Train and the 200 Claus Train in compliance with the relevant Baton Rouge Interim Performance Standards, as described above in Paragraph 66, during the planned routine maintenance period; and (vi) seek and obtain LDEQ's advance written approval for the planned routine maintenance period (such as by seeking and obtaining a variance pursuant to La. Admin. Code tit. 33, III § 1505).

(2) The requirements specified by Subparagraph 67.d.(1) shall only apply to planned routine maintenance on the Baton Rouge TGU, and shall not apply to any unplanned shutdown or malfunction.

(3) On a case-by-case basis, EPA will consider any advance written request by ExxonMobil demonstrating that a particular planned routine maintenance

period for the Baton Rouge TGU should be scheduled less than five (5) years after the prior planned maintenance period so that the planned maintenance will coincide with a scheduled turnaround of one or more major Upstream Process Units. If the request is approved in writing by EPA, then ExxonMobil may conduct the planned routine maintenance during the period approved by EPA. During any such planned routine maintenance period approved under this Subparagraph 67.d.(3), ExxonMobil shall comply with all requirements imposed by Subparagraph 67.d.(1) other than the 30 calendar day/5 year restrictions specified by that Subparagraph.

e. Incorporation of Certain Requirements Into Federally-Enforceable Permits. Pursuant to Subsection V.Q of this Consent Decree, ExxonMobil shall apply for a federally-enforceable permit that incorporates the following requirements, to ensure that the requirements shall survive the termination of this Consent Decree: (i) the Interim Performance Standards for the Baton Rouge 100 Claus Train and 200 Claus Train, established pursuant to Subparagraph 66.a; and (ii) the Particular Requirements for Baton Rouge specified by Subparagraphs 67.a - 67.d.

68. **Particular Requirements Applicable to the Joliet SRP.**

a. By no later than December 31, 2008, ExxonMobil shall ensure that the Joliet SRP complies at all times with NSPS Subpart A and J requirements by taking actions that will include either: (i) expanding the Tail Gas handling capacity of the existing TGU, routing all Tail Gas from the East Claus Train and West Claus Train to the expanded TGU, and taking a refinery-wide shutdown during any period of planned routine maintenance on the TGU; or (ii) constructing one or more additional TGU(s) to control the emissions from the East Claus Train and West Claus Train.

b. Until the Joliet SRP complies with NSPS Subpart A and J requirements, ExxonMobil shall operate the East Claus Train and the West Claus Train in compliance with the relevant Joliet Interim Performance Standards, as set out above in Paragraph 66.

69. **Sulfur Pit Emissions.** ExxonMobil shall route all sulfur pit emissions at the Covered Refineries as follows:

a. ExxonMobil shall route or re-route all sulfur pit emissions at the Baytown Refinery and the Beaumont Refinery so that they are eliminated, controlled, or included and monitored as part of the emissions subject to the relevant NSPS Subpart J limit, 40 C.F.R. § 60.104(a)(2), by no later than the Entry Date.

b. ExxonMobil shall route or re-route all sulfur pit emissions at the Joliet Refinery so that they are eliminated, controlled, or included and monitored as part of the emissions subject to the relevant NSPS Subpart J limit, 40 C.F.R. § 60.104(a)(2), by no later than December 31, 2008.

c. ExxonMobil shall route or re-route all sulfur pit emissions at the Torrance Refinery so that they are eliminated, controlled, or included and monitored as part of the emissions subject to the relevant NSPS Subpart J limit, 40 C.F.R. § 60.104(a)(2), by no later than July 1, 2009.

d. ExxonMobil shall, by July 1, 2005, route or re-route all sulfur pit emissions at the Baton Rouge Refinery so that they are eliminated, controlled, or included and monitored as part of the relevant emissions limitations set forth in Paragraph 67.

e. The Parties recognize that periodic maintenance may be required for properly designed and operated sulfur pit emission control systems and/or equipment.

ExxonMobil will take all reasonable measures to minimize emissions while such periodic maintenance is being performed.

J. <u>FLARING DEVICES</u>.

70. **<u>Good Air Pollution Control Practices</u>.** ExxonMobil currently owns and/or operates the Flaring Devices identified in Appendix F to this Consent Decree. On and after the Entry Date, ExxonMobil shall at all times and to the extent practicable, including during periods of startup, shutdown, upset and/or Malfunction, implement good air pollution control practices to minimize emissions from its Flaring Devices, in a manner consistent with the requirements imposed by 40 C.F.R. § 60.11(d).

71. **<u>NSPS Applicability to Flaring Devices</u>**. By no later than the dates identified in Appendix G, ExxonMobil agrees that each NSPS Flaring Device listed in Appendix G of this Consent Decree is an "affected facility" (as that term is used in NSPS, 40 C.F.R. Part 60, Subparts A and J) subject to, and required to comply with, the requirements of 40 C.F.R. Part 60, Subparts A and J, for fuel gas combustion devices. Where two or more dates are set forth in Appendix G with respect to one NSPS Flaring Device, the later of the two dates shall be the date on which the NSPS Flaring Device becomes an "affected facility."

72. **<u>Construction and Operation of Upgraded Flare Gas Recovery Systems</u>.**

a. ExxonMobil currently operates existing flare gas recovery systems at the Baton Rouge, Baytown, Beaumont, Billings, and Torrance Refineries.

b. By no later than 42 months after the Entry Date, ExxonMobil will construct and commence operation of enhancements to its existing flare gas recovery systems at the Beaumont Refinery. Those enhanced flare gas recovery systems will serve certain NSPS Flaring Devices at the Beaumont Refinery, as specified in Appendix G.

c. By no later than 48 months after the Entry Date, ExxonMobil will construct and commence operation of enhancements to its existing flare gas recovery system at the Billings Refinery. That enhanced flare gas recovery system will serve both the NSPS Flaring Devices at the Billings Refinery that are identified in Appendix G.

d. By no later then the Entry Date, ExxonMobil shall construct and commence operation of flare gas recovery facilities at the Joliet Refinery pursuant to the IEPA Construction Permit for the Joliet Coker Blowdown Recovery Project (Application Number 03060091).

73. **<u>Compliance Methods for NSPS Flaring Devices</u>**.

a. ExxonMobil shall comply with the NSPS Subparts A and J requirements for each NSPS Flaring Device by using one or any combination of the following methods

i. Operate and maintain a flare gas recovery system to prevent continuous or routine combustion in the NSPS Flaring Device. Use of a flare gas recovery system on a flare obviates the need to continuously monitor and maintain records of hydrogen sulfide in the gas as otherwise required by 40 C.F.R. §§ 60.105(a)(4) and 60.7;

ii. Eliminate the routes of continuous or intermittent, routinely-generated refinery fuel gases to a NSPS Flaring Device and operate the NSPS Flaring Device such that it receives only process upset gases (as defined in 40 C.F.R. § 60.101(e)), fuel gas released as a result of relief valve leakage or gases released due to other emergency malfunctions;

iii. Operate the NSPS Flaring Device as a fuel gas combustion device and comply with NSPS monitoring requirements by use of a continuous monitor pursuant to 40 C.F.R. § 60.105(a)(4) or with a parametric monitoring system approved by EPA as an alternative monitoring system under 40 C.F.R. § 60.13(i); or

iv. Eliminate all routes of continuous or intermittent, routinely-generated fuel gases to the NSPS Flaring Device – other than the low-volume/low-pressure gas streams specified by Appendix G – and monitor the NSPS Flaring Device by use of a CEMS (in accordance with 40 C.F.R. § 60.105(a)(4)) and a flow meter; <u>provided</u>, <u>however</u>, that this compliance method: (a) may only be used for the three (3) NSPS Flaring Devices at the Baytown Refinery identified in Appendix

G; and (b) may not be used unless each of those NSPS Flaring Devices will emit less than 500 pounds of SO_2 per day under normal conditions.

b. For its existing NSPS Flaring Devices, ExxonMobil shall utilize the compliance method set forth in Appendix G by the dates specified in Appendix G. Where Appendix G specifies an AMP submittal date (rather than a final NSPS Subpart A and J compliance date), ExxonMobil shall submit to EPA a timely and complete AMP application by the date(s) specified. To the extent that ExxonMobil seeks approval of an alternative monitoring method that is the same or substantially similar to the method identified in the "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas," which is attached hereto in Appendix E, ExxonMobil may begin using such method immediately upon submitting its application for approval to use such method. If an AMP is not approved, ExxonMobil shall submit to EPA for approval a plan for complying with the monitoring requirements of NSPS Subparts A and J for the particular equipment within ninety (90) days of receiving notice of the disapproval. The equipment will become an affected facility when ExxonMobil receives EPA's approval of the relevant AMP. A plan for complying with the monitoring requirements of NSPS Subparts A and J may include a revised AMP application, physical or operational changes to the equipment, or additional or different monitoring.

74. **Non-Routinely Generated Gases.** The combustion of gases generated by the startup, shutdown, upset, or Malfunction of a refinery process unit or released to a Flaring Device as a result of relief valve leakage or other emergency Malfunction is exempt from the requirement to comply with 40 C.F.R. § 60.104(a)(1).

75. **<u>Compliance with Consent Decree Constitutes Compliance with Certain NSPS Subpart A Requirements</u>**.

a. <u>Notice Requirements</u>. For each NSPS Flaring Device listed in Appendix G, entry of this Consent Decree will satisfy the notice requirements of 40 C.F.R. § 60.7(a).

b. <u>Performance Test Requirements</u>.

(1) For each NSPS Flaring Device listed in Appendix G that becomes an affected facility under NSPS Subparts A and J pursuant to this Subsection V.J, entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for the NSPS Flaring Device shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirements of 40 C.F.R. § 60.8(a).

(2) Within 180 days of the Entry Date, for the NSPS Flaring Devices identified in Appendix G: (i) ExxonMobil shall conduct a velocity test on the NSPS Flaring Device pursuant to 40 C.F.R. § 60.18; <u>or</u> (ii) in lieu of conducting the velocity test required by 40 C.F.R. § 60.18, ExxonMobil may submit velocity calculations which demonstrate that the NSPS Flaring Device meets the performance specification required by 40 C.F.R. § 60.18.

76. **<u>Periodic Maintenance of Flare Gas Recovery Systems</u>.** The Parties recognize that periodic maintenance may be required for properly designed and operated flare gas recovery systems. ExxonMobil will take all reasonable measures to minimize emissions while such periodic maintenance is being performed.

77. **<u>Safe Operation of Refining Processes</u>.** The Parties recognize that under certain conditions, a flare gas recovery system may need to be bypassed in the event of an emergency or

in order to ensure safe operation of refinery processes. Nothing in this Consent Decree precludes ExxonMobil from temporarily bypassing a flare gas recovery system under such circumstances.

K. <u>CONTROL OF ACID GAS FLARING AND TAIL GAS INCIDENTS</u>.

78. **<u>AG Flaring History and Corrective Measures</u>**. ExxonMobil has conducted a review of past AG Flaring Incidents that occurred at the Covered Refineries between January 1, 1998 and December 1, 2004, and has provided EPA a summary identifying the AG Flaring Incidents that occurred during that period, their probable causes, and the estimated emissions. ExxonMobil has implemented (or is in the process of implementing) corrective measures to address the root causes of the prior incidents and to minimize the number and duration of Acid Gas Flaring Incidents.

79. **<u>Future AG Flaring Incidents and Tail Gas Incidents</u>**. As specified by this Subsection V.K, and consistent with the requirements of 40 C.F.R. § 60.11(d), ExxonMobil shall investigate the cause of future AG Flaring Incidents and Tail Gas Incidents, take reasonable steps to correct the conditions that have caused or contributed to such AG Flaring Incidents and Tail Gas Incidents, and minimize AG Flaring Incidents and Tail Gas Incidents at the Covered Refineries. ExxonMobil shall continue to follow the AG Flaring Incident investigation and corrective action procedures outlined in this Subsection V.K after termination of the Consent Decree, but the reporting and stipulated penalty provisions of this Subsection shall not apply after termination.

80. **<u>Investigation and Reporting</u>.** No later than forty-five (45) days following the end of an AG Flaring Incident occurring after the Entry Date, ExxonMobil shall submit to EPA and the Applicable Co-Plaintiff a report that sets forth the following:

i. The date and time that the AG Flaring Incident started and ended. To the extent that the AG Flaring Incident involved multiple releases either within a twenty-four (24) hour period or within subsequent, contiguous, non-overlapping twenty-four (24) hour periods, ExxonMobil shall set forth the starting and ending dates and times of each release;

ii. An estimate of the quantity of sulfur dioxide that was emitted and the calculations that were used to determine that quantity;

iii. The steps, if any, that ExxonMobil took to limit the duration and/or quantity of sulfur dioxide emissions associated with the AG Flaring Incident;

iv. A detailed analysis that sets forth the Root Cause and all significant contributing causes of that AG Flaring Incident, to the extent determinable;

v. An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an AG Flaring Incident resulting from the same Root Cause or significant contributing causes in the future. If two or more reasonable alternatives exist to address the Root Cause, the analysis shall discuss the alternatives, if any, that are available, the probable effectiveness and cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation and maintenance changes shall be evaluated. If ExxonMobil concludes that corrective action(s) is (are) required under Paragraph 81, the report shall 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 ExxonMobil concludes that corrective action is not required under Paragraph 81, the report shall explain the basis for that conclusion;

vi. A statement that: (a) specifically identifies each of the grounds for stipulated penalties in Paragraphs 83 and 84 of this Decree and describes whether or not the AG Flaring Incident falls under any of those grounds, provided, however, that ExxonMobil may choose to submit with the Root Cause Failure Analysis a payment of stipulated penalties in the nature of settlement without the need to specifically identify the grounds for the penalty. 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 ExxonMobil's potential defenses; (b) if an AG Flaring Incident falls under Paragraph 85 of this Decree, describes which Subparagraph (i.e., 85.a or 85.b) applies and why; and (c) if an AG Flaring Incident falls under either Paragraph 84 or Subparagraph 85.b, states whether or not ExxonMobil asserts a defense to the AG Flaring Incident, and if so, a description of the defense;

vii. To the extent that investigations of the causes and/or possible corrective actions still are underway on the due date of the report, a statement of the anticipated date by which a follow-up report fully conforming to the requirements of Subparagraphs 80.iv and 80.v shall be submitted; provided, however, that if ExxonMobil has not submitted a report or a series of reports containing the information required to be submitted under this Paragraph within the 45 day time period set forth in this Paragraph 80 (or such additional time as EPA may allow) after the due date for the initial report for the AG Flaring Incident, the stipulated penalty provisions of Section XI shall apply, but ExxonMobil shall retain the right to dispute, under the dispute resolution provision of this Consent Decree, any demand for stipulated penalties that was issued as a result of ExxonMobil's failure to submit the report required under this Paragraph within the time frame set forth. Nothing in this Paragraph shall be deemed to excuse ExxonMobil from its investigation, reporting, and corrective action obligations under this Section for any AG Flaring Incident which occurs after an AG Flaring Incident for which ExxonMobil has requested an extension of time under this Subparagraph 80.vii; and

viii. To the extent that completion of the implementation of corrective action(s), if any, is not finalized at the time of the submission of the report required under this Paragraph, then, by no later than thirty (30) days after completion of the implementation of corrective action(s), ExxonMobil shall submit a report identifying the corrective action(s) taken and the dates of commencement and completion of implementation.

81. **Corrective Action.**

a. In response to any AG Flaring Incident occurring after the Entry Date, ExxonMobil 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 and all significant contributing causes of that AG Flaring Incident.

b. If EPA does not notify ExxonMobil in writing within forty-five (45) days of receipt of the report(s) required by Paragraph 80 that it objects to one or more aspects of the proposed corrective action(s) and schedule(s) of implementation, if any, then that (those) action(s) and schedule(s) shall be deemed acceptable for purposes of compliance with Subparagraph 81.a of this Decree. EPA does not, however, by its failure to object to any corrective action that ExxonMobil may take in the future, warrant or aver in any manner that any corrective actions in the future shall result in compliance with the provisions of the Clean Air Act or its implementing regulations.

c. If EPA objects, in whole or in part, to the proposed corrective action(s) and/or the schedule(s) of implementation or, where applicable, to the absence of such proposal(s) and/or schedule(s), it shall notify ExxonMobil and explain the basis for its objection (s) in writing within forty-five (45) days following receipt of the report(s) required by Paragraph 80, and ExxonMobil shall respond promptly to EPA's objection(s).

d. Nothing in this Subsection V.K shall be construed to limit the right of ExxonMobil to take such corrective actions as it deems necessary and appropriate immediately following an AG Flaring Incident or in the period during preparation and review of any reports required under this Paragraph.

82. **<u>Stipulated Penalties for AG Flaring Incidents</u>.** The provisions of Paragraphs 83-85 are to be used by EPA in assessing stipulated penalties for AG Flaring Incidents occurring after the Entry Date and by the United States in demanding stipulated penalties under this Section V.K. The provisions of Paragraphs 83-85 do not apply to HC Flaring Incidents.

83. The stipulated penalty provisions of Paragraph 192 shall apply to any AG Flaring Incident for which the Root Cause was one or more of the following acts, omissions, or events:

i. Error resulting from careless operation by the personnel charged with the responsibility for the Sulfur Recovery Plant, TGU, or Upstream Process Units;

ii. Failure to follow written procedures;

iii. A failure of equipment that is due to a failure by ExxonMobil to operate and maintain that equipment in a manner consistent with good engineering practice;

iv. North Claus Train furnace power supply interlock system failures at the Joliet Refinery; or

v. Problems with SRP Unit 29B steam drum level controllers at the Torrance Refinery.

84. If the AG Flaring Incident is not a result of one of the Root Causes identified in Paragraph 83, then the stipulated penalty provisions of Paragraph 192 shall apply if the AG Flaring Incident:

i. Results in emissions of sulfur dioxide at a rate greater than twenty (20.0) pounds per hour continuously for three (3) consecutive hours or more and ExxonMobil failed to act in accordance with its PMO Plan and/or to take any action during the AG Flaring Incident to limit the duration and/or quantity of SO_2 emissions associated with such incident; or

ii. Causes the total number of AG Flaring Incidents in a rolling twelve (12) month period to exceed five (5) for a particular Covered Refinery.

85. With respect to any AG Flaring Incident not identified in Paragraphs 83 or 84, the following provisions shall apply:

a. First Time: If the Root Cause of the AG Flaring Incident was not a recurrence of the same Root Cause that resulted in a previous AG Flaring Incident that occurred since the Entry Date, then:

(1) If the Root Cause of the AG Flaring 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 AG Flaring Incidents;

(2) If the Root Cause of the AG Flaring Incident was sudden and infrequent, and was reasonably preventable through the exercise of good engineering practice, then ExxonMobil shall implement corrective action(s) pursuant to Paragraph 81, and the stipulated penalty provisions of Paragraph 192 shall not apply.

b. Recurrence: If the Root Cause is a recurrence of the same Root Cause that resulted in a previous AG Flaring Incident that occurred since the Entry Date, then ExxonMobil shall be liable for stipulated penalties under Paragraph 192 unless:

(1) the AG Flaring Incident resulted from a Malfunction; or

(2) the Root Cause previously was designated as an agreed-upon Malfunction under Subparagraph 85.a.(1); or

(3) the AG Flaring Incident had as its Root Cause the recurrence of a Root Cause for which ExxonMobil had previously developed, or was in the process of developing, a corrective action plan for which ExxonMobil had not yet completed implementation.

86. **Defenses.** ExxonMobil may raise the following affirmative defenses in response to a demand by the United States for stipulated penalties:

i. Force majeure.

ii. As to Paragraph 83, the AG Flaring Incident does not meet the identified criteria.

iii. As to Paragraph 84, Malfunction.

iv. As to Paragraph 85, the AG Flaring Incident does not meet the identified criteria and/or was due to a Malfunction.

87. In the event a dispute under Paragraphs 82-86 is brought to the Court pursuant to the Dispute Resolution provisions of this Consent Decree, ExxonMobil may also assert a startup, shutdown and/or Malfunction defense, but the United States shall be entitled to assert that such defenses are not available. If ExxonMobil prevails in persuading the Court that the defenses of startup, shutdown and/or Malfunction are available for AG Flaring Incidents under 40 C.F.R. 60.104(a)(1), ExxonMobil shall not be liable for stipulated penalties for emissions resulting from

such startup, shutdown and/or Malfunction. If the United States prevails in persuading the Court that the defenses of startup, shutdown and/or Malfunction are not available, ExxonMobil shall be liable for such stipulated penalties.

88. Other than for a Malfunction or force majeure, if no AG Flaring Incident occurs at a Covered Refinery for a rolling 36 month period, then the stipulated penalty provisions of Subsection V.K. shall no longer apply to that Covered Refinery. EPA may elect to reinstate the stipulated penalty provision if ExxonMobil has an AG 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 continue for the remaining term of this Consent Decree.

89. **Billings AG Flaring Incidents**. With respect to AG Flaring Incidents occurring within the Billings Refinery, ExxonMobil shall not be entitled to assert failures, at Montana Sulfur and Chemicals Company’s contiguous facility, of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner as a Malfunction defense. Nothing in this Consent Decree shall be construed as to impose any liability on the part of ExxonMobil for Acid Gas Flaring occurring within Montana Sulfur and Chemical Company's contiguous facility.

90. **Emission Calculations**.

a. Calculation of the Quantity of Sulfur Dioxide Emissions Resulting from AG Flaring. For purposes of this Consent Decree, the quantity of SO_2 emissions resulting from an AG Flaring Incident shall be calculated by the following formula:

Tons of SO_2 = [FR][TD][ConcH_2S][8.44×10^{-5}].

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.) For purposes of determining the occurrence of, or the total quantity of SO_2 emissions resulting from, an AG Flaring Incident that is comprised of intermittent AG Flaring, the quantity of SO_2 emitted shall be equal to the sum of the quantities of SO_2 flared during each 24-hour period starting when the Acid Gas was first flared.

b. Calculation of the Rate of SO_2 Emissions During AG Flaring. For purposes of this Consent Decree, the rate of SO_2 emissions resulting from an AG Flaring Incident shall be expressed in terms of pounds per hour and shall be calculated by the following formula:

$$ER = [FR][ConcH_2S][0.169].$$

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 SO_2 per hour, the emission rate shall be rounded to 20.0 pounds of SO_2 per hour; for a calculation that results in an emission rate of 20.05 pounds of SO_2 per hour, the emission rate shall be rounded to 20.1.)

c. Meaning of Variables and Derivation of Multipliers Used in the Equations in this Paragraph 90:

ER =	Emission Rate in pounds of SO_2 per hour
FR =	Average Flow Rate to Flaring Device(s) during Flaring Incident in standard cubic feet per hour
TD =	Total Duration of Flaring Incident in hours
$ConcH_2S$ =	Average Concentration of Hydrogen Sulfide in gas during Flaring Incident (or immediately prior to Flaring Incident if all gas is being flared) expressed as a volume fraction (scf H_2S/scf gas)

8.44×10^{-5} =	[lb mole H_2S/379 scf H_2S][64 lbs SO_2/lb mole H_2S][Ton/2000 lbs]
0.169 =	[lb mole H_2S/379 scf H_2S][1.0 lb mole SO_2/1 lb mole H_2S][64 lb SO_2/1.0 lb mole SO_2]

The flow of gas to the AG Flaring Device(s) ("FR") shall be as measured by the relevant flow meter or reliable flow estimation parameters. Hydrogen sulfide concentration ("ConcH_2S") shall be determined from the Sulfur Recovery Plant feed gas analyzer, from knowledge of the sulfur content of the process gas being flared, by direct measurement by Tutwiler or Draeger (or other colorimetric) tube analysis or by any other method approved by EPA or an Applicable Co-Plaintiff. 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 under Paragraph 80 shall include the data used in the calculation and an explanation of the basis for any estimates of missing data points.

91. **Tail Gas Incidents**.

a. Investigation, Reporting, Corrective Action and Stipulated Penalties. For Tail Gas Incidents, ExxonMobil shall follow the same investigative, reporting, corrective action and assessment of stipulated penalty procedures and schedules as those set forth in Paragraphs 80-88 for AG Flaring Incidents. Those procedures shall be applied to TGU shutdowns, bypasses of a TGU, or other events which result in a Tail Gas Incident, including unscheduled shutdowns of an SRP. Commencing on the Entry Date, this Paragraph 91 shall apply to Tail Gas Incidents involving combustion of Tail Gas from: (i) the Baytown SRP; (ii) the Beaumont SRP; (iii) the Torrance SRP; (iv) the Joliet North Claus Train; and (v) the Baton Rouge Claus trains, except during periods of planned routine maintenance on the Baton Rouge TGU performed in compliance with Subparagraph 67.d. After December 31, 2008, this Paragraph 91 shall also apply to Tail Gas Incidents involving combustion of Tail Gas from the Joliet SRP's East Claus Train and West Claus Train. ExxonMobil shall continue to follow the Tail Gas Incident investigation and corrective action procedures after termination of the Consent Decree, but the reporting and stipulated penalty provisions of this Subsection shall not apply after termination.

b. Calculation of the Quantity of SO_2 Emissions Resulting from a Tail Gas Incident. For the purposes of this Consent Decree, the quantity of SO_2 emissions resulting from a Tail Gas Incident shall be calculated by one of the following methods, based on the type of event:

i. If Tail Gas is combusted in a flare, the SO_2 emissions are calculated using the methods outlined in Paragraph 90; or

ii. If Tail Gas exceeding the 250 ppmvd NSPS J limit is emitted from a monitored SRP incinerator, then the following formula applies:

$$ER_{TGI} = \sum_{i=1}^{TD_{TGI}} [\ FR_{Inc.}]_i\ [\text{Conc. } SO_2 - 250]_i\ [0.169 \times 10^{-6}]\ [[20.9 - \%\ O_2]/[20.9]]_i$$

Where:

ER_{TGI} = Emissions from Tail Gas Unit at the SRP incinerator, pounds of SO_2 over a 24 hour period

TD_{TGI} = Hours when the incinerator CEM was exceeding 250 ppmvd SO_2 on a rolling twelve hour average, corrected to 0% O2, in each 24 hour period of the Incident

i = Each hour within TD_{TGI}

$FR_{Inc.}$ = 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 = The 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

0.169×10^{-6} = [lb mole of SO_2 / 379 scf SO_2] [64 lbs SO_2 / lb mole SO_2] [1×10^{-6}]

Standard conditions = 60 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 ExxonMobil shall estimate emissions based on best engineering judgment.

L. **<u>CONTROL OF HYDROCARBON FLARING INCIDENTS</u>**.

92. **<u>HC Flaring Incidents</u>**. For HC Flaring Incidents occurring after the Entry Date, ExxonMobil shall follow the same investigative, reporting, and corrective action procedures as those set forth in Subsection V.K for AG Flaring Incidents. However:

i. ExxonMobil shall submit the HC Flaring Incident(s) reports as part of the Semi-Annual Reports required pursuant to Section IX, rather than on an incident-by-incident basis.

ii. For each of the Flaring Devices identified in Appendix F, ExxonMobil may prepare and submit a single Root Cause Analysis for one or more Root Causes found by that analysis to routinely recur. ExxonMobil will inform EPA and the Applicable Co-Plaintiff that it is electing to report only once on that Root Cause(s). Unless EPA or the Applicable Co-Plaintiff objects within thirty (30) days of receipt of the Root Cause Analysis, such election will be effective.

iii. For the six (6) month period after the installation of a flare gas recovery system (that is, during the time in which the flare gas recovery system is being commissioned), ExxonMobil will not be required to undertake HC Flaring Incident investigations if the Root Cause of the HC Flaring Incident is directly related to the commissioning of the flare gas recovery system.

iv. In lieu of analyzing possible corrective actions under Subparagraph 80.v and taking interim and/or long-term corrective action under Paragraph 81 for a HC Flaring Incident attributable to the startup or shutdown of a process unit that ExxonMobil has previously analyzed under this Paragraph, ExxonMobil may identify such prior analysis when submitting the report required under this Paragraph.

v. To the extent that a HC Flaring Incident at a Covered Refinery has as its Root Cause the bypass of a flare gas recovery system for safety or maintenance reasons as set forth in Paragraphs 76 - 77, ExxonMobil will be required to describe only the HC Flaring Incident and to list the date, time, and duration of such Incident in the Semi-Annual Reports due under Section IX.

ExxonMobil shall continue to follow the HC Flaring Incident investigation and corrective action procedures after termination of the Consent Decree, but the reporting provisions of this Subsection shall not apply after termination.

93. Stipulated penalties under Paragraphs 82-85 and Paragraph 192 shall not apply to HC Flaring Incident(s).

94. The formulas at Paragraph 90, used for calculating the quantity and rate of SO_2 emissions during AG Flaring Incidents, shall be used to calculate the quantity and rate of SO_2 emissions during HC Flaring Incidents.

M. CERCLA/EPCRA REPORTING.

95. **CERCLA/EPCRA Compliance Review for Acid Gas Flaring Incidents**. ExxonMobil shall conduct a review of past AG Flaring Incidents that occurred at the Baton Rouge, Baytown, Beaumont, Billings, and Joliet Refineries between January 1, 1998 and the Date of Lodging to determine its compliance with applicable requirements of Section 103(a) of CERCLA, 42 U.S.C. § 9603(a), and Section 304 of EPCRA, 42 U.S.C. § 11004, with respect to reporting SO_2 and H_2S releases resulting from those AG Flaring Incidents. Upon completion of this review, ExxonMobil shall complete the following activities by no later than ninety (90) days after the Entry Date:

a. correct any identified violations by submitting reports to the appropriate agencies consistent with the requirements of Section 103(a) of CERCLA and Section 304 of EPCRA; and

b. submit a CERCLA/EPCRA Compliance Review Report to EPA and the Applicable Co-Plaintiff that: (i) identifies all AG Flaring Incidents; (ii) if associated violations of Section 103(a) of CERCLA and Section 304 of EPCRA related to SO_2 and H_2S were identified with respect to any such AG Flaring Incidents, contains a list of such violations for which ExxonMobil seeks a resolution of liability; and (iii) attaches to such report copies of any corrective reports filed by ExxonMobil pursuant to Subparagraph 95.a., above.

96. **<u>CERCLA/EPCRA Reporting for the Joliet Refinery</u>**. For any release at the Joliet Refinery after the Entry Date that is reportable under CERCLA Section 103(a) and/or EPCRA Section 304:

i. ExxonMobil shall report any such release that is reportable under CERCLA Section 103(a) to the National Response Center , the State Emergency Response Center, and the Local Emergency Planning Committee as soon as ExxonMobil has knowledge that a Reportable Quantity has been released;

ii. ExxonMobil shall report any such release that is reportable under EPCRA Section 304 to the State Emergency Response Center and the Local Emergency Planning Committee immediately after ExxonMobil knows that a Reportable Quantity has been released, and shall submit required followup reports within 7 days of that time; and

iii. ExxonMobil shall be liable for payment of stipulated penalties under Paragraph 198 for failure to report a release as required by the preceding Subparagraphs 96.i and/or 96.ii.

N. <u>BENZENE WASTE NESHAP PROGRAM ENHANCEMENTS.</u>

97. In addition to continuing to comply with all applicable requirements of 40 C.F.R. Part 61, Subpart FF ("Benzene Waste NESHAP," "BWON," or "Subpart FF"), ExxonMobil agrees to undertake the measures set forth in this Subsection V.N to ensure continuing compliance with Subpart FF and to minimize or eliminate fugitive benzene waste emissions at the Covered Refineries.

98. **<u>Subpart FF Compliance Status.</u>**

a. Commencing on the Date of Entry, ExxonMobil's Baton Rouge Refinery and Beaumont Refinery shall comply with the compliance option set forth at 40 C.F.R.

§ 61.342(c), utilizing the exemptions set forth in 40 C.F.R. § 61.342(c)(2) and (c)(3)(ii) (hereinafter referred to as the "2 Mg Compliance Option").

b. Commencing on the Date of Entry, ExxonMobil's Baytown Refinery, Billings Refinery, Joliet Refinery, and Torrance Refinery shall comply with the compliance option set forth at 40 C.F.R. § 61.342(e) (hereinafter referred to as the "6 BQ Compliance Option").

99. **Refinery Compliance Status Changes.** During the term of this Consent Decree, ExxonMobil shall not change the compliance status of any Covered Refinery from the 6 BQ Compliance Option to the 2 Mg Compliance Option.

100. **One-Time Review and Verification of Each Covered Refinery's TAB and Compliance Status**.

a. Phase One of the Review and Verification Process. By no later than 180 days after the Entry Date, ExxonMobil shall complete a review and verification of each Covered Refinery's Total Annual Benzene ("TAB") and its compliance with the applicable compliance option. ExxonMobil's review and verification process shall include, but not be limited to:

i. an identification of each waste stream that is required to be included in the Refinery's TAB (e.g., slop oil, tank water draws, spent caustic, desalter rag layer dumps, desalter vessel process sampling points, other sample wastes, maintenance wastes, and turnaround wastes);

ii. a review and identification of the calculations and/or measurements used to determine the flows of each waste stream for the purpose of ensuring the accuracy of the annual waste quantity for each waste stream;

iii. an identification of the benzene concentration in each waste stream, including sampling for benzene concentration at no less than 10 waste streams per Covered Refinery, consistent with the requirements of 40 C.F.R. § 61.355(c)(1) and (3); provided, however, that previous analytical data or documented knowledge of waste streams may be used, 40 C.F.R. § 61.355(c)(2), for streams not sampled.

Streams sampled after January 1, 2004 may be applied toward the waste streams requiring sampling;

iv. an identification of whether or not the stream is controlled consistent with the requirements of Subpart FF; and

v. an identification of any existing noncompliance with the requirements of Subpart FF.

By no later than 30 days following the completion of Phase One of the review and verification process, ExxonMobil shall submit to EPA and the Applicable Co-Plaintiff a BWON Compliance Review and Verification Report for each Covered Refinery that sets forth the results of Phase One, including but not limited to the items identified in Subparagraphs a.i through a.v of this Paragraph.

b. Phase Two of the Review and Verification Process. Based on EPA's review of the BWON Compliance Review and Verification Reports, EPA may select up to 20 additional waste streams at each Covered Refinery for additional sampling or re-sampling for benzene concentration. ExxonMobil shall conduct the required sampling under representative conditions and submit the results to EPA within 60 days of receipt of EPA's request. ExxonMobil shall use the results of this additional sampling to reevaluate the TAB and the uncontrolled benzene quantity and to amend the BWON Compliance Review and Verification Report, as needed. To the extent that EPA requires ExxonMobil to re-sample a waste stream as part of the Phase Two review that ExxonMobil chose to sample as part of the Phase One review, ExxonMobil may average the results of the two sampling events. ExxonMobil shall submit an amended BWON Compliance Review and Verification Report within 90 days following the date of the completion of the required Phase Two sampling, if Phase Two sampling is required by EPA.

101. **<u>Implementation of Actions Necessary to Correct Non-Compliance or to Come Into Compliance</u>.**

a. <u>Amended TAB Reports</u>. If the results of the BWON Compliance Review and Verification Report indicate that the reports required by 40 C.F.R. § 61.357(c) or 61.357(d) have not been filed or are inaccurate and/or do not satisfy the requirements of Subpart FF, ExxonMobil shall submit, by no later than sixty (60) days after completion of the BWON Compliance Review and Verification Report(s), an amended TAB report to EPA and the Applicable Co-Plaintiff.

b. <u>BWON Corrective Measures Plan</u>.

(1) <u>Baton Rouge and Beaumont Refineries</u>. If the results of the BWON Compliance Review and Verification Report indicate that ExxonMobil is not in compliance with the 2 Mg Compliance Option at the Baton Rouge Refinery or the Beaumont Refinery, ExxonMobil shall submit to EPA and the Applicable Co-Plaintiff, by no later than ninety (90) days after completion of the BWON Compliance Review and Verification Report, a BWON Corrective Measures Plan that identifies with specificity the compliance strategy and schedule that ExxonMobil shall implement to ensure that the Refinery complies with the 2 Mg Compliance Option as soon as practicable.

(2) <u>Baytown, Billings, Joliet, and Torrance Refineries</u>. If the results of the BWON Compliance Review and Verification Report indicate that ExxonMobil is not in compliance with the 6 BQ Compliance Option at the Baytown Refinery, the Billings Refinery, the Joliet Refinery, or the Torrance Refinery, ExxonMobil shall submit to the EPA and the Applicable Co-Plaintiff, by no later than ninety (90) days after completion of the BWON Compliance Review and Verification Report, a BWON Corrective

Measures Plan that identifies with specificity the compliance strategy and schedule that ExxonMobil shall implement to ensure that the Refinery complies with the 6 BQ Compliance Option as soon as practicable.

c. Review and Approval of Plans Submitted Pursuant to Subparagraph 101.b. Any plan submitted pursuant to Subparagraph 101.b shall be subject to approval or disapproval by EPA, which shall act after an opportunity for consultation with the Applicable Co-Plaintiff. Within sixty (60) days after receiving any notification of disapproval from EPA, ExxonMobil shall submit to the EPA and the Applicable Co-Plaintiff a revised plan that responds to all identified or alleged deficiencies. Upon receipt of approval or approval with conditions, ExxonMobil shall implement the plan according to the schedule provided in the approved plan.

d. Certification of Compliance with the 2 Mg Compliance Option or the 6 BQ Compliance Option, as Applicable. By no later than 30 days after completion of the implementation of all actions, if any, required pursuant to Subparagraphs 101.b or 101.c to come into compliance with the 2 Mg Compliance Option or the 6 BQ Compliance Option, as applicable, ExxonMobil shall submit a report to EPA and the Applicable Co-Plaintiff certifying that, as to the subject Refinery, the Refinery complies with the Benzene Waste NESHAP.

102. **Carbon Canisters**. ExxonMobil shall comply with the requirements of this Paragraph 102 at all locations at the Covered Refineries where a carbon canister(s) is utilized as a control device under the Benzene Waste NESHAP.

a. By no later than 180 days after the Entry Date, ExxonMobil shall complete installation of primary and secondary carbon canisters at locations currently utilizing single canisters and shall operate them in series. By no later than 30 days following completion of the installation of the dual canisters, ExxonMobil shall submit a report certifying the completion of the installation. The report shall include: (i) a list of all locations at each Covered Refinery where carbon canister systems are used as a control device under Subpart FF; (ii) an indication, for each location, whether there was a pre-existing secondary carbon canister or whether a secondary carbon canister was installed under this Paragraph; (iii) the installation date of each such secondary canister installed under this Paragraph and the date that each secondary canister was put into operation; and (iv) an indication, for each location, whether volatile organic compounds ("VOC") or benzene will be used to monitor for breakthrough under and as required by Subparagraph 102.d.

b. Except as expressly permitted under Paragraph 102.g, ExxonMobil shall not use single carbon canisters for any new units or installations at the Covered Refineries that require controls pursuant to the Benzene Waste NESHAP.

c. For dual carbon canister systems, "breakthrough" between the primary and secondary canister is defined as any reading equal to or greater than 50 ppm VOC or 5 ppm benzene (depending upon the constituent that ExxonMobil decides to monitor).

d. ExxonMobil shall monitor for breakthrough between the primary and secondary carbon canisters monthly, or in accordance with the frequency specified in 40 C.F.R. § 61.354(d), whichever is more frequent. This requirement shall commence: (i) upon the Entry Date where dual carbon canisters currently are in service; and (ii) within seven days after installation of a new dual carbon canister system.

e. If ExxonMobil monitors a canister system for benzene and detects between 1 ppm and 5 ppm benzene between the primary and secondary canisters, then ExxonMobil shall begin monitoring for breakthrough (at 5 ppm benzene) between the primary and secondary carbon canisters weekly, or in accordance with the frequency specified in 40 C.F.R. § 61.354(d), whichever is more frequent.

f. ExxonMobil shall replace the original primary carbon canister (or route the flow to an appropriate alternative control device) immediately when breakthrough is detected between the primary and secondary canister. The original secondary carbon canister (or a fresh canister) will become the new primary carbon canister and a fresh carbon canister will become the secondary canister. For purposes of this Subparagraph, "immediately" shall mean within eight (8) hours of the detection of a breakthrough for canisters of 55 gallons or less, and within twenty-four (24) hours of the detection of a breakthrough for canisters greater than 55 gallons. In lieu of replacing the primary canister immediately, ExxonMobil may elect to monitor the outlet of the secondary canister beginning on the day the breakthrough between the primary and secondary canister is identified and each calendar day thereafter. This daily monitoring shall continue until the primary canister is replaced. If the constituent being monitored (either benzene or VOC) is detected at the outlet of the secondary canister during this period of daily monitoring, both canisters must be replaced within eight (8) hours of the detection of a breakthrough.

g. Temporary Applications. ExxonMobil may utilize properly-sized single canisters for short-term operations such as with temporary storage tanks or as temporary control devices. For canisters operated as part of a single canister system, "breakthrough" is defined for purposes of this Consent Decree as any reading of VOC above background or benzene above 1 ppm (whichever is monitored). Beginning no later than the Entry Date, ExxonMobil shall monitor for breakthrough from a single carbon canister system once every calendar day that there is actual flow to the carbon canister. ExxonMobil shall replace the single carbon canister with a fresh carbon canister, discontinue flow, or route the stream to an alternate, appropriate device immediately when breakthrough is detected. For purpose of this Subparagraph, "immediately" shall mean within eight (8) hours for canisters of 55 gallons or less and twenty-four (24) hours for canisters greater than 55 gallons. If a single canister has been found to exceed the applicable breakthrough concentration, flow must be discontinued to that canister immediately. Such a spent canister may not be placed back into Benzene Waste NESHAP vapor control service until it has been appropriately regenerated.

h. ExxonMobil shall maintain a readily-available supply of fresh carbon canisters at all times at each Covered Refinery where canisters are used as a control device or shall otherwise ensure that such canisters are readily available to implement the requirements of this Paragraph 102.

i. ExxonMobil shall maintain records associated with the requirements of this Paragraph, including carbon canister monitoring readings and the constituents being monitored for at least five (5) years after such readings occur.

103. **Annual Review.** By no later than 120 days after the Entry Date, ExxonMobil shall modify, as necessary, its existing written management of change procedures to provide for an annual review of process information for each Covered Refinery, including but not limited to construction projects, to ensure that all new benzene waste streams are included in the Refinery's waste stream inventory. ExxonMobil shall conduct such reviews on an annual basis.

104. **Laboratory Audits**. ExxonMobil shall conduct audits of all laboratories that perform analyses of ExxonMobil's Benzene Waste NESHAP samples to ensure that proper analytical and quality assurance/quality control procedures are followed for such samples.

a. By no later than 180 days after the Entry Date, ExxonMobil shall complete initial audits of at least half of the laboratories used by the Covered Refineries within 180 days after the Entry Date, and shall complete initial audits of the remaining laboratories within 365 days of the Entry Date. In addition, ExxonMobil shall audit any new laboratory to be used for analyses of benzene samples from the Covered Refineries prior use of the new laboratory. If ExxonMobil has completed an audit of any laboratory on or after January 1, 2004, initial audits of those laboratories pursuant to this Subparagraph shall not be required.

b. During the term of this Consent Decree, ExxonMobil shall conduct subsequent laboratory audits, such that each laboratory is audited once every two (2) calendar years.

c. ExxonMobil may conduct audits itself, retain third parties to conduct these audits, or use audits conducted by others as its own, but the responsibility and obligation to ensure compliance with this Consent Decree and Subpart FF are solely ExxonMobil's.

105. **Benzene Spills**. For each spill at each Covered Refinery after the Entry Date, ExxonMobil shall review the spill to determine if any benzene waste, as defined by Subpart FF, was generated. For each spill involving the release of more than 10 pounds of benzene in a 24 hour period, ExxonMobil shall: (i) include the benzene waste generated by the spill in the Covered Refinery's TAB, as required by 40 C.F.R. § 61.342; and (ii) as appropriate, account for such benzene waste in accordance with the applicable compliance option.

106. **Training.**

a. By no later than 90 days after the Entry Date, ExxonMobil shall develop and implement a program for annual (i.e., once each calendar year) training for all employees who draw benzene waste samples for Benzene Waste NESHAP purposes.

b. By no later than 120 days after the Entry Date, ExxonMobil shall complete the development of standard operating procedures (where they do not already exist) for all control devices and treatment processes used to comply with the Benzene Waste NESHAP at each Covered Refinery. By no later than 180 days after the Entry Date, ExxonMobil shall complete an initial training program regarding these procedures for all operators assigned to the relevant equipment. Comparable training shall also be provided to any persons who subsequently become operators, prior to their assumption of this duty. "Refresher" training in these procedures shall be performed on a three-year cycle (i.e., once every three calendar years).

c. ExxonMobil shall assure that the employees of any contractors hired to perform any of the requirements of this Subsection V.N are properly trained to implement such requirements that they are hired to perform, as under Subparagraphs 106.a-106.c.

107. **Waste/Slop/Off-Spec Oil Management**.

a. Schematics. By no later than 120 days after the Entry Date, ExxonMobil shall submit to the EPA and the Applicable Co-Plaintiff schematics for each Covered Refinery that: (i) depict the waste management units (including sewers) that handle, store, and transfer waste/slop/off-spec oil streams; (ii) identify the control status of each waste management unit; and (iii) show how such oil is transferred within the Refinery. Representatives from ExxonMobil and EPA thereafter may confer about the appropriate characterization of each waste/slop/off-spec oil streams and the necessary controls, if any, for the waste management units handling such oil streams, for purposes of the Covered Refinery's TAB calculation and compliance with the applicable compliance option. If requested by EPA, ExxonMobil shall promptly submit revised schematics that reflect the Parties' agreements regarding the characterization of these oil streams and the appropriate control standards. ExxonMobil shall use these schematics in preparing the BWON Sampling Plans required under Paragraphs 108 and 109.

b. Non-Aqueous Benzene Waste Streams. All waste management units handling non-exempt, non-aqueous benzene wastes, as defined in Subpart FF, shall meet the applicable control standards of Subpart FF.

c. Aqueous Benzene Waste Streams. For purposes of calculating each Covered Refinery's TAB pursuant to the requirements of 40 C.F.R. § 61.342(a), ExxonMobil shall include all waste/slop/off-spec oil streams that become "aqueous" until such streams are recycled to a process or put into a process feed tank (unless the tank is used primarily for the storage of wastes). Appropriate adjustments will be made to such calculations to avoid the double-counting of benzene. For purposes of complying with the applicable compliance option, all waste management units handling benzene waste streams will either meet the applicable control standards of Subpart FF or will have their uncontrolled benzene quantity count toward the applicable limit under the 2 Mg Compliance Option or the 6 BQ Compliance Option.

108. **Sampling Under the 6 BQ Compliance Option**. ExxonMobil shall conduct quarterly sampling as described by this Paragraph at the Baytown, Billings, Joliet and Torrance Refineries for the purpose of calculating quarterly, uncontrolled benzene quantities.

a. By no later than 180 days after the Entry Date, ExxonMobil shall submit to EPA for approval a sampling plan for each such Refinery designed to identify the quarterly benzene quantity in uncontrolled benzene waste streams, including waste/slop/off-spec oil. That sampling plan (the "BWON Sampling Plan") shall include, but need not be limited to:
(i) proposed sampling locations and methods for flow calculations at the "end of line" of uncontrolled benzene waste streams; (ii) a simplified flow diagram that identifies significant,

uncontrolled benzene waste streams that feed into each proposed sampling location; (iii) proposed quarterly sampling, at the "point of waste generation," of each waste stream that contributes 0.05 Mg/yr or more to the Refinery's benzene quantity; and (iv) quarterly sampling at all "end of line" and point of waste generation locations identified in Subparagraphs 108.a.(i) and 108.a.(iii). The BWON Sampling Plans may identify commingled, exempt waste streams for sampling, provided ExxonMobil demonstrates that the benzene quantity of those commingled streams will not be underestimated. Additionally, waste streams that are non-aqueous at their point of generation and do not become aqueous thereafter shall not be included in the BWON Sampling Plans.

b. If changes in processes, operations, or other factors lead ExxonMobil to conclude that its approved BWON Sampling Plan no longer provides an accurate measure of the Refinery's quarterly benzene quantity in uncontrolled benzene waste streams, ExxonMobil shall submit a revised BWON Sampling Plan to EPA for approval.

c. ExxonMobil shall commence sampling under its BWON Sampling Plan during the first full calendar quarter following submittal of the Plan, regardless of whether or not the Plan is approved at that time. ExxonMobil shall take, and have analyzed, at least three representative samples from each identified sampling location. ExxonMobil shall use the average of all samples taken and the identified flow calculations to determine its quarterly benzene quantity in uncontrolled waste streams and to estimate a calendar year value for the Refinery.

109. **Sampling Under the 2 Mg Compliance Option**. ExxonMobil shall conduct quarterly sampling as described by this Paragraph at the Baton Rouge and Beaumont Refineries for the purpose of calculating quarterly, uncontrolled benzene quantities

a. By no later than 180 days after the Entry Date, ExxonMobil shall submit to EPA for approval a sampling plan for each such Refinery designed to identify the quarterly benzene quantity in uncontrolled benzene waste streams, including waste/slop/off-spec oil. That sampling plan (the "BWON Sampling Plan") shall include, but need not be limited to: (i) proposed sampling locations and methods for flow calculations at the "end of line" of uncontrolled benzene waste streams; (ii) quarterly sampling of all uncontrolled waste streams that count toward the 2 Mg/yr calculation an contain greater than 0.05 Mg/yr of benzene; (iii) monthly sampling of all uncontrolled waste streams that qualify for the 10 ppmw exemption (40 C.F.R. § 61.342(c)(2)) and that contain greater than 0.1 Mg/yr of benzene. The BWON Sampling Plans may identify commingled, exempt waste streams for sampling, provided ExxonMobil demonstrates that the benzene quantity of those commingled streams will not be underestimated.

b. If changes in processes, operations, or other factors lead ExxonMobil to conclude that its approved BWON Sampling Plan may no longer provide an accurate measure of the Refinery's quarterly benzene quantity in uncontrolled benzene waste streams, ExxonMobil shall submit a revised BWON Sampling Plan to EPA for approval.

c. ExxonMobil shall commence sampling under its BWON Sampling Plan during the first full calendar quarter following submittal of the Plan, regardless of whether or not the Plan is approved at that time. ExxonMobil shall take, and have analyzed, at least three representative samples from each identified sampling location. ExxonMobil shall use the average of all samples taken and the identified flow calculations to determine its quarterly benzene quantity in uncontrolled waste streams and to estimate a calendar year value for the Refinery.

d. After at least 8 quarters of sampling under an approved BWON Sampling Plan under this Paragraph 109, ExxonMobil may submit a report to EPA and the Applicable Co-Plaintiff that requests a change in the monitoring frequency specified by Subparagraph 109.a for one or more of the Covered Refineries. If EPA determines, after an opportunity for consultation with ExxonMobil and the Applicable Co-Plaintiff, that the information presented in the report supports a change in the monitoring frequency for one or more of the Covered Refineries, then the monitoring frequency requirement under Subparagraph 109.a will be modified in accordance with Paragraph 269 (Modifications).

110. **Quarterly and Annual Estimations of Uncontrolled Benzene Quantity**. At the end of each calendar quarter following commencement of quarterly sampling, ExxonMobil shall calculate a quarterly uncontrolled benzene quantity and shall estimate a projected calendar year uncontrolled benzene quantity based on the quarterly end of line sampling results, non-end of line sampling results, and the approved flow calculations. ExxonMobil shall submit the uncontrolled benzene quantity in the Semi-Annual Reports due under Section IX of this Decree.

111. **Corrective Measures**.

a. Applicability

(1) For 6 BQ Compliance Option Refineries. If the calculations in Paragraph 110 indicate that the quarterly uncontrolled benzene quantity at the Baytown, Billings, Joliet, or Torrance Refineries exceeds 1.5 Megagrams or the projected calendar year uncontrolled benzene quantity exceeds 6.0 Megagrams, ExxonMobil shall submit a written report to EPA and the Applicable Co-Plaintiff that evaluates all relevant information and identifies whether any action should be taken to reduce benzene quantities in its waste streams for the remainder of the calendar year. If additional

actions are determined to be necessary to ensure compliance with the 6 BQ Compliance Option, ExxonMobil will include in its written report a BWON Corrective Measures Plan as specified in Subparagraph 111.b

(2) For 2 Mg Compliance Option Refineries. If the calculations in Paragraph 110 indicate that the quarterly uncontrolled benzene quantity exceeds 0.5 Megagrams or the projected calendar year uncontrolled benzene quantity exceeds 2.0 Megagrams, ExxonMobil shall submit a written report to EPA and the Applicable Co-Plaintiff that evaluates all relevant information and identifies whether any action should be taken to reduce benzene quantities in its waste streams for the remainder of the calendar year. If additional actions are determined to be necessary to ensure compliance with the 2 Mg Compliance Option, ExxonMobil will include in its written report a BWON Corrective Measures Plan as specified in Subparagraph 111.b

b. BWON Corrective Measures Plan. ExxonMobil shall, in any BWON Corrective Measures Plan required by this Paragraph, identify: (i) the cause of the potentially elevated benzene quantities; (ii) all corrective actions that ExxonMobil has taken or plans to take to ensure that the cause will not recur; and (iii) an appropriate strategy and schedule that ExxonMobil shall implement to ensure that ExxonMobil complies with the 6 BQ Compliance Option or the 2 Mg Compliance Option, as applicable. If a spill event is the main cause of the potentially elevated benzene quantities, the BWON Corrective Measures Plan will focus on the spill event and on future measures to minimize and address spills. ExxonMobil shall submit such plan and schedule, along with its report under Subparagraph 111.a, by no later than 60 days after the end of the Calendar Quarter in which one or more of the conditions specified in

Subparagraph 111.a is satisfied. ExxonMobil shall implement its BWON Corrective Measures Plan in accordance with the schedule provided therein.

c. Third-Party TAB Study and Compliance Review. After a second consecutive quarter in which at least one of the conditions in Subparagraph 111.a continues to exist at a Covered Refinery and ExxonMobil is not then able to identify the cause(s) and/or appropriate corrective measures to ensure compliance with the applicable compliance option, ExxonMobil shall retain a third-party contractor to undertake a comprehensive TAB study and compliance review ("Third-Party TAB Study and Compliance Review") at the relevant Refinery. By no later than the last day of the next following quarter, ExxonMobil shall submit a proposal to EPA that identifies the contractor, the contractor's scope of work, and the contractor's schedule for the Third-Party TAB Study and Compliance Review. Unless EPA disapproves or seeks modifications of the proposal within 30 days after its receipt, ExxonMobil shall authorize the contractor to commence work. ExxonMobil shall ensure that the work is completed in accordance with the schedule provided therein. No later than thirty (30) days after ExxonMobil receives the results of the Third-Party TAB Study and Compliance Review, ExxonMobil shall submit the results to EPA. After the report is submitted to EPA, ExxonMobil and EPA shall discuss informally the results of the Third-Party TAB Study and Compliance Review. No later than ninety (90) days after ExxonMobil receives the results of the Third-Party TAB Study and Compliance Review or at such other time as ExxonMobil and EPA may agree, ExxonMobil shall submit to EPA a plan and schedule for remedying any deficiencies identified in the Third-Party TAB Study and Compliance Review and any deficiencies that EPA identified following the Third-Party TAB Study and Compliance Review. Unless EPA disapproves or seeks modifications of the proposal within thirty (30) days after its receipt, ExxonMobil shall implement the remedial plan in accordance with the schedule included in its plan.

112. **Miscellaneous Measures.**

a. By no later than 60 days after the Entry Date, ExxonMobil shall:

i. Conduct monthly visual inspections of and, if appropriate, refill all Subpart FF water traps within the Covered Refineries' individual drain systems;

ii. If ExxonMobil utilizes conservation vents, visually inspect all Subpart FF conservation vents or indicators on process sewers for detectable leaks on a weekly basis, reset any vents where leaks are detected, and record the results of the inspections. After two (2) years of weekly inspections, and based upon an evaluation of the recorded results, ExxonMobil may submit a request to the appropriate EPA Region to modify the frequency of the inspections. EPA shall not unreasonably withhold its consent to such modification. Alternatively, for conservation vents with indicators that identify whether flow has occurred, ExxonMobil may elect to visually inspect such indicators on a monthly basis and, if flow is then detected, ExxonMobil shall then visually inspect that indicator on a weekly basis for four weeks. If flow is detected during any two of those four weeks, ExxonMobil shall install a carbon canister on that vent until appropriate corrective action(s) can be implemented to prevent such flow. Nothing in this Subparagraph shall require ExxonMobil to monitor conservation vents on fixed roof tanks; and

iii. Conduct quarterly monitoring and repair of the oil-water separators consistent with the "no detectable emissions" provision in 40 C.F.R. § 61.347.

b. By no later than 150 days after the Entry Date, ExxonMobil shall identify and mark at the drain all area drains that are segregated stormwater drains.

113. **Recordkeeping and Reporting Requirements for this Subsection V.N: Outside of the Reports Required under 40 C.F.R. § 61.357 and the Semi-Annual Reports Required by Section IX (Recordkeeping and Reporting).** At the times specified in the applicable provisions of this Section V.N, ExxonMobil will submit, as and to the extent required, the following reports to EPA and the Applicable Co-Plaintiff:

i. BWON Compliance Review and Verification Reports (under Subparagraph 100.a), as amended, if necessary (under Subparagraph 100.b);

ii. Amended TAB Reports, if necessary (under Subparagraph 101.a);

iii. BWON Corrective Measures Plans, if necessary (under Subparagraph 101.b and/or Paragraph 111);

iv. Certifications of Compliance, if necessary (under Subparagraph 101.d);

v. Reports certifying the completion of installation of dual carbon canisters (under Subparagraph 102.a);

vi. Schematics of waste/slop/off-spec oil movements, as revised, if necessary (under Subparagraph 107.a); and

vii. BWON Sampling Plans (under Subparagraphs 108.a and 109.a), and revised BWON Sampling Plans, if necessary (under Subparagraphs 108.b and 109.b).

114. **Recordkeeping and Reporting Requirements for this Subsection V.N: As Part of the Semi-Annual Reports Required by Section IX (Recordkeeping and Reporting).** ExxonMobil shall submit the following information in the Semi-Annual Reports submitted pursuant to Section IX (Reporting and Recordkeeping) for the six month period covered by the Report:

i. An identification of all laboratory audits, if any, completed during the six month period, including a description of the methods used in the audit and the results of the audit;

ii. A description of the measures taken, if any, during the six month period to comply with the training provisions of Paragraph 106; and

iii. A summary of the sampling results required under Paragraph 108, including the quarterly and projected annual uncontrolled benzene quantities or TAB, as applicable.

O. LEAK DETECTION AND REPAIR PROGRAM ENHANCEMENTS.

115. In order to minimize or eliminate fugitive emissions of volatile organic compounds ("VOCs"), benzene, volatile hazardous air pollutants ("VHAPs"), and organic

hazardous air pollutants ("HAPs") from equipment in light liquid and/or in gas/vapor service, ExxonMobil shall undertake the enhancements identified in this Subsection V.O to its leak detection and repair ("LDAR") programs for each of the Covered Refineries under 40 C.F.R. Part 60, Subpart GGG; Part 61, Subparts J and V; Part 63, Subparts F, H, and CC; and applicable state and local LDAR requirements. The terms "equipment," "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 GGG; Part 61, Subparts J and V; Part 63, Subparts F, H and CC; and applicable state and local LDAR regulations.

116. **Applicability of NSPS Subpart GGG to Process Units at the Covered Refineries.**

a. Covered Refineries Other than the Billings Refinery. As of the Entry Date for each of the Covered Refineries other than the Billings Refinery each existing "process unit" (as defined by 40 C.F.R. § 60.591) at each of those Covered Refineries shall become an "affected facility" for purposes of 40 C.F.R. Part 60, Subpart GGG, and shall become subject to and comply with the requirements of 40 C.F.R. Part 60, Subpart GGG, and the requirements of this Subsection V.O.

b. Billings Refinery.

(1) ExxonMobil shall comply with the requirements of 40 C.F.R. Part 60, Subpart GGG, and the requirements of this Subsection V.O at each existing "process unit" (as defined by 40 C.F.R. § 60.591) at the Billings Refinery by no later than 180 days after the Entry Date; provided, however, that ExxonMobil shall have two years from the Entry Date to comply with the standards for sampling connection systems set forth at 40 C.F.R. § 60.482-5.

(2) Two years after the Entry Date, each existing process unit at the Billings Refinery shall become an affected facility for purposes of Subpart GGG, and shall become subject to and comply with the requirements of 40 C.F.R. Part 60, Subpart GGG, and the requirements of this Subsection V.O, including the standards for sampling connection systems set forth at 40 C.F.R. § 60.482-5.

c. For the purposes of this Consent Decree, each process unit covered under this Paragraph shall be deemed to have become an affected facility for purposes of Subpart GGG under the provisions of 40 C.F.R. § 60.14 or § 60.15. These provisions specifically apply for the purposes of qualifying such affected facilities for any exemptions provided under 40 C.F.R. §§ 60.482-3(j), 60.482-7(h)(2), 60.482-10(k)(2), and 60.593(c).

d. For process units that become affected facilities for purposes of Subpart GGG pursuant to this Paragraph 116 , entry of this Consent Decree shall satisfy applicable notification requirements of 40 C.F.R. § 60.7(a).

117. **<u>Written Refinery-Wide LDAR Program Descriptions</u>**. By no later than 180 days after the Entry Date, ExxonMobil shall develop and maintain a set of written LDAR Program Descriptions for a program for compliance with all federal, state, and local LDAR regulations applicable to each of the Covered Refineries. ExxonMobil shall update the LDAR Program Descriptions as may be necessary to ensure continuing compliance. The LDAR Program Descriptions shall include, at a minimum:

i. A set of leak rate goals for each Covered Refinery that will be a target for achievement on a process-unit-by-process-unit basis. Such targets shall have the purpose of facilitating lower leak rates and are not intended to be enforceable requirements;

ii. An identification of all equipment in light liquid and/or in gas/vapor service that is subject to periodic monitoring requirements via Method 21 under any applicable federal, state, or local LDAR regulation and that has the potential to leak VOCs, HAPs, VHAPs, and benzene within each Covered Refinery's process units;

iii. Procedures for identifying leaking equipment within each Covered Refinery's process units;

iv. Procedures for repairing and keeping track of leaking equipment;

v. Procedures for identifying and including new equipment to be added to the LDAR program;

vi. A process for evaluating new and replacement equipment to promote consideration and installation of equipment that will minimize leaks and/or eliminate chronic leakers;

vii. A description of each Covered Refinery's LDAR monitoring organization and a designation of the person or position responsible for LDAR management and has the authority to implement LDAR improvements at the Refinery, as required by Paragraph 119; and

viii. A procedure for regularly communicating LDAR information to appropriate ExxonMobil personnel.

118. **Training.** By no later than 180 days after the Entry Date, ExxonMobil shall begin to implement a training program at each Covered Refinery which includes the following features:

i. For personnel newly-assigned to LDAR responsibilities, ExxonMobil shall require LDAR training prior to each employee beginning such work;

ii. For all personnel assigned LDAR responsibilities, ExxonMobil shall provide and require completion of annual LDAR training or require its LDAR contractor to provide such training (initial annual LDAR training for all such personnel will be completed not later than one year after the Entry Date);

iii. For all other Refinery operations and maintenance personnel (including contract personnel) who have duties relevant to LDAR, ExxonMobil shall provide and require completion of an initial training program that includes instruction on aspects of LDAR that are relevant to the person's duties (initial LDAR training for all such personnel will be completed not later than one year after the Entry Date); and

iv. For the individuals covered by this Paragraph, "refresher" training in LDAR shall be performed on a cycle of no longer than three years.

119. **LDAR Personnel**. By no later than 180 days after the Entry Date, ExxonMobil shall establish a program that holds each person assigned LDAR responsibilities accountable for LDAR performance. By no later than 180 days after the Entry Date, ExxonMobil shall establish and maintain a person or position at each Covered Refinery with responsibility for LDAR management and authority to implement LDAR improvements at the Refinery.

120. **LDAR Audits**. ExxonMobil shall implement Refinery-wide LDAR Audits – including an Initial LDAR Audit and Regular LDAR Audits – as set forth in this Paragraph to ensure each Covered Refinery's compliance with all applicable LDAR requirements. Each LDAR Audit shall include, but shall not be limited to: (i) performing comparative monitoring; (ii) reviewing records to ensure monitoring and repairs were completed in the required periods; (iii) reviewing component identification procedures, tagging procedures, and data management procedures; and (iv) observing LDAR technicians' calibration and monitoring techniques. During each LDAR Audit, leak rates shall be calculated for each process unit where comparative monitoring was performed.

a. Initial LDAR Audit. ExxonMobil shall retain a third-party contractor to complete an Initial LDAR Audit for each Covered Refinery by no later than 365 days after the Entry Date.

b. Initial Audit Report. Within 90 days of completion of the Initial Audit, ExxonMobil shall submit an Initial Audit Report to the EPA and the Applicable Co-Plaintiff. The Report shall describe the results of the Initial Audit, disclose all areas of identified non-compliance, and certify ExxonMobil's compliance, except for the identified deficiencies. The

Report shall also include a schedule for correcting any identified deficiencies as soon as practicable.

c. Regular LDAR Audits.

(1) Third-Party Audits. ExxonMobil shall retain a contractor to perform a Third-Party LDAR Audit of each Covered Refinery's LDAR program at least once every four (4) calendar years after the Initial LDAR Audit is completed under Subparagraph 120.a (with approximately 48 months between the Audits).

(2) Internal Audits. ExxonMobil shall conduct Internal LDAR Audits of each Covered Refinery's LDAR program by sending personnel familiar with the LDAR program and its requirements from one or more of ExxonMobil's other Covered Refineries or locations to audit another Covered Refinery. ExxonMobil shall complete an Internal LDAR Audit by no later than two (2) years from the date of the completion of the third-party audits required in Subparagraphs 120.a and 120.c.(1). ExxonMobil will perform an Internal Audit of each Covered Refinery's LDAR program at least once every four (4) calendar years (with approximately 48 months between the Audits). ExxonMobil may elect to retain third-parties to undertake an Internal Audit, provided that a Regular LDAR Audit at each Covered Refinery occurs every two (2) years.

(3) Timing. To ensure that an LDAR Audit occurs every two (2) years at each Covered Refinery, once a Refinery's Initial Audit is completed, the remaining Third-Party Audits and Internal Audits at that Refinery shall be separated by not more than two (2) calendar years (with approximately 24 months between the Audits).

121. **Implementation of Actions Necessary to Correct Non-Compliance**. If the results of any of the LDAR Audits conducted pursuant to Paragraph 120 identify any areas of noncompliance, ExxonMobil shall implement, as soon as practicable, all steps necessary to correct or otherwise address such area(s) of non-compliance and to prevent, to the extent practicable, a recurrence of the cause of such non-compliance. ExxonMobil shall, during the term of this Consent Decree, retain the Initial Audit Report and all other LDAR Audit reports generated pursuant to Paragraph 120, and shall maintain a written record of all corrective actions that ExxonMobil takes in response to deficiencies identified in any LDAR Audits. After the completion of any LDAR Audit other than the Initial Audit, ExxonMobil shall include the following information in the next Semi-Annual Report due under Section IX of this Consent Decree: (i) a summary, including findings, of each such LDAR Audit; and (ii) a list of corrective actions taken during the reporting period, and any schedule for implementing future corrective actions.

122. **Internal Leak Definition for Valves and Pumps**. ExxonMobil shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions.

a. Leak Definition for Valves**.** By no later than 365 days after the Entry Date for each Covered Refinery other than the Billings Refinery, and by no later than two (2) years after the Entry Date for the Billings Refinery, ExxonMobil shall utilize an internal leak definition of 500 ppm VOCs for valves in light liquid and/or gas/vapor service at Covered Refineries, excluding pressure relief devices.

b. Leak Definition for Pumps. By no later than 365 days after the Entry Date for each Covered Refinery other than the Billings Refinery, and by no later than two (2) years after the Entry Date for the Billings Refinery, ExxonMobil shall utilize an internal leak definition of 2000 ppm for centrifugal pumps at the Covered Refineries. Reciprocating pumps, connectors, compressors, and other components shall retain their applicable regulatory leak definition.

123. **LDAR Monitoring Frequency.**

a. Pumps. When the lower internal leak definition for pumps becomes applicable under Paragraph 122, and unless more frequent monitoring is required by applicable federal, state and/or local requirements, ExxonMobil shall monitor pumps at the internal leak definition on a monthly basis.

b. Valves. When the lower internal leak definition for valves becomes applicable under Paragraph 122, and unless more frequent monitoring is required by applicable federal, state and/or local requirements, ExxonMobil shall monitor valves (other than difficult to monitor or unsafe to monitor valves) at the internal leak definition on a quarterly basis, with no ability to skip periods on a process-unit-by-process-unit basis.

124. **Reporting, Recording, Tracking, Repairing and Remonitoring Leaks of Valves and Pumps Based on the Internal Leak Definitions**.

a. Reporting. For regulatory reporting purposes, ExxonMobil may continue to report leak rates in valves and pumps against the applicable regulatory leak definition, or may use the lower, internal leak definitions specified in Paragraph 122.

b. Recording, Tracking, Repairing and Remonitoring Leaks. ExxonMobil shall record, track, repair, and re-monitor all leaks in excess of the internal leak definitions of Paragraph 122 (at such time as those definitions become applicable). Except as provided otherwise in this Subsection V.O, ExxonMobil shall make a first attempt at repair and remonitor the component within five (5) calendar days after a leak is detected and either complete repairs and re-monitor leaks or place such component on the Covered Refinery's delay of repair list according to Paragraph 130 within thirty (30) days after a leak is detected.

125. **Monitoring After Turnaround or Maintenance.** ExxonMobil shall have the option of monitoring affected valves and pumps within process unit(s) after completing a documented maintenance, startup, or shutdown activity, and that monitoring activity shall not count as a scheduled monitoring activity for any components found to be leaking at a level between the internal leak definition and the applicable regulatory definition, provided that ExxonMobil monitors according to the following schedule:

i. For events involving 1000 or fewer valves and pumps, monitor within one (1) week of the documented maintenance, startup, or shutdown activity;

ii. For events involving greater than 1000 but fewer than 5000 valves and pumps, monitor within two (2) weeks of the documented maintenance, startup, or shutdown activity; and

iii. For events involving greater than 5000 pumps and valves, monitor within four (4) weeks of the documented maintenance, startup, or shutdown activity.

126. **Initial Attempt at Repair on Certain Valves.** Beginning no later than 180 days after the Entry Date for each Covered Refinery other than the Billings Refinery, and beginning no later than two (2) years after the Entry Date for the Billings Refinery, ExxonMobil shall promptly make a "initial attempt" at repair after detecting a leak at a reading greater than 200 ppm of VOCs at any valve, excluding pressure relief devices, control valves, valves that are on the delay of repair list, and components that LDAR personnel are not authorized to repair. ExxonMobil or its designated contractor shall re-monitor the valve in question within five (5) calendar days after the "initial attempt" to repair. If the re-monitored leak reading is below the applicable leak definition, no further action will be necessary. If the re-monitored leak reading is

greater than the applicable leak definition, ExxonMobil shall repair the valve according to the requirements of Subparagraph 124.b, except that no first repair attempt requirement shall apply. If ExxonMobil can demonstrate with sufficient, statistically significant monitoring data over a period of at least two years that "initial attempts" to repair at 200 ppm worsen or do not improve refinery leak rates, ExxonMobil may request EPA to reconsider or amend this requirement.

127. **Electronic Monitoring, Storing, and Reporting of LDAR Data**.

a. Electronic Storing and Reporting of LDAR Data. ExxonMobil has and shall continue to maintain an electronic database for storing and reporting LDAR data at each of the Covered Refineries.

b. Electronic Data Collection During LDAR Monitoring and Transfer Thereafter. By no later than 90 days after the Entry Date for each Covered Refinery other than the Billings Refinery, and by no later than 150 days after the Entry Date for the Billings Refinery, ExxonMobil shall use data loggers and/or electronic data collection devices during all LDAR monitoring at the Covered Refineries. ExxonMobil, or its designated contractor, shall use its best efforts to transfer, by the end of the next business day, the electronic data from electronic data logging devices to the electronic database maintained pursuant to Subparagraph 127.a. For all monitoring events in which an electronic data collection device is used, the collected monitoring data shall include a time and date stamp, and identification of the instrument and operator. ExxonMobil may only use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when data loggers are unavailable or broken), and shall record, at a minimum, the identity of the technician, the date, the monitoring starting and ending times, all monitoring readings, and an identification of the monitoring equipment. ExxonMobil shall use its best efforts to transfer any manually recorded monitoring data to the electronic database maintained pursuant to Subparagraph 127.a within seven (7) days of the monitoring event.

128. **<u>QA/QC of LDAR Data</u>.** By no later than 90 days after the Entry Date for each Covered Refinery other than the Billings Refinery, and by no later than 150 days after the Entry Date for the Billings Refinery, ExxonMobil (or a third-party contractor retained by ExxonMobil) shall develop and implement procedures for quality assurance/quality control ("QA/QC") reviews of all data generated by LDAR monitoring technicians. ExxonMobil shall ensure that monitoring data provided by monitoring technicians is reviewed daily for QA/QC. At least once per calendar quarter, ExxonMobil shall perform a QA/QC review of each contractor's monitoring data which shall include, but not be limited to, a review of: (i) the number of components monitored per technician; (ii) the time between monitoring events; and (iii) abnormal data patterns.

129. **<u>Calibration/Calibration Drift Assessment</u>.**

a. <u>Calibration</u>. ExxonMobil shall conduct all calibrations of LDAR monitoring equipment at each of the Covered Refineries using methane as the calibration gas, and in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21.

b. <u>Calibration Drift Assessment</u>. By no later than 365 days after the Entry Date, ExxonMobil shall conduct calibration drift assessment re-checks of the LDAR monitoring equipment at least twice during each monitoring shift, with one such re-check being at the end of the monitoring shift. ExxonMobil shall conduct the calibration drift assessment re-check using a calibration gas 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, ExxonMobil shall remonitor all valves that were monitored since the last calibration or calibration drift assessment that had a reading greater than 100 ppm and shall remonitor all pumps that were monitored since the last calibration or calibration drift assessment that had a reading greater than 500 ppm.

130. **Delay of Repair**.

a. By no later than 90 days after the Entry Date, ExxonMobil shall take the following actions for any equipment at any Covered Refinery that ExxonMobil intends to place on the "delay of repair" list, under applicable regulations:

i. ExxonMobil shall require sign-off by the unit supervisor, within thirty (30) days of identifying that a piece of equipment is leaking at a rate greater than the applicable leak definition, that such equipment qualifies for delayed repair under applicable regulations;

ii. ExxonMobil shall include equipment that is placed on the "delay of repair" list in ExxonMobil's regular LDAR monitoring;

iii. ExxonMobil shall use its best efforts to isolate and repair centrifugal pumps identified as leaking at a rate of 2000 ppm or greater; and

iv. For valves (other than control valves and pressure relief devices) leaking at 10,000 ppm or greater and which cannot be repaired using traditional techniques, ExxonMobil shall use the "drill and tap" repair method (or an equivalent repair method) for the leaking valve (unless the valve is isolated from the process and does not remain in VOC service), prior to placing the valve on the delay of repair list, unless ExxonMobil can demonstrate that there is a safety, mechanical, or major environmental concern posed by repairing the leak in that manner. If not repaired within 15 days by other means, ExxonMobil shall perform the first "drill and tap" (or equivalent repair method) within 15 days, and a second attempt (if necessary) within 30 days after the leak is detected. After two unsuccessful attempts to repair a leaking valve through the "drill and tap" (or equivalent) method, ExxonMobil may place the leaking valve on its "delay of repair" list. The requirement to make two attempts to repair a leaking component by the drill and tap method may be satisfied by making two sealant injection attempts rather than by making multiple taps into the valve body.

b. If a new valve repair method not currently in use by the refining industry is planned to be used by ExxonMobil in lieu of the "drill and tap" method referenced in the preceding Subparagraph, ExxonMobil shall advise EPA prior to implementing such a method or, if prior notice is not practicable, as soon as practicable after implementation.

131. **Chronic Leakers.** A valve shall be classified as a "chronic leaker" under this Paragraph if it leaks above 5,000 ppm twice in any consecutive four quarters after the Entry Date, unless the valve has not leaked in the twelve (12) consecutive quarters prior to the relevant process unit turnaround. Following the identification of a "chronic leaker" non-control valve, ExxonMobil shall replace, repack, or perform similarly effective repairs on the chronic leaker during the next process unit turnaround occurring 180 days after the after the Entry Date.

132. **Alternate Leak Detection Method**. With EPA's prior written approval, ExxonMobil may begin using an alternate leak detection method – such as a method employing "Smart LDAR" technology – based on a showing that the alternate leak detection method is equivalent to traditional monitoring methods and is allowable under the applicable LDAR regulations. If necessary to implement this Paragraph, the Parties shall make appropriate modifications to this Consent Decree in accordance with Paragraph 269.

133. **Recordkeeping and Reporting Requirements for this Section**.

a. In the Semi-Annual Reports submitted by ExxonMobil pursuant to Section IX (Recordkeeping and Reporting), ExxonMobil shall include the following information in the Report for the period in which the identified activity occurred or was required:

i. A copy of each Covered Refinery's LDAR Program Description under Paragraph 117;

ii. A certification that each Covered Refinery's training program has been implemented as required by Paragraph 118;

iii. An identification of the person or position at each Covered Refinery responsible for LDAR performance as required by Paragraph 119;

iv. A certification that the lower leak definitions and increased monitoring frequencies have been implemented according to Paragraphs 122 and 123;

v. A certification of the implementation of the "initial attempt" to repair program under Paragraph 126;

vi. A certification of the implementation of QA/QC procedures for review of data generated by LDAR technicians as required by Paragraph 128;

vii. A certification of the implementation of the calibration drift assessment procedures of Paragraph 129; and

viii. A certification of the implementation of the "delay of repair" procedures of Paragraph 130.

b. Special Requirement for Initial Semi-Annual Report Each Year. As part of the first Semi-Annual Report submitted each year pursuant to Section IX (Recordkeeping and Reporting), ExxonMobil shall identify each LDAR Audit that was conducted at each Covered Refinery under Paragraph 120 in the previous calendar year, including an identification of the auditors, a summary of the audit results, and the actions that ExxonMobil took or intends to take to correct identified deficiencies.

c. Reports Due Under 40 C.F.R. § 63.654. In each report due under 40 C.F.R. § 63.654, ExxonMobil shall include the following information on LDAR monitoring at the relevant Covered Refinery:

i. a list of the process units monitored during the reporting period;

ii. the number of valves and pumps present in each process unit;

iii. the number of valves and pumps monitored in each process unit;

iv. the number of valves and pumps found leaking for each process unit;

v. the number of "difficult to monitor" pieces of equipment monitored;

vi. the projected month and year of the next monitoring event for that unit;

vii. a list of all equipment currently on the “delay of repair” list and the date each component was placed on the list;

viii. the number of repairs not attempted within five (5) days and thirty (30) days pursuant to Subparagraph 124.b;

ix. the number of initial attempts at repair not made promptly and remonitored within five (5) days pursuant to Paragraph 126;

x. the number of repairs not completed at the next process unit turnaround pursuant to Paragraph 131; and

xi. the number of repairs not completed within fifteen (15) days and thirty (30) days under Subparagraph 130.a.iv.

P. OTHER COMPLIANCE PROGRAM REQUIREMENTS APPLICABLE TO THE BILLINGS AND JOLIET REFINERIES.

134. Joliet Wastewater Treatment Plant Area Program Requirements. ExxonMobil shall comply with the Joliet Wastewater Treatment Plant Area Program requirements specified in Appendix P to this Consent Decree.

135. Joliet Material Staging Area.

a. By no later than the Entry Date, ExxonMobil shall use the Material Staging Area (also known as the BRU Decant Pad) at the Joliet Refinery primarily for management of oil-bearing hazardous secondary materials subject to 40 C.F.R. § 261.4(a)(12) and Ill. Admin. Code tit. 35, § 721.104(a)(12)(A)-, and shall not use the Material Staging Area for treatment, storage or disposal of materials that meet the definition of hazardous waste under 40 C.F.R. § 261.3 and Ill. Admin Code tit. 35, § 721.103. The location of the Material Staging Area is identified on the drawing attached as Appendix T to this Consent Decree.

b. As provided by 40 C.F.R. § 261.4(a)(12) and Ill. Admin. Code tit. 35, § 721.104(a)(12)(A), oil-bearing hazardous secondary materials transferred to the Material

Staging Area shall not be placed on the land and shall not be accumulated speculatively before being recycled.

c. ExxonMobil shall clean the Material Staging Area bays to remove hydrocarbon residue as required by usage, but no less than once every 90 days. Whenever the bays are cleaned, ExxonMobil shall inspect the areas around the Material Staging Area to confirm that oil-bearing hazardous secondary materials have not been released from the Material Staging Area.

d. As provided by 40 C.F.R. § 261.4(a)(12) and Ill. Admin. Code tit. 35, § 721.104(a)(12)(A), any residuals generated from processing or recycling oil-bearing hazardous secondary materials at the Material Staging Area that are disposed of or intended for disposal shall be designated and managed as F037 listed wastes when they are removed from the Material Staging Area. If any oil-bearing hazardous secondary materials are released from the Material Staging Area and not immediately recovered for use in a refining process, then ExxonMobil shall designate and manage such released materials as F037 listed wastes.

e. If ExxonMobil uses the Material Staging Area for management of waste materials that do not meet the definition of hazardous waste under 40 C.F.R. § 261.3 and Ill. Admin Code tit. 35, § 721.103, then ExxonMobil shall segregate such waste materials and shall not commingle such waste materials with any oil-bearing hazardous secondary materials.

f. ExxonMobil shall establish and implement written procedures designed to ensure that the Material Staging Area is used only for management of materials described in Subparagraphs 135.a and 135.e. The procedures shall include use of a written form to document all material transfers to the Material Staging Area, including an indication of the material type, the material quantity, the source of the material, the request and authorization dates, and the names of the requester and the individual authorizing the transfer at the Joliet Refinery ("Material Staging Area Transfer Forms"). With each WWTP Area Wastewater Monitoring Plan Quarterly Report required under Paragraph 4 of Consent Decree Appendix P, ExxonMobil shall include a copy of each Material Staging Area Transfer Form completed and used for the transfer of material to the Material Staging Area during that quarterly period. With the WWTP Area Wastewater Monitoring Plan Final Report, ExxonMobil shall include a copy of each Material Staging Area Transfer Form completed and used for the transfer of material to the Material Staging Area for the final quarter of the Monitoring Period.

g. As required by 40 C.F.R. § 261.2(f) and Ill. Admin. Code tit. 35, § 721.102(f), ExxonMobil shall maintain appropriate documentation demonstrating that oil-bearing hazardous secondary materials are being managed in the Material Staging Area in accordance with all requirements imposed by 40 C.F.R. § 261.4(a)(12) and Ill. Admin. Code tit. 35, § 721.104(a)(12)(A).

136. Joliet RCRA Training Requirements. By no later than the Entry Date, ExxonMobil shall provide to EPA for review and comment a copy of the following:

i. The syllabus for the Joliet Refinery's current RCRA training program given to all Refinery employees involved in hazardous waste management at the Joliet Refinery;

ii. Completion records from employee RCRA training sessions held at the Joliet Refinery during calendar years 2003 and 2004; and

iii. The procedure that will be used at the Joliet Refinery to ensure that contractors who perform work at the Joliet Refinery that involves the management of hazardous waste have had RCRA training.

137. Billings Refinery Scrap Yard and Laydown Areas.

a. Within 90 days of the Entry Date, ExxonMobil shall designate both the Scrap Yard and the Laydown Areas (the precise location and area of the Scrap Yard and the Laydown Areas is defined in the drawing attached to this Consent Decree as Appendix S) as Solid Waste Management Units and/or Areas of Concern under the current Billings Refinery RCRA permit (Montana Hazardous Waste Permit, MTHWP-99-02). Pursuant to the Montana administered RCRA program ExxonMobil shall complete a RCRA Corrective Action process for the Scrap Yard and Laydown Areas, including investigating the nature and extent of all releases (including, but not limited to, releases from heat exchanger bundles), and performing necessary remediation, if any.

b. ExxonMobil shall submit to EPA all documentation related to: (1) the designation of the Scrap Yard and the Laydown Areas as Solid Waste Management Units and/or Areas of Concern; and (2) any subsequent corrective action at the Scrap Yard and the Laydown Areas. The information shall be submitted to EPA at the same time the information is submitted to the Applicable Co-Plaintiff.

c. Within 90 days of the Entry Date, ExxonMobil shall propose to EPA for review and approval modifications to its Billings Stormwater Pollution Prevention Plan ("SWPPP") including:

i. Standard operating procedures to assure that no hazardous wastes, as defined by RCRA, are placed in the Scrap Yard and the Laydown Areas;

ii. A comprehensive list of the types of material that may be placed in Scrap Yard and Laydown Areas; and

iii. Assigning direct responsibility for compliance with the new standard operating procedures regarding the Scrap Yard and the Laydown Areas and for all other SWPPP elements to an ExxonMobil employee.

Within 60 days of EPA's approval of the modification of the Billings SWPPP, ExxonMobil shall revise its SWPPP to incorporate the approved provisions.

138. Billings Refinery Land Treatment Unit. Within 90 days of the Entry Date, ExxonMobil shall submit to EPA for review and approval proposed amendments to its Billings Refinery RCRA permit (Montana Hazardous Waste Permit, MTHWP-99-02) related to waste application at the Land Treatment Unit (the precise location and area of the Land Treatment Unit is defined in the drawing attached to the Consent Decree as Appendix S). The proposed revisions shall include:

i. A prohibition against waste application at the Land Treatment Unit when either: (1) the average hourly wind speed exceeds 10 mph for any 15 consecutive minute period, or (2) when maximum daily gusts exceed 20 mph for a 5 consecutive minute period; provided, however that waste application may be resumed if the conditions in (1) and (2) have not occurred for a period of 60 consecutive minutes prior to the time of resumption of waste application;

ii. A requirement to maintain a system capable of measuring and transmitting wind conditions at the Refinery to ExxonMobil personnel necessary for compliance with the prohibition set forth in Subparagraph 138.i; and

iii. Standard operating procedures to assure compliance with the soil moisture requirements applicable to the Land Treatment Unit (Montana Hazardous Waste Permit, MTHWP-99-02, Section III.a.E.7).

139. Billings Refinery Outfall 002.

a. Within 90 days of the Entry Date, ExxonMobil shall propose to EPA for review and approval draft amendments to the oil sheen provisions for Outfall 002 of its Billings Refinery Montana Pollutant Discharge Elimination System Permit ((MPDES)(MT-0000477)), including:

i. A detailed procedure for the monitoring and detection of oil sheen events, including but not limited to, the use of an infrared monitoring system or equivalent;

ii. Requirements for maintaining proper calibration of sheen detection equipment, including, but not limited to, the infrared monitoring system or equivalent; and

iii. Formal procedures for investigating the cause of oil sheen exceedances that reach the river.

b. Upon EPA approval of the proposed MPDES Outfall 002 oil sheen permit modifications, ExxonMobil shall within 60 days submit an application to the Applicable Co-Plaintiff to include the modifications in the Billings Refinery MPDES permit.

140. Billings Refinery Tank 350.

a. By no later than 90 days after the Entry Date, ExxonMobil shall discontinue placement of wastewater and/or other material in Billings Refinery Tank 350 using trucks or other non-piped methods ("Non-Piped Tank 350 Inflow").

b. Within 90 days of the Entry Date, ExxonMobil shall propose to EPA for review and approval a draft amendment to its Billings Refinery Montana Pollutant Discharge Elimination System Permit ((MPDES)(MT-0000477)) that is designed to prohibit Non-Piped Tank 350 Inflow. The proposed permit amendment will specify that Tank 350 shall receive only effluent that is piped from the API Separator outlet.

c. Upon EPA approval of the proposed permit modification relating to Tank 350, ExxonMobil shall within 60 days submit an application to the Applicable Co-Plaintiff to include the amendment to the Billings Refinery MPDES permit.

d. Within 90 days of the Entry Date, ExxonMobil shall submit to EPA a description of how wastewaters and/or other material that currently are Non-Piped Tank 350 Inflow will be managed at the Billings Refinery.

Q. **<u>INCORPORATION OF CONSENT DECREE REQUIREMENTS INTO FEDERALLY ENFORCEABLE PERMITS</u>.**

141. **<u>Emission Limits and Standards Effective on the Entry Date</u>**. By no later than 120 days after the Entry Date, ExxonMobil shall submit administratively complete applications to the applicable federal, state or local agency to incorporate the emission limits and standards, including NSPS applicability, required by this Consent Decree that are effective as of the Entry Date into federally-enforceable minor or major new source review permits or other permits that will ensure that the underlying emission limits and standards survive the termination of this Consent Decree in accordance with Paragraph 145. In light of the permitting program in the State of Louisiana, ExxonMobil shall submit to LDEQ's consolidated permitting program, under the time frame specified by the previous sentence, appropriate applications, amendments and/or supplements to ensure that the emission limits and standards that are effective as of the Entry Date under this Consent Decree shall survive the termination of this Consent Decree in accordance with Paragraph 145. Following submission of the complete permit applications (or, for the Baton Rouge Refinery, following submission of appropriate applications, amendments, or supplements), ExxonMobil shall cooperate with the applicable federal, state or local agency by promptly submitting to the applicable agency all available information that the applicable agency seeks following its receipt of the permit materials. Promptly upon issuance of such permits or in conjunction with such permitting, ExxonMobil shall file any applications necessary to incorporate the requirements of those permits into the Title V permit for the relevant Covered Refinery.

142. **<u>Future Emission Limits and Standards</u>**. As soon as practicable, but in no event later than ninety (90) days after the effective date or establishment of any emission limit or

standard under Section V that become effective after the Entry Date, ExxonMobil shall submit administratively complete applications to the applicable federal, state or local agency to incorporate that emission limit or standard into federally-enforceable minor or major new source review permits or other permits that will ensure that the underlying emission limit or standard survives the termination of this Consent Decree in accordance with Paragraph 145. In light of the permitting program in the State of Louisiana, ExxonMobil shall submit to LDEQ's consolidated permitting program, under the time frame specified by the previous sentence, appropriate applications, amendments and/or supplements to ensure that the emission limits and standards that become effective after the Entry Date shall survive the termination of this Consent Decree in accordance with Paragraph 145. Following submission of the complete permit applications (or, for the Baton Rouge Refinery, following submission of appropriate applications, amendments, or supplements), ExxonMobil shall cooperate with the applicable federal, state or local agency by promptly submitting to the applicable agency all available information that the applicable agency seeks following its receipt of the permit materials. Promptly upon issuance of such permits or in conjunction with such permitting, ExxonMobil shall file any applications necessary to incorporate the requirements of those permits into the Title V permit for the relevant Covered Refinery.

143. **Emission Limits and Standards.** The following Consent Decree requirements shall constitute the emission limits and standards that are required to be incorporated into permits under Paragraphs 141 and 142:

i. the interim emission limits and standards imposed by Subparagraphs 16.b, 29.a, 30.f, 30.g, and 68.b, for so long as each such interim emission limit or standard applies under this Consent Decree; and

ii. the requirements specified in Subparagraphs 145.a.(1) through 145.a.(9), that shall survive termination of the Consent Decree.

144. **<u>Mechanism for Title V Incorporation</u>.** The Parties agree that the incorporation of the requirements of this Consent Decree into Title V permits shall be in accordance with state Title V rules, including applicable administrative amendment provisions of such rules.

145. **<u>Obligations that Shall Survive Consent Decree Termination</u>**. The requirements imposed by the following provisions of this Consent Decree that shall survive termination of the Consent Decree under Section XVIII:

a. <u>Emission Limits and Standards</u>. The following Consent Decree requirements shall constitute emission limits and standards that shall survive termination of the Consent Decree by virtue of being incorporated into federally-enforceable permits:

(1) Subparagraphs 13.b, 14.b, 15.d, 16.c, 17.b, 18.b, 19.b, and Paragraph 21in Subsection V.B;

(2) Subparagraphs 23.b, 24.b, 25.b, 26.b, 27.b, 28.b, 29.b, and Paragraph 32 in Subsection V.C;

(3) Paragraphs 34 and 35 (if applicable as of the date of termination) in Subsection V.D;

(4) Paragraphs 39, 40 (if applicable as of the date of termination), and 42 in Subsection V.E;

(5) Paragraph 43 and 44 in Subsection V.F;

(6) Paragraphs 52, 53 and 54 in Subsection V.G;

(7) Subparagraphs 59.a and 59.b and Paragraph 60 in Subsection V.H;

(8) Paragraphs 63 and 64, Subparagraph 67.e, and Paragraph 69 in Subsection V.I; and

(9) Paragraphs 70, 71, and 73 in Subsection V.J.

b. Certain Other Requirements

(1) Subparagraph 65.a (as specified therein) in Subsection V.I;

(2) Paragraph 79 (as specified therein) and Subparagraph 91.a (as specified therein) in Subsection V.K;

(3) Paragraph 92 (as specified therein) in Subsection V.L;

(4) All of this Subsection V.Q; and

(5) All of Section VI.

c. Agreement Required for Changes to Surviving Requirements. In the event ExxonMobil should ever seek, after termination of this Consent Decree, to delete or modify an emission limit or standard surviving termination by virtue of Subparagraph 145.a, such emission limit or standard shall not be deleted or modified unless EPA and the Applicable Co-Plaintiff shall have first agreed in writing to the deletion or modification. In the event that ExxonMobil should ever seek to delete or modify any of the certain other requirements surviving termination pursuant to Subparagraph 145.b, such requirement shall not be deleted or modified unless EPA and the Applicable Co-Plaintiff shall have first agreed in writing to the deletion or modification.

146. **Obtaining Construction Permits.** ExxonMobil agrees to use its best efforts 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 affirmative relief and environmental projects set forth in Section V and in Section VIII. To the extent that ExxonMobil must submit permit applications for construction or installation to an applicable

state or local agency, ExxonMobil shall cooperate with the applicable state or local agency by promptly submitting to the applicable state or local agency all available information that the applicable state or local agency seeks following its receipt of the permit application. This Paragraph 146 is not intended to prevent ExxonMobil from applying to the applicable state or local agency for a pollution control project exemption.

VI. EMISSION CREDIT GENERATION

147. **Summary.** This Section addresses the use of emissions reductions that will result from the installation and operation of the controls required by this Consent Decree ("CD Emissions Reductions") for the purpose of emissions netting or emissions offsets. It allows ExxonMobil to use a fraction of the CD Emissions Reductions if: (1) the emissions units for which ExxonMobil seeks to use the CD Emissions Reductions are modified or constructed for purposes of compliance with Tier II gasoline or low sulfur diesel requirements; and (2) the emissions from those modified or newly-constructed units are at or below the levels outlined in Paragraph 149(2).

148. **General Prohibition.** ExxonMobil shall not generate or use any NOx, SO_2, PM, VOC, or CO emissions reductions, or apply for and obtain any emission reduction credits, that result from any projects conducted or controls required pursuant to this Consent Decree as netting reductions or emissions offsets in any PSD, major non-attainment and/or synthetic minor New Source Review ("NSR") permit or permit proceeding.

149. **Exception to General Prohibition.** Notwithstanding the general prohibition set forth in Paragraph 148, ExxonMobil may use 186 tons per year of NOx, 240 tons per year of SO_2, 38 tons per year of PM, 44 tons per year of CO, and 5 tons per year of H_2SO_4, from the CD Emissions Reductions as credits or offsets in any PSD, major non-attainment and/or synthetic

minor NSR permit or permit proceeding occurring after the Date of Lodging of the Consent Decree, provided that the new or modified emissions unit: (1) is being constructed or modified for purposes of compliance with Tier II gasoline or low sulfur diesel requirements; and (2) has a federally enforceable, non-Title V Permit with the following limits, as applicable:

i. For heaters and boilers, a limit of 0.020 lbs NOx per million BTU or less on a 3-hour rolling average basis;

ii. For heaters and boilers, a limit of 0.10 grains of hydrogen sulfide 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;

iii. For heaters and boilers, no Fuel Oil burning or solid fuel firing capability;

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

v. For FCCUs, a limit of 25 ppmvd SO_2 corrected to 0% O_2 or less on a 365-day rolling average basis; and

vi. For SRPs, NSPS Subpart J emission limits.

Utilization of the exception set forth above is subject to each of the following conditions:

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

ii. CD Emissions Reductions may be used only at the Covered Refinery that generated them;

iii. The CD Emissions Reductions provisions of this Consent Decree are for purposes of this Consent Decree only and neither ExxonMobil 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

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

150. **<u>Outside the Scope of the General Prohibition</u>.** Nothing in this Consent Decree is intended to prohibit ExxonMobil from seeking to:

i. utilize or generate netting reductions or emission offset credits from refinery units that are covered by this Consent Decree to the extent that the proposed netting reductions or emission offset credits represent the difference between the emissions limitations set forth in or established pursuant to this Consent Decree for these refinery units and the more stringent emissions limitations that ExxonMobil may elect to accept for these refinery units in a permitting process;

ii. utilize or generate netting reductions or emission offset credits for refinery units that are not subject to an emission limitation pursuant to this Consent Decree;

iii. utilize or generate netting reductions or emission offset credits for Combustion Units on which Qualifying Controls, as defined in Paragraph 46, have been installed, provided that such reductions are not included in ExxonMobil's demonstration of compliance with the requirements of Paragraphs 15.c, 47, or 50 of this Consent Decree;

iv. utilize emissions reductions from the installation of controls required by this Consent Decree in determining whether a project that includes both the installation of controls under this Consent Decree and other construction that occurs at the same time and is permitted as a single project triggers major New Source Review requirements;

v. utilize CD Emission Reductions for a Covered 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, RECLAIM and the Houston/Galveston Area NOx SIP) that apply to the particular Covered Refinery; provided, however, that ExxonMobil shall not be allowed to trade or sell any CD Emissions Reductions; or

vi. utilize any emission reduction credits recognized under two permits previously issued to ExxonMobil, namely: (1) the Baton Rouge Refining Clean Air Commitment PSD-LA-667(M-1) and Catalytic Cracking Permit Number 2385-V1; and (2) the IEPA Construction Permit for the Joliet Coker Blowdown Recovery Project (Application Number 03060091).

VII. MODIFICATIONS TO IMPLEMENTATION SCHEDULES

151. **Modifications Relating to Securing Permits or Approvals (in States Where Permits are Characterized as "Approvals").**

a. Timely Submitting Complete Permit Applications and Exercising Best Efforts. For any work under Sections V or VIII of this Consent Decree that requires a federal, state and/or local permit or approval (including but not limited to air or wastewater permits or approvals), ExxonMobil shall be responsible for submitting in a timely fashion applications for federal, state and local permits and approvals for work and activities required so that permit or approval decisions can be made in a timely fashion. ExxonMobil shall use its best efforts to: (i) submit permit applications (i.e., applications for permits to construct, operate, or their equivalent) that comply with all applicable requirements; and (ii) secure approval of permits after filing the applications, including timely supplying additional information, if requested.

b. Notification. If it appears that the failure of a governmental entity to act upon a timely-submitted, complete permit application may delay ExxonMobil's performance of work according to an applicable implementation schedule, ExxonMobil will notify the EPA and the Applicable Co-Plaintiff of any such delays as soon as ExxonMobil reasonably concludes that the delay could affect its ability to comply with the implementation schedule set forth in this Consent Decree. ExxonMobil shall propose for approval by EPA a modification to the applicable schedule of implementation setting out the time necessary to comply after the permit or approval has been received by ExxonMobil. EPA, after an opportunity for consultation with the Applicable Co-Plaintiff, shall not unreasonably withhold its consent to requests for modifications of schedules of implementation if the requirements of this Paragraph 151 are met.

c. Stipulated Penalties Inapplicable. Stipulated penalties shall not accrue nor be due and owing during any period between an originally-scheduled implementation date and an approved modification to such date; provided, however, that if EPA does not approve a modification to a date or dates then: (i) EPA and the Applicable Co-Plaintiff will retain the right to seek stipulated penalties; and (ii) ExxonMobil will retain the right to dispute any demand for stipulated penalties, pursuant to Paragraph 215.

d. Force Majeure Inapplicable. The failure of a governmental entity to act upon a timely-submitted permit or approval application shall not constitute a force majeure event triggering the requirements of Section XIV; instead, this Paragraph 151 shall apply.

152. **Modifications Relating to Securing EPA Approval under this Consent Decree.**

a. For requirements of this Decree where ExxonMobil is prohibited from commencing an action prior to receiving EPA approval, ExxonMobil will use its best efforts to submit materials that comply with all applicable requirements of this Consent Decree and to ensure EPA's timely response to the applicable submission. If it appears that the failure by EPA to timely provide an approval that is a condition precedent to subsequent action(s) will delay ExxonMobil's performance of subsequent action(s), ExxonMobil and EPA will modify all relevant deadlines as appropriate in light of the delay. If EPA fails to timely act on a modification(s) required by this Subparagraph, stipulated penalties will not accrue for the period up to and including the earlier of: (i) the modified date(s) that EPA eventually determines; or (ii) the modified date(s) that this Court establishes if ExxonMobil pursues dispute resolution under Section XV.

b. For requirements of this Consent Decree that are subject to EPA approval but for which ExxonMobil's subsequent actions are not expressly conditioned upon receipt of EPA approval, ExxonMobil will commence and continue with such subsequent actions even without receipt of EPA approval. If, during the course of such continuing ExxonMobil actions, EPA disapproves in whole or in part of the manner in which ExxonMobil has proceeded, extensions of all relevant deadlines may result by agreement of the parties. Stipulated penalties will not accrue nor be due and owing during any period between a scheduled implementation date and an approved modification to such date; provided, however, that if EPA does not approve a modification to a date or dates then: (i) EPA and the Applicable Co-Plaintiff will retain the right to seek stipulated penalties; and (ii) ExxonMobil will retain the right to dispute any demand for stipulated penalties, pursuant to Paragraph 215.

c. Force Majeure Inapplicable. The failure of EPA to provide a required approval in a timely manner will not constitute a force majeure event triggering the requirements of Section XIV; instead, this Paragraph 152 shall apply.

153. **Modifications Relating to Commercial Unavailability of Control Equipment and/or Additives**.

a. ExxonMobil's General Obligation. ExxonMobil shall be solely responsible for compliance with any deadline or the performance of any work described in Sections V and VIII of this Consent Decree that requires the acquisition and installation of control equipment, including SO_2 Reducing Catalyst Additive or NOx Additives.

b. Notification. If it appears that the commercial unavailability of any control equipment may delay ExxonMobil's performance of work according to an applicable implementation schedule, ExxonMobil shall notify EPA and the Applicable Co-Plaintiff of any such delays as soon as practicable after ExxonMobil reasonably concludes that the delay could affect its ability to comply with the implementation schedule set forth in this Consent Decree. ExxonMobil shall then contact a reasonable number of vendors of such equipment or additive and obtain (or request) a written representation (or equivalent communication to EPA) from the vendor that the equipment or additive is commercially unavailable.

c. Additional Notice Requirements and Requirements Relating to Contacting Vendors. ExxonMobil shall propose for approval by EPA a modification to the applicable schedule of implementation, refer to this Paragraph 153 of this Consent Decree, identify the milestone date it contends it will not be able to meet, provide EPA and the Applicable Co-Plaintiff with written correspondence to the vendor identifying efforts made to secure the control equipment or catalyst additive, and describe the specific efforts ExxonMobil has taken and will continue to take to find such equipment or additive. ExxonMobil may propose a modified schedule or modification of other requirements of this Consent Decree to address such commercial unavailability.

d. Dispute Resolution. Section XV (Retention of Jurisdiction/Dispute Resolution) shall govern the resolution of any claim of commercial unavailability. EPA, after an opportunity for consultation with the Applicable Co-Plaintiff, shall not unreasonably withhold its consent to requests for modifications of schedules of implementation if the requirements of this Paragraph are met.

e. Stipulated Penalties Inapplicable. Stipulated penalties shall not accrue nor be due and owing during any period between an originally-scheduled implementation date and an approved modification to such date; provided, however, that if EPA does not approve a modification to a date or dates then: (i) EPA and the Applicable Co-Plaintiff will retain the right to seek stipulated penalties; and (ii) ExxonMobil will retain the right to dispute any demand for stipulated penalties, pursuant to Paragraph 215.

f. Force Majeure Inapplicable. The failure of ExxonMobil to secure control equipment or additives will not constitute a force majeure event triggering the requirements of Section XIV; instead, this Paragraph shall apply.

154. **<u>Procedures for Modifying Implementation Schedules under this Section VII</u>**. Any modifications to implementation schedules under this Section VII shall be made in accordance with Paragraph 269.

VIII. ENVIRONMENTALLY BENEFICIAL PROJECTS

155. In accordance with the requirements and schedule set forth in this Section VIII, ExxonMobil shall pay $6,700,000 to implement Supplemental Environmental Projects ("SEPs") and Beneficial Environmental Projects ("BEPs"), as described below.

156. <u>Supplemental Environmental Projects</u>.

a. <u>Performance of SEPs</u>. ExxonMobil may carry out its responsibilities for the SEPs required by this Paragraph directly or through contractors or other third-parties selected by ExxonMobil.

b. <u>The Smart LDAR Project</u>. By no later than December 31, 2007, ExxonMobil shall perform a SEP designed to demonstrate and evaluate the use of Smart LDAR imaging equipment in identifying and quantifying emissions from leaking components and other sources of fugitive VOC emissions at the Baytown Refinery, at a cost of no less than $250,000 (the "Smart LDAR Project").

(1) Within 90 days of the Entry Date, ExxonMobil shall submit a plan for the Smart LDAR Project, which shall be subject to EPA review and approval. The plan shall include a proposal for: (i) comparative monitoring, to compare the results achieved with at least one Smart LDAR imaging camera against the results achieved through traditional Method 21 monitoring; and/or (ii) "bag" testing, to quantify the mass of VOC emissions from one or more leaking components monitored with a Smart LDAR imaging camera. The plan shall also include a description of the project's overall

objective(s), the procedures to be followed, a project budget (detailing expected equipment costs, laboratory costs, and contractor costs), and a schedule for performing and completing the project.

(2) Upon receipt of EPA approval, ExxonMobil shall implement the plan for the Smart LDAR Project according to the schedule provided in the approved plan.

c. Diesel Emissions Reduction Projects. By no later than December 31, 2009, ExxonMobil shall spend no less than $1,300,000 in performing diesel emissions reduction SEPs in accordance with the criteria, terms, and procedures specified in Appendix Q of this Consent Decree.

d. Midewin National Tallgrass Prairie Restoration Project. By no later than December 31, 2009, ExxonMobil shall perform one or more prairie habitat restoration projects at the Midewin National Tallgrass Prairie that will require in-kind contributions and expenditures of $1,050,000 or more, as described by this Subparagraph 156.d.

(1) By no later than December 31, 2007, ExxonMobil shall take all actions required to donate the parcel of property identified on the drawing attached as Appendix R (comprising approximately 39 acres, and referred to in this Subparagraph as the "Property") to the United States, so that the parcel can be added to the Midewin National Tallgrass Prairie managed by the U.S. Department of Agriculture, Forest Service. ExxonMobil may condition the donation upon the United States' acceptance of the Property subject to the following deed restrictions:

> "The land shall only be used and managed to conserve and enhance the native populations and habitats of fish, wildlife, and plants as part of the Midewin National Tallgrass Prairie, and to provide opportunities for

> associated research, in accordance with the Illinois Land Conservation Act of 1995 (Public Law 104–106, Title XXIX, section 2901, *et seq.*) and shall not be used for residential or commercial development."

(2) The Property shall be conveyed by ExxonMobil by general warranty deed to the "United States of America and its assigns," and title thereto shall be acceptable to the Secretary of Agriculture in accordance with title standards of the Attorney General of the United States.

(3) Within 120 days prior to the proposed date of closing, ExxonMobil will provide the Forest Service with all available environmental studies and remediation reports relating to the Property; all available title, survey, and other land records relating to the Property; and any other available documentation pertaining to the title, upkeep, maintenance or similar records relating to the Property.

(4) The United States, through the Forest Service, has the option to either accept or decline the conveyance of the Property for reasons of its environmental condition, title, or other reason in the discretion of the Forest Service.

(5) If the United States accepts the property donation and the associated deed restrictions, ExxonMobil will be credited with providing an $800,000 in-kind contribution (hereinafter the "In-Kind Contribution Amount"). If the United States notifies ExxonMobil that it will not accept the property donation and the associated deed restrictions, then the In-Kind Contribution Amount under this Subparagraph 156.d.(5) shall be $0.

(6) ExxonMobil shall enter into a separate written agreement with the U.S. Department of Agriculture, Forest Service or its contractors or assignees, pursuant to 16 U.S.C. § 579(c) or other available authorities, for performance of prairie habitat

restoration, protection, preservation, or acquisition work at the Midewin National Tallgrass Prairie by no later than December 31, 2009. ExxonMobil shall spend at least $250,000 for performance of that prairie habitat restoration, protection, preservation and/or acquisition work, as determined by the following formula:

	$1,050,000
–	In-Kind Contribution Amount Under Subparagraph 156.d.(5)
=	Required Expenditure Under this Subparagraph 156.d.(6)

If any portion of the Required Expenditure under this Subparagraph 156.d.(6) is to be used for acquisition of additional property, then the acquired property shall be managed to conserve and enhance the native populations and habitats of fish, wildlife, and plants as part of the Midewin National Tallgrass Prairie, and to provide opportunities for associated research, in accordance with the Illinois Land Conservation Act of 1995 (Public Law 104–106, Title XXIX, section 2901, *et seq.*) and shall not be used for residential or commercial development.

e. Will County Emergency Management Agency Equipment Purchase Project. By no later than December 31, 2007, ExxonMobil will spend at least $100,000 to purchase and/or upgrade emergency response equipment (such as mobile computer data terminals, hazardous materials vehicles, radio equipment, and protective suits) for the Will County Emergency Management Agency. The Will County Emergency Management Agency serves as the Local Emergency Planning Committee for the area near ExxonMobil's Joliet Refinery.

f. Billings Refinery Pressure Relief Valve Control Project. By no later than the dates set forth below, ExxonMobil shall perform a SEP designed to control hydrogen sulfide emissions from episodic releases from atmospheric pressure release valves ("PRVs") at the

Billings Refinery, at a cost of no less than $1,500,000 (the "PRV Project"). ExxonMobil shall develop and satisfactorily complete the PRV Project as described by the following Subparagraphs.

(1) By no later than 365 days after the Entry Date, ExxonMobil shall complete an engineering evaluation for the PRV Project. The engineering evaluation shall assess the relative costs and benefits of various PRV control options at the Billings Refinery, and shall: (i) identify PRVs in hydrogen sulfide service, (ii) estimate the amount of hydrogen sulfide that might be emitted during a release incident at each such PRV, (iii) assess the recent history of releases (if any) from the particular PRV, and (iv) estimate the cost of routing each such PRV or particular sets of PRVs to the Billings Refinery's amine treatment systems, flare gas recovery systems, and/or flares.

(2) By no later than 365 days after the Entry Date, ExxonMobil shall prepare a proposed plan for spending the $1,500,000 PRV Project budget (the "PRV Project Plan"), based on the results of the engineering evaluation required by Subparagraph 156.f.(1), and ExxonMobil shall submit the PRV Project Plan for review and approval by EPA and MDEQ. The PRV Project Plan shall: (i) summarize the results of ExxonMobil's engineering evaluation, and (ii) propose a specific plan and schedule for spending the $1,500,000 PRV Project budget on cost effective measures to control hydrogen sulfide emissions from episodic releases from PRVs at the Billings Refinery. The schedule for implementing such measures shall not extend beyond December 31, 2009, unless EPA and MDEQ agree to a request from ExxonMobil for an extension of time pursuant to Paragraph 269 (Consent Decree Modifications).

(3) ExxonMobil shall implement the PRV Project Plan as approved by EPA and MDEQ, and shall operate and maintain the hydrogen sulfide emission controls installed as part of the PRV Project .

g. Joliet Refinery Heater Firing Reduction Project.

(1) By no later than December 31, 2009, ExxonMobil shall install air control technology (including burner management and analyzer technology) on 1-B-3, 13-B-4, and 2-B-3/4/5/6 heaters at the Joliet Refinery to reduce annually at least 2000 tons of carbon dioxide ("CO_2") emissions from those heaters. Any associated NOx emission reductions from 1-B-3, 13-B-4, and 2-B-3/4/5/6 heaters shall not be used to achieve the NOx emission reductions for heaters and boilers required by Subsection V.G of this Decree, and all CO_2 and NOx emission reductions resulting from this SEP shall be permanently retired (i.e., not used as emission reduction credits). ExxonMobil shall spend no less than $800,000 on this SEP.

(2) ExxonMobil may request that EPA and IEPA approve the substitution of another heater or boiler located at the Joliet Refinery for heaters 1-B-3, 13-B-4, and 2-B-3/4/5/6. EPA and IEPA will approve ExxonMobil's request if ExxonMobil demonstrates that its actions will result in a reduction in CO_2 emissions of at least 2000 tons. If EPA and IEPA approve a substitution, ExxonMobil shall not use emission reductions from the substitute heater or boiler to comply with Subsection V.G of this Decree.

157. ExxonMobil shall include in each Semi-Annual Report required by Section IX, a progress report for SEPs specified by Paragraph 156. In addition, the first Semi-Annual Report that is submitted after December 31, 2009 (or after any extended deadline for the performance of

the SEPs) shall contain the following information with respect to the SEPs specified by Paragraph 156:

i. A detailed description of each such SEP as implemented;

ii. A brief description of any significant operating problems encountered, including any that had an impact on the environment, and the solutions for each problem;

iii. A summary of the costs ExxonMobil incurred in performing the SEPs specified by Paragraph 156;

iv. Certification that the project has been fully implemented pursuant to the provisions of this Consent Decree; and

v. A description of the environmental and public health benefits resulting from implementation of the project (including quantification of the benefits and pollutant reductions, if feasible).

158. If ExxonMobil completes a SEP described in Paragraph 156, but does not expend all of the project-specific amount specified in Paragraph 156, then ExxonMobil shall, with respect to the difference between the project-specific amount and the amount actually expended, either:

i. pay the difference as a stipulated penalty under Paragraph 214, if a written demand for payment is made at any time by EPA;

ii. use the difference to fund an increase in the scope and/or budget of one or more of the other SEPs specified by Paragraph 156, with the advance written approval of EPA and the Applicable Co-Plaintiff(s) as set forth in a non-material modification to the Consent Decree under Paragraph 269; or

iii. use the difference to fund another appropriate SEP, with the advance written approval of EPA and the Applicable Co-Plaintiff(s) as set forth in a material modification to the Consent Decree under Paragraph 269.

159. <u>State of Louisiana Beneficial Environmental Projects</u>. As a term and condition of the settlement between ExxonMobil and LDEQ that is reflected in this Consent Decree, ExxonMobil shall pay $1,700,000 to the Louisiana Wildlife and Fisheries Foundation within

thirty (30) days of the Entry Date in order to fund performance of one or more BEPs under La. Admin. Code tit. 33, I Chapter 25. In the first Semi-Annual Report that is required by Section IX, ExxonMobil shall confirm whether that payment was made as required by this Paragraph 159. LDEQ has agreed that the Louisiana Wildlife and Fisheries Foundation will perform the BEPs that are to be funded with that payment, as described in Appendix O to this Consent Decree.

160. Public Statements. ExxonMobil agrees that in any public statements it makes or causes to be made regarding the SEPs or BEPs, ExxonMobil must clearly indicate that these projects are being undertaken as part of the settlement of an enforcement action for alleged violations of the Clean Air Act and corollary state statutes.

IX. RECORDKEEPING AND REPORTING

161. ExxonMobil shall submit Semi-Annual Reports to EPA and the Applicable Co-Plaintiff that contain the following information:

i. a progress report on the implementation of the requirements of Section V (Affirmative Relief) at the Covered Refineries;

ii. a summary of the emissions data, including a separate identification of any exceedance(s) of Consent Decree emission limitations or standards for the Covered Refineries set forth in or established pursuant to Section V of this Consent Decree, for the six (6) month period covered by the report;

iii. a description of any problems anticipated with respect to meeting the requirements of Section V of this Consent Decree at the Covered Refineries;

iv. a progress report on the implementation of the requirements of Section VIII (Environmentally Beneficial Projects);

v. any such additional matters as ExxonMobil believes should be brought to the attention of EPA and the Applicable Co-Plaintiff; and

vi. additional items required by another Paragraph of this Consent Decree to be submitted with a Semi-Annual Report.

Semi-Annual Reports shall be submitted by August 31 (covering the period from January 1 to June 30) and February 28 (covering the period from July 1 to December 31), with the first such Report due on the first reporting date after the Entry Date. The Semi-Annual Report shall be certified by: (i) the person responsible for environmental management and compliance for each of the Covered Refineries; or (ii) a person responsible for overseeing implementation of this Decree for ExxonMobil, as follows:

> I certify under penalty of law that this information [related to _______ refiner(y)(ies)] was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or 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.

X. CIVIL PENALTY

162. **Civil Penalty.**

a. Within thirty (30) days of the Entry Date, ExxonMobil shall pay a civil penalty of $7,700,000 as follows: (i) $6,000,000 to the United States; (ii) $650,000 to the State of Illinois; (iii) $900,000 to the State of Louisiana; and (iv) $150,000 to the State of Montana. Of the $6,000,000 to be paid to the United States, $500,000 of that amount will be a civil penalty paid to the EPA Hazardous Substances Superfund.

b. Payment of monies to the United States shall be made by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing DOJ Case Number 90-5-2-1-07030 and the civil action case name and case number of this action in the Northern District of Illinois. The costs of such EFT shall be the responsibility of ExxonMobil. Payment shall be made in accordance with instructions provided to ExxonMobil by the Financial Litigation Unit of the U.S. Attorney's Office for the Northern

District of Illinois. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. ExxonMobil shall provide notice of payment, referencing DOJ Case Number 90-5-2-1-07030 and the civil action case name and case number to the Department of Justice and to EPA, as provided in Paragraph 266 (Notice).

c. Payment of the civil penalty owed to the State of Illinois under this Paragraph shall be made as follows:

(1) $100,000 shall be paid by certified or corporate check payable to the Illinois Environmental Protection Agency, or by an electronic funds transfer, for deposit into the Illinois Environmental Protection Trust Fund, and shall be sent by first-class mail (unless submitted by electronic funds transfer) and delivered to the following address:

Illinois Environmental Protection Agency
Fiscal Services Section
1021 North Grand Avenue East
P.O. Box 19276
Springfield, IL 62794-9276

The name and number of the case and ExxonMobil Oil Corporation's Federal Employer Identification Number (FEIN) 13-5401570 shall appear on the check. A copy of the certified or corporate check or record of electronic funds transfer and any transmittal letter shall be sent to:

Environmental Bureau
Office of the Illinois Attorney General
188 West Randolph Street, 20th Floor
Chicago, IL 60601

and

Maureen Wozniak
Assistant Counsel
Illinois EPA
1021 North Grand Avenue East
Springfield, IL 62794-9276

(2) The Illinois Environmental Protection Agency directs that $275,000 of the civil penalty shall be paid by certified or corporate check payable to the Illinois Environmental Protection Agency, designated to the Special State Projects Trust Fund, and submitted to:

Illinois Environmental Protection Agency
Fiscal Services Section
1021 North Grand Avenue East
P.O. Box 19276
Springfield, IL 62794-9276

The name and number of the case and ExxonMobil Oil Corporation's Federal Employer Identification Number (FEIN) 13-5401570 shall appear on the check. A copy of the certified or corporate check and any transmittal letter shall be sent to:

Environmental Bureau
Office of the Illinois Attorney General
188 West Randolph Street, 20th Floor
Chicago, IL 60601

and

Maureen Wozniak
Assistant Counsel
Illinois EPA
1021 North Grand Avenue East
Springfield, IL 62794-9276

(3) $275,000 shall be paid by certified or corporate check payable to the "Attorney General State Projects and Court Ordered Distribution Fund" to be used at the discretion of the Illinois Attorney General's Office for the advancement of

environmental protection, enhancement and education activities in Illinois. The check shall be delivered to the following address:

Environmental Bureau
Office of the Illinois Attorney General
188 West Randolph Street, 20th Floor
Chicago, IL 60601

The name and number of the case and ExxonMobil Oil Corporation's Federal Employer Identification Number (FEIN) 13-5401570 shall appear on the check.

d. Payment of the civil penalty owed to the State of Louisiana under this Paragraph shall be made by certified check made payable to the Louisiana Department of Environmental Quality and sent to Darryl Serio, Fiscal Director, Office of Management and Finance, LDEQ, P.O. Box 4303, Baton Rouge, LA 70821-4303.

e. Payment of the civil penalty owed to the State of Montana under this Paragraph shall be made by certified or corporate check made payable to the State of Montana and sent to the following address:

John L. Arrigo
Administrator, Enforcement Division
Montana Department of Environmental Quality
P.O. Box 200901
Helena, MT 59620-0901

163. The amount set forth in Paragraph 155 for SEPs and BEPs and the civil penalty set forth in Subparagraph 162.a together constitute the sole penalty imposed for the violations alleged hereunder within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and, therefore, ExxonMobil shall not treat these penalty payments as tax deductible for purposes of net income taxes imposed under federal, state, or local law.

164. Upon the Entry Date, the Consent Decree shall constitute an enforceable judgment for purposes of post-judgment collection in accordance with Federal Rule of Civil Procedure 69, the Federal Debt Collection Procedure Act, 28 U.S.C. §§ 3001-3308, and other applicable federal authority.

XI. STIPULATED PENALTIES

165. **Generally.**

a. ExxonMobil shall pay stipulated penalties to the United States and to the Applicable Co-Plaintiff for each failure by ExxonMobil to comply with the terms of this Consent Decree as provided herein. Stipulated penalties shall be calculated in the amounts specified in this Section XI. Stipulated penalties for failure to comply with the concentration-based, rolling average emission limits referenced in Section V shall not start to accrue until there is noncompliance for 5% or more of the applicable unit's operating time during any calendar quarter.

b. For those provisions where a stipulated penalty of either a fixed amount or 1.2 times the economic benefit of non-compliance is available, the decision of which alternative to seek shall rest exclusively within the discretion of the EPA and the Applicable Co-Plaintiff. For the purposes of this Section XI, the term "economic benefit of non-compliance" means the economic benefit accrued from delaying a capital investment, delaying a one-time expenditure, and avoiding recurring costs (such as operation and maintenance costs) over the period of non-compliance. The overall "economic benefit of non-compliance" will be calculated based on the total number of days of non-compliance, and will be multiplied by 1.2 to compute the total stipulated penalty amount under a particular provision of this Section XI. That total stipulated penalty amount will be assessed for the full period of non-compliance, and will not be assessed "per day." In no event shall any stipulated penalty assessed against ExxonMobil exceed $32,500 (or any inflation-adjusted increase in that maximum penalty amount set pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, as amended by the Debt Collection Improvement Act of 1996) per day for any individual violation of this Consent Decree.

c. Where a single event triggers more than one stipulated penalties provision in this Consent Decree, only the provision providing for the higher stipulated penalty shall apply. In cases where a violation of this Consent Decree is also a violation that provides a basis for potential recovery of civil penalties under of the Clean Air Act, another federal environmental law, and/or an applicable state or local environmental law, the United States and the Applicable Co-Plaintiff will each elect between seeking stipulated penalties under this Consent Decree and commencing a new action for civil penalties under such laws. Notwithstanding the foregoing, the United States and the Applicable Co-Plaintiffs reserve the right to pursue any other non-monetary remedies to which they are legally entitled, including but not limited to injunctive relief for violations of the Consent Decree.

d. For the purposes of this Section XI, terms such as "per refinery," "per unit," "per valve," "per drain" and the like shall mean only each refinery, each unit, each valve, or each drain that is in non-compliance with a specific Consent Decree requirement.

A. Requirements for NO_X Emission Reductions from the FCCUs.

166. For failure to meet any FCCU Interim NOx Limit or Final NOx Limit set forth in or established pursuant to Subparagraphs 13.b, 14.b, 16.b, 16.c, 17.b, 18.b, or 19.b, per FCCU: $750 for each calendar day in a calendar quarter in which the short-term rolling average exceeds the applicable limit; and $2,500 for each calendar day in a calendar quarter on which the specified 365-day rolling average exceeds the applicable limit.

167. For failure to comply with any of the Baton Rouge and Beaumont NOx Minimization Studies requirements specified by Paragraph 15, including submission of required reports, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$1,000
31st through 60th day after deadline	$1,500
Beyond 60th day after deadline	$2,000, or an amount equal to 1.2 times the economic benefit of non-compliance whichever is greater

168. For failure to specify Interim NOx Limits or Final NOx Limits for Baytown FCCU 2 and/or Baytown FCCU 3, as required by Subparagraph 16.b or 16.c, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$1,000
31st through 60th day after deadline	$1,500
Beyond 60th day after deadline	$2,000, or an amount equal to 1.2 times the economic benefit of non-compliance whichever is greater

169. For failure to install, certify, calibrate, maintain, and/or operate a CEMS, as required by Paragraph 21, per day, per CEMS:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$500
31st through 60th day after deadline	$1,000
Beyond 60th day after deadline	$2,000 or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

B. Requirements for SO_2 Emission Reductions from the FCCUs.

170. For each failure to meet any FCCU Final SO_2 Limit set forth in or established pursuant to Subparagraphs 23.b, 24.b, 25.b, 26.b, 27.b, 28.b, or 29.b, per FCCU: $750 for each calendar day in a calendar quarter on which the specified 7-day rolling average exceeds the applicable limit; $2,500 for each calendar day in a calendar quarter on which the specified 365-day rolling average exceeds the applicable limit.

171. For failure to comply with any of the Particular Requirements for the Billings FCCU: Conversion to Full Burn Operation and Two-Step SO_2 Reducing Catalyst Additive Program, as set forth in Paragraph 30, including submission of required reports, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$1,000
31st through 60th day after deadline	$1,500
Beyond 60th day after deadline	$2,000, or an amount equal to 1.2 times the economic benefit of non-compliance whichever is greater

172. For failure to install, certify, calibrate, maintain, and/or operate a CEMS, as required by Paragraph 32, per day, per CEMS:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$500
31st through 60th day after deadline	$1,000
Beyond 60th day after deadline	$2,000 or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

C. **<u>Requirements for PM Emissions Reductions from the FCCUs</u>.**

173. For each failure to meet any FCCU Final PM Limit that ExxonMobil accepts pursuant to Paragraph 35 (if applicable), per day, per FCCU: $500 for the first day of non-compliance in which the specified short-term rolling average exceeds the applicable limit, and $1,500 for each day thereafter until ExxonMobil demonstrates compliance with the applicable limit.

174. For failure to conduct PM testing, as required by Paragraph 37, per day, per FCCU:

Period of 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

D. **<u>Requirements for CO Emissions Reductions from the FCCUs</u>**.

175. For each failure to meet any FCCU Final CO Limit that ExxonMobil accepts pursuant to Paragraph 40 (if applicable), per day, per FCCU: $750 for each calendar day in a calendar quarter in which the short-term rolling average exceeds the applicable limit; and $2,500 for each calendar day in a calendar quarter on which the specified 365-day rolling average exceeds the applicable limit.

176. For failure to install, certify, calibrate, maintain, and/or operate a CEMS, as required by Paragraph 42, per day, per CEMS:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$500
31st through 60th day after deadline	$1,000
Beyond 60th day after deadline	$2,000, or, an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

E. Requirements Related to NSPS Applicability to FCCU Regenerators.

177. For failure to comply with NSPS Subparts A and J limits applicable to a particular FCCU's catalyst regenerator, as required by Paragraphs 34, 39, and 43, per pollutant, per unit, per day in a calendar quarter:

Period of Non-Compliance	Penalty per day
1st through 30th day	$1,000
31st through 60th day	$2,000
Over 60 days	$3,000 or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

178. For failure to comply with any of the Particular Requirements Applicable to the Baton Rouge FCCUs specified by Subparagraphs 44.b and 44.c: $3,000 per day of non-compliance, or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

F. Requirements for NOx Emission Reductions from Combustion Units.

179. For failure to install selected Qualifying Controls on Combustion Units or to reduce NOx emissions from Combustion Units as required by Paragraphs 47, 50, or 51, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$2,500
31st through 60th day after deadline	$6,000
Beyond 60th day after deadline	$10,000, or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

180. For failure to comply with the applicable monitoring requirements as set forth in Paragraphs 53 and 54, per Combustion Unit, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$500
31st through 60th day after deadline	$1,000
Beyond 60th day after deadline	$2,000, or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

181. For failure to submit the written deliverables required by Paragraph 49, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$200
31st through 60th day after deadline	$500
Beyond 60th day after deadline	$1,000

G. Requirements for SO_2 Emission Reductions from Heaters, Boilers, and Other Fuel Gas Combustion Devices.

182. For burning in any heater or boiler (including but not limited to those listed in Appendix C) or in any Other Fuel Gas Combustion Device (listed in Appendix D) any refinery fuel gas in violation of the applicable requirements of NSPS Subparts A and J after the Entry Date or, if the device is listed in Appendix C or D, after the date set forth in Appendix C or D on which the respective device becomes an "affected facility" subject to NSPS Subparts A and J, as set forth in Subsection V.H., per device, per day in a calendar quarter:

Period of Non-Compliance	Penalty per day
1st through 30th day	$2,500
Beyond 31st day	$5,000 or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

183. For burning Fuel Oil in a manner inconsistent with the requirements of Paragraph 60, per device, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day	$1,750
Beyond 31st day	$5,000

H. **Requirements for Sulfur Recovery Plants**.

184. For failure to comply with the NSPS Subparts A and J emission limits at a Sulfur Recovery Plant listed in Paragraph 63, as specified in Subparagraph 64.a, per day, per SRP:

Period of Non-Compliance	Penalty per day
1st through 30th day	$1,000
31st through 60th day	$2,000
Over 60 days	$3,000 or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

185. For failure to comply with NSPS Subparts A and J monitoring requirements at a Sulfur Recovery Plant listed in Paragraph 63, as specified in Subparagraph 64.b, per day, per SRP:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$500
Beyond 31st day after deadline	$1,500
Beyond 60th day after deadline	$2,000

186. For failure to develop a Preventive Maintenance and Operation Plan as specified in Paragraph 65, per day, per Plan:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$500
Beyond 31st day after deadline	$1,500
Beyond 60th day after deadline	$2,000

187. For failure to complete the Baton Rouge and Joliet optimization studies and reports as required by Paragraph 66, per Refinery, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$500
Beyond 31st day after deadline	$1,500
Beyond 60th day after deadline	$2,000

188. For failure to comply with any of the Particular Requirements for Baton Rouge FCCUs specified by Subparagraphs 67.a - 67.d: $3,000 per day of non-compliance, or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

189. For failure to comply with an Interim Performance Standard applicable to the Joliet East Claus Train or the Joliet West Claus Train under Subparagraph 68.b, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day	$1,000
31st through 60th day	$2,000
Over 60 days	$3,000 or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

190. For failure to manage all sulfur pit emissions in accordance with the requirements of Paragraph 69, per day, per Refinery:

Period of Non-Compliance	Penalty per day
1st through 30th day	$1,000
31st through 60th day	$1,750
Beyond 60th day	$4,000 or an amount equal to 1.2 times the economic benefit of non-compliance whichever is greater.

I. Requirements for Flaring Devices.

191. For failure to comply with the requirement in Paragraphs 71 and 73 that an NSPS Flaring Device comply with the compliance method specified in Appendix G, by the date specified in Appendix G, per day, per device:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$500
Beyond 31st day after deadline	$1,500
Beyond 60th day after deadline	$2,000

Provided, however, that if stipulated penalties could be assessed under both Paragraphs 191 and 192, the provisions of Paragraph 192 shall control.

J. <u>Requirements for Control of AG Flaring Incidents and Tail Gas Incidents</u>.

192. For AG Flaring Incidents and/or Tail Gas Incidents for which ExxonMobil is liable under Subsection V.K:

Tons Emitted in Flaring Incident or Tail Gas Incident	Length of Time from Commencement of Flaring within the Flaring Incident to Termination of Flaring within the Flaring Incident is 3 hours or less; Length of Time of the Tail Gas Incident is 3 hours or less	Length of Time from Commencement of Flaring within the Flaring Incident to Termination of Flaring within the Flaring Incident is greater than 3 hours but less than or equal to 24 hours; Length of Time of the Tail Gas Incident is greater than 3 hours but less than or equal to 24 hours	Length of Time of Flaring within the Flaring Incident is greater than 24 hours; Length of Time of the Tail Gas Incident is greater than 24 hours
5 Tons or less	$500 per Ton	$750 per Ton	$1,000 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, $27,500 in any one calendar day
Greater than 15 Tons	$1,800 per Ton, up to, but not exceeding, $27,500 in any one calendar day	$2,300 per Ton, up to, but not exceeding, $27,500 in any one calendar day	$27,500 per calendar day for each calendar day over which the Flaring Incident lasts

For purposes of calculating stipulated penalties pursuant to this Paragraph, only one cell within the matrix shall apply. Thus, for example, for an AG Flaring Incident in which the flaring starts at 1:00 p.m. and ends at 3:00 p.m., and for which 14.5 tons of sulfur dioxide 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)]. For purposes of determining which column in the table set forth in this Paragraph applies under circumstances in which flaring occurs intermittently during an

AG Flaring Incident, the flaring shall be deemed to commence at the time that the flaring that triggers the initiation of an AG Flaring Incident commences, and shall be deemed to terminate at the time of the termination of the last episode of flaring within the AG Flaring Incident. Thus, for example, for flaring within an AG 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) for which no further Flaring occurs within the Flaring Incident, the flaring within the AG Flaring Incident shall be deemed to last 12.5 hours -- not 1.5 hours -- and the column for flaring of "greater than 3 hours but less than or equal to 24 hours" shall apply.

193. For failure to timely submit any report required by Subsection V.K, or for submitting any report that does not substantially conform to its requirements:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

194. For those corrective action(s) which ExxonMobil: (i) agrees to undertake following receipt of an objection by EPA pursuant to Paragraph 81; or (ii) is required to undertake following dispute resolution, then, from the date of EPA's receipt of ExxonMobil's report under Paragraph 80 of this Consent Decree until the date that either: (i) a final agreement is reached between EPA and ExxonMobil regarding the corrective action; or (ii) a court order regarding the corrective action is entered, ExxonMobil shall be liable for stipulated penalties as follows:

i.

Period of Non-Compliance	Penalty per day
Days 1-120	$50
Days 121-180	$100
Days 181 - 365	$300
Over 365 Days	$3,000

or

ii. 1.2 times the economic benefit resulting from ExxonMobil's failure to implement the corrective action(s).

195. For failure to complete any corrective action under Paragraph 81 of this Decree in accordance with the schedule for such corrective action agreed to by ExxonMobil or imposed on ExxonMobil pursuant to the dispute resolution provisions of this Decree (with any such extensions thereto as to which EPA and ExxonMobil may agree in writing):

Period of Non-Compliance	Penalty per day
Days 1-30	$1,000
Days 31-60	$2,000
Over 60	$5,000

K. Requirements for Control of Hydrocarbon Flaring Incidents.

196. For each failure to perform a Root Cause analysis or submit a written report or perform corrective actions for an HC Flaring Incident, as required by Paragraph 92:

Period of Non-Compliance	Penalty per day per Incident
1st through 30th day	$500
31st through 60th day	$1,500
Beyond 60th day	$3,000

L. Requirements for CERCLA/EPCRA Reporting.

197. For failure to perform a CERCLA/EPCRA Compliance Review, submit a CERCLA/EPCRA Compliance Review Report, or perform corrective actions, as required by Paragraph 95, per refinery:

Period of Non-Compliance	Penalty per day per Incident
1st through 30th day	$500
31st through 60th day	$1,500
Beyond 60th day	$3,000

198. For each failure to submit a CERCLA/EPCRA report on a release at the Joliet Refinery, as required by Paragraph 96:

Period of Non-Compliance	Penalty per day per violation
1st through 7th day	$750
8th through 14th day	$1,500
Beyond 14th day	$5,000

ExxonMobil's obligation to pay stipulated penalties under this Paragraph 198 shall cease if: (i) at least thirty-six months have elapsed since the Entry Date; and (ii) stipulated penalties have not been assessed under this Paragraph 198 during the most recent thirty-six months.

M. Requirements for Benzene Waste NESHAP Program Enhancements.

199. For each violation in which a frequency is specified in Subsection V.N., the amounts identified below shall apply on the first day of violation, and shall be calculated for each incremental period of violation (or portion thereof):

a. For failure to complete a BWON Compliance Review and Verification Report as required by Paragraph 100: $7,500 per month, per refinery.

b. For failure to submit a BWON Corrective Measures Plan as required by Subparagraph 101.b, or for failure to implement Plan and to certify compliance as required by Subparagraphs 101.c and 101.d, per refinery:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$1,250
31st through 60th day after deadline	$3,000
Beyond 60th day	$5,000, or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater.

c. For failure to comply with the requirements set forth in Paragraph 102 related to the use, monitoring, and replacement of carbon canisters: $1,000 per incident of non-compliance, per day.

d. For failure to implement the training requirements of Paragraph 106: $10,000 per quarter.

e. For failure to establish an annual review program to identify new benzene waste streams as required by Paragraph 103: $2,500 per month, per refinery.

f. For failure to perform laboratory audits as required by Paragraph 104: $5,000 per month, per audit.

g. For failure to submit or maintain any plans or other deliverables required by Paragraph 107: $2,000 per deliverable.

h. For failure to conduct sampling in accordance with the sampling plans required by Paragraphs 108 or 109: $30,000 per quarter, per stream, whichever is greater, but not to exceed $150,000 per quarter, per refinery.

i. For failure to submit a BWON Corrective Measures Plan or retain the third-party contractor required by Paragraph 111: $10,000 per month.

j. For failure to conduct monthly visual inspections of all Subpart FF water traps as required by Subparagraph 112.a.i: $500 per drain not inspected;

k. For failure to monitor Subpart FF conservation vents as required by Subparagraph 112.a.ii: $500 per vent not monitored;

l. For failure to conduct monitoring of oil-water separators as required by Subparagraph 112.a.iii: $1,000 per month, per unit not monitored;

m. For failure to identify/mark segregated stormwater drains as required in Subparagraph 112.b: $1,000 per week per drain not identified/marked as required;

n. For failure to submit any of the written deliverables required by Subsection V.N (except for those deliverables for which stipulated penalties are specified in Subparagraphs 199.a, 199.b, 199.g, or 199.i): $1,000 per week, per deliverable not submitted.

N. Requirements for Leak Detection and Repair Program Enhancements.

200. For each violation in which a frequency is specified in Subsection V.O the amounts identified below shall apply on the first day of violation, and shall be calculated for each incremental period of violation (or portion thereof):

a. For failure to develop an LDAR Program Description as required by Paragraph 117: $3,500 per week, per refinery.

b. For failure to implement the training program specified in Paragraph 118: $10,000 per month, per refinery.

c. For failure to conduct any of the LDAR Audits described in Paragraph 120: $5,000 per month, per audit, per refinery.

d. For failure to implement any actions necessary to correct non-compliance as required in Paragraph 121:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$1,250
31st through 60th day after deadline	$3,000
Beyond 60th day	$5,000, or an amount equal to 1.2 times the economic benefit of non-compliance, whichever is greater

e. For failure to perform monitoring utilizing the lower internal leak rate definitions as specified in Paragraph 122: $100 per component, but not greater than $10,000 per month, per process unit.

f. For failure to perform LDAR monitoring at the frequency required by Paragraph 123: $100 per component, but not greater than $10,000 per month, per refinery.

g. For failure to make first repair attempts within 5 days and/or take other actions required by Paragraph 124: $100 per component but not greater than $10,000 per month, per refinery (except that Subparagraph 200.h shall apply in lieu of this Subparagraph 200.g where both Subparagraphs are potentially applicable).

h. For failure to implement the "initial attempt" repair program set forth in Paragraph 126: $100 per component, but not to exceed $10,000 per month, per refinery.

i. For failure to implement the QA/QC procedures described in Paragraph 128: $1,000 per incident, but not greater than $10,000 per month, per refinery.

j. For failure to designate a person or position responsible for LDAR management as required by Paragraph 119, or for failure to implement the maintenance tracking program required by Subparagraph 117.iv: $3,500 per week, per refinery.

k. For failure to use dataloggers or maintain electronic data as required by Paragraph 127: $5,000 per month, per refinery.

l. For failure to conduct and record the calibrations and the calibration drift assessments or remonitor valves and pumps based on calibration drift assessments in Paragraph 129: $100 per missed event.

m. For failure to comply with the requirements for delay of repair set forth at Paragraph 130: $5,000 per valve or pump, per incident of non-compliance.

n. For failure to submit a written submission to EPA and/or an Applicable Co-Plaintiff as required by Subsection V.O (except where a more specific stipulated penalty provision applies to a submission under this Subsection XI.N): $500 per week, per submission.

o. If it is determined through a federal, state, or local investigation that ExxonMobil has failed to include any valves or pumps in its LDAR program, ExxonMobil shall pay $175 per component that it failed to include.

p. For failure to comply with the requirements for chronic leakers set forth at Paragraph 131: $5,000 per valve.

O. Other Compliance Program Requirements for the Billings and Joliet Refineries.

201. For failure to comply with the following Joliet Wastewater Treatment Area Program Requirements under Paragraph 134 and Appendix P:

a. For failure to timely submit the WWTP Area Wastewater Monitoring Plan required by Paragraph 2 of Appendix P, or for submitting a WWTP Area Wastewater Monitoring Plan that does not substantially conform to the requirements of this Consent Decree:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

b. For failure to meet the scheduling milestones of the EPA-approved WWTP Area Wastewater Monitoring Plan:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

c. For failure to timely submit a WWTP Area Wastewater Monitoring Plan Quarterly Report required by Paragraph 4 of Appendix P, or for submitting a WWTP Area Wastewater Monitoring Plan Quarterly Report that does not substantially conform to the requirements of Appendix P:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

d. For failure to timely submit the WWTP Area Wastewater Monitoring Plan Final Report required by Paragraph 5 of Appendix P, or for submitting a WWTP Area Wastewater Monitoring Plan Final Report that does not substantially conform to the requirements of Appendix P:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

e. For failure to meet the scheduling milestones contained in the EPA-approved WWTP Area Wastewater Monitoring Plan Final Report:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

f. For failure to timely submit the Sludge Characterization and Removal Plan required by Paragraph 6 of Appendix P, or for submitting a Sludge Characterization and Removal Plan that does not substantially conform to the requirements of Appendix P:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

g. For failure to meet the scheduling milestones contained in the EPA-approved Sludge Characterization and Removal Plan:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

h. For failure to comply with any requirement of Paragraph 7 of Appendix P relating to Aggressive Biological Treatment at the Joliet Refinery EBTU:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

i. For failure to timely submit the Groundwater and Soil Characterization Plan required by Paragraph 8 of Appendix P, or for submitting a Groundwater and Soil Characterization Plan that does not substantially conform to the requirements of Appendix P:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

j. For failure to meet the scheduling milestones contained in the EPA-approved Groundwater and Soil Characterization Plan:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

k. For failure to comply with an effluent limitation specified by the Joliet Refinery NPDES Permit, as required by Subparagraph 3.a of Appendix P:

(1) <u>For a violation of a daily maximum limit:</u>

$2,000 for the first exceedance of a specified effluent limitation at a particular monitoring point;

$4,000 for the second exceedance of the same specified effluent limitation at a particular monitoring point; and

$5,000 for the third exceedance and each subsequent exceedance of the same specified effluent limitation at a particular monitoring point.

(2) For a violation of a 30-day average limit:

$5,000 for the first exceedance of a specified effluent limitation at a particular monitoring point;

$8,000 for the second exceedance of the same specified effluent limitation at a particular monitoring point; and

$10,000 for the third exceedance and each subsequent exceedance of the same specified effluent limitation at a particular monitoring point.

(3) Time Period for Accrual of Stipulated Penalties under this Subparagraph 201.k. Stipulated penalties for any noncompliance with the effluent limitations of the Joliet Refinery NPDES Permit covered by this Subparagraph 201.k shall accrue for at least thirty-six (36) months after the Entry Date, provided that after the initial twenty-four (24) month period, ExxonMobil's obligation to pay stipulated penalties under this Subparagraph 201.k shall cease with respect to a specific effluent limitation at a particular monitoring point at such time that ExxonMobil demonstrates continuous compliance with that effluent limitation at that particular monitoring point as reported in its Discharge Monitoring Reports over a rolling consecutive twelve (12) month period.

202. For failure to comply with any requirement of Paragraph 135 relating to the Joliet Material Staging Area:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

203. For failure to timely submit the materials related to the Joliet RCRA Training Requirements required by Paragraph 136, or for submitting such materials required by Paragraph 136 that do not substantially conform to the requirements of this Consent Decree:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

204. For failure to designate both the Billings Scrap Yard and the Laydown Areas as Solid Waste Management Units and/or Areas of Concern as required under Paragraph 137:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

205. For failure to timely submit modifications to the Billings Stormwater Pollution Prevention Plan required by Subparagraph 137.c, or for submitting such materials required by Paragraph 137.c that do not substantially conform to the requirements of this Consent Decree:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

206. For failure to timely seek amendments to the Billings Refinery RCRA permit related to waste application at the Land Treatment Unit required by Paragraph 138, or for submitting such materials required by Paragraph 138 that do not substantially conform to the requirements of this Consent Decree:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

207. For failure to timely submit proposed amendments to the Billings Refinery Montana Pollutant Discharge Elimination System Permit related to oil sheen required by Paragraph 139, or for submitting such materials required by Paragraph 139 that do not substantially conform to the requirements of this Consent Decree:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

208. For failure to comply with any requirement of Paragraph 140 relating to Billings Refinery Tank 350:

Period of Non-Compliance	Penalty per day
Days 1-30	$750
Days 31-60	$1,500
Over 60 days	$3,000

P. Requirements to Incorporate Consent Decree Requirements into Federally-Enforceable Permits.

209. For each failure to submit an application as required by Paragraphs 141 and 142:

Period of Non-Compliance	Penalty per day
Days 1-30	$800
Days 31-60	$1,500
Over 60 Days	$3,000

Q. Requirements for Reporting and Recordkeeping.

210. For failure to submit reports as required by Section IX, per report, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$300
31st through 60th day after deadline	$1,000
Beyond 60th day	$2,000

R. Requirements for Environmentally Beneficial Projects and Civil Penalties.

211. For failure to timely complete implementation of a SEP required under Section VIII, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$1,000
31st through 60th day after deadline	$1,500
Beyond 60th day	$2,000

212. For failure to make any civil penalty payment required by Paragraph 162 of this Consent Decree, ExxonMobil shall be liable for $15,000 per day, and interest on the amount overdue at the rate specified in 28 U.S.C. § 1961(a).

S. Requirement to Pay Stipulated Penalties.

213. ExxonMobil shall be liable for $2,500 per day, and interest on the amount overdue at the rate specified in 28 U.S.C. § 1961(a), for failure to do either of the following within sixty (60) days after receipt of a written demand pursuant to Paragraph 214: (i) pay stipulated penalties as required by Paragraph 165 of this Consent Decree; or (ii) place the amount of stipulated penalties demanded in escrow pursuant to Paragraph 215.

T. Payment of Stipulated Penalties.

214. ExxonMobil shall pay stipulated penalties (as required under Paragraph 165) upon written demand by the United States or the Applicable Co-Plaintiff no later than sixty (60) days after ExxonMobil receives such demand. Demand from either the United States or an Applicable Co-Plaintiff shall be deemed a demand from both, but the United States and the Applicable Co-Plaintiff shall consult with each other prior to making a demand. If there is no Applicable Co-Plaintiff, stipulated penalties owed by ExxonMobil shall be paid 100 percent to the United States. If there is an Applicable Co-Plaintiff, stipulated penalties owed by

ExxonMobil shall be paid 50 percent to the United States and 50 percent to the Applicable Co-Plaintiff. Stipulated penalties shall be paid to the United States and to the Applicable Co-Plaintiff in the manner set forth in Section X (Civil Penalty) of this Consent Decree. A demand for the payment of stipulated penalties will identify the particular violation(s) to which the stipulated penalty relates, the stipulated penalty amount the United States or the Applicable Co-Plaintiff 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. After consultation with each other, the United States and the Applicable Co-Plaintiff may, in their unreviewable discretion, waive payment of any portion of stipulated penalties that may accrue under this Consent Decree.

U. <u>Stipulated Penalties Dispute</u>.

215. Should ExxonMobil dispute the United States' and/or an Applicable Co-Plaintiff's demand for all or part of a stipulated penalty, it may avoid the imposition of a stipulated penalty for failure to pay a stipulated penalty under Paragraph 213 by placing the disputed amount demanded in a commercial escrow account pending resolution of the matter and by invoking the dispute resolution provisions of Section XV within the time provided in Paragraph 214 for payment of stipulated penalties. If the dispute is thereafter resolved in ExxonMobil's favor, the escrowed amount plus accrued interest shall be returned to ExxonMobil; otherwise, the United States and the Applicable Co-Plaintiff shall 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. The United States and the Applicable Co-Plaintiff reserve the right to pursue any other non-monetary remedies to which they are legally entitled, including but not limited to, injunctive relief for ExxonMobil's violations of this Consent Decree.

XII. INTEREST

216. After the date on which a payment is due under this Consent Decree, ExxonMobil shall be liable for interest on the unpaid balance of the civil penalty specified in Section X, and for interest on any unpaid balance of stipulated penalties to be paid in accordance with Section XI. All such interest shall 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 shall be computed daily and compounded annually. Interest shall be calculated from the date payment is due under the Consent Decree through the date of actual payment. For purposes of this Section XII, 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 215 of the Consent Decree. Monies timely paid into escrow shall not be considered to be an unpaid balance under this Section.

XIII. RIGHT OF ENTRY

217. Any authorized representative of EPA or an Applicable Co-Plaintiff, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of the facilities of any Covered Refinery, at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment, and inspecting and copying all records maintained by ExxonMobil pursuant to the requirements of this Consent Decree or in the ordinary course of ExxonMobil's business that are deemed necessary by EPA or the Applicable Co-Plaintiff to verify compliance with this Consent Decree. ExxonMobil shall retain records required under this Consent Decree for the period of

the Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA or an Applicable Co-Plaintiff to conduct tests, inspections, or other activities under any statutory or regulatory provision.

XIV. FORCE MAJEURE

218. If any event occurs which causes or may cause a delay or impediment to performance in complying with any provision of this Consent Decree, ExxonMobil shall notify EPA and the Applicable Co-Plaintiff in writing as soon as practicable, but in any event within ten (10) business days of the date when ExxonMobil first knew of the event or should have known of the event by the exercise of due diligence. In this notice, ExxonMobil shall specifically reference this Paragraph 218 of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, and the measures taken or to be taken by ExxonMobil to prevent or minimize the delay and the schedule by which those measures shall be implemented. ExxonMobil shall take all reasonable steps to avoid or minimize such delays. The notice required by this Section shall be effective upon the mailing of the same by certified mail, return receipt requested, to EPA and the Applicable Co-Plaintiff as specified in Paragraph 266 (Notice).

219. Failure by ExxonMobil to substantially comply with the notice requirements of Paragraph 218 as specified above shall render this Section XIV (Force Majeure) voidable by the United States, in consultation with the Applicable Co-Plaintiff, as to the specific event for which ExxonMobil has failed to comply with such notice requirement, and, if voided, is of no effect as to the particular event involved.

220. The United States, after consultation with the Applicable Co-Plaintiff, shall notify ExxonMobil in writing regarding its claim of a delay or impediment to performance within thirty (30) days of receipt of the force majeure notice provided under Paragraph 218.

221. If the United States, after consultation with the Applicable Co-Plaintiff, agrees that the delay or impediment to performance has been or will be caused by circumstances beyond the control of ExxonMobil, including any entity controlled by ExxonMobil, and that ExxonMobil could not have prevented the delay by the exercise of due diligence, the Parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay by a period equivalent to the delay actually caused by such circumstances or such other period as may be appropriate under the circumstances. Such stipulation shall be filed as a modification to the Consent Decree pursuant to the modification procedures established in this Consent Decree. ExxonMobil shall not be liable for stipulated penalties for the period of any such delay.

222. If the United States, after consultation with the Applicable Co-Plaintiff, does not accept ExxonMobil's claim of a delay or impediment to performance, ExxonMobil must submit the matter to the Court for resolution to avoid payment of stipulated penalties, by filing a petition for determination with the Court. In the event the United States and the Applicable Co-Plaintiff do not agree, the position of the United States on the force majeure claim shall become the final Plaintiffs' position. Once ExxonMobil has submitted this matter to the Court, the United States and the Applicable Co-Plaintiff shall have twenty (20) business days to file their responses to the petition. If the Court determines that the delay or impediment to performance has been or will be caused by circumstances beyond the control of ExxonMobil, including any entity controlled by ExxonMobil, and that the delay could not have been prevented by ExxonMobil by the

exercise of due diligence, ExxonMobil shall be excused as to that event(s) and delay (including stipulated penalties), for all requirements affected by the delay for a period of time equivalent to the delay caused by such circumstances or such other period as may be determined by the Court.

223. ExxonMobil shall bear the burden of proving that any delay in meeting any requirement(s) of this Consent Decree was caused by or will be caused by circumstances beyond its control, including any entity controlled by it, and that it could not have prevented the delay by the exercise of due diligence. ExxonMobil shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date or dates.

224. Unanticipated or increased costs or expenses associated with the performance of ExxonMobil's obligations under this Consent Decree shall not constitute circumstances beyond its control, or serve as the basis for an extension of time under this Section XIV.

225. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either Party as a result of ExxonMobil serving a force majeure notice or the Parties' inability to reach agreement.

226. As part of the resolution of any matter submitted to this Court under this Section XIV, the Parties by agreement, or the Court, by order, may in appropriate circumstances extend or modify the schedule for completion of work under the Consent Decree to account for the delay in the work that occurred or will occur as a result of any delay or impediment to performance agreed to by the United States or approved by this Court. ExxonMobil shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XV. RETENTION OF JURISDICTION / DISPUTE RESOLUTION

227. This Court shall retain jurisdiction of this matter for the purposes of implementing and enforcing the terms and conditions of the Consent Decree and for the purpose of adjudicating all disputes – including, but not limited to, determinations under Section V (Affirmative Relief) of the Consent Decree – among the Parties that may arise under the provisions of the Consent Decree, until the Consent Decree terminates in accordance with Section XVIII (Termination).

228. The dispute resolution procedure set forth in this Section XV shall be available to resolve all disputes arising under this Consent Decree, except only as otherwise provided in Section XIV regarding force majeure, provided that the Party making such application has made a good faith attempt to resolve the matter with the other Party.

229. Dispute resolution shall be commenced by one of the Parties under the Consent Decree by giving written notice to another Party advising of a dispute pursuant to this Section XV. The notice shall describe the nature of the dispute, and shall state the noticing Party's position with regard to such dispute. The Party receiving such a notice shall acknowledge receipt of the notice and the Parties shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days after the receipt of such notice.

230. Disputes submitted to dispute resolution shall, in the first instance, be the subject of informal negotiations between the Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the Parties, unless the Parties agree that this period should be extended.

231. In the event that the Parties are unable to reach agreement during such informal negotiation period, the United States or the Applicable Co-Plaintiff, as applicable, shall provide

ExxonMobil with a written summary of its position regarding the dispute. The position advanced by the United States or the Applicable Co-Plaintiff, as applicable, shall be considered binding unless, within forty-five (45) calendar days of ExxonMobil's receipt of the written summary of the United States' or the Applicable Co-Plaintiff's position, ExxonMobil files with the Court a petition which describes the nature of the dispute. The United States and/or the Applicable Co-Plaintiff shall respond to the petition within forty-five (45) calendar days of filing.

232. In the event that the United States and an Applicable Co-Plaintiff make differing determinations or take differing actions that affect ExxonMobil's rights or obligations under this Consent Decree, the determination or action of the United States shall control.

233. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set forth in this Section XV may be shortened upon motion of one of the Parties to the dispute.

234. The Parties do not intend that the invocation of this Section XV by a Party cause the Court to draw any inferences nor establish any presumptions adverse to either Party as a result of invocation of this Section or their inability to reach agreement.

235. As part of the resolution of any dispute submitted to dispute resolution, the Parties, by agreement, or this 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 the work that occurred as a result of dispute resolution. ExxonMobil shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XVI. EFFECT OF SETTLEMENT

236. **Definitions**. For purposes of this Section XVI, the following definitions apply:

a. "Applicable NSR/PSD Requirements" shall mean:

(i) PSD requirements at Part C of Subchapter I of the Act, 42 U.S.C. § 7475, and the regulations promulgated thereunder at 40 C.F.R. §§ 52.21 and 51.166, as amended from time to time;

(ii) "Plan Requirements for Non-Attainment Areas" at Part D of Subchapter I of the Act, 42 U.S.C. §§ 7502-7503, and the regulations promulgated thereunder at 40 C.F.R. §§ 51.165 (a) and (b); 40 C.F.R. Part 51, Appendix S; and 40 C.F.R. § 52.24, as amended from time to time;

(iii) Any Title V regulations that implement, adopt, or incorporate the specific regulatory requirements identified above, as amended from time to time; and

(iv) Any applicable state or local laws or regulations that implement, adopt, or incorporate the specific federal regulatory requirements identified above regardless of whether such state or local laws or regulations have been formally approved by EPA as being a part of the applicable state implementation plan.

b. "Applicable NSPS Subparts A and J Requirements" shall mean the standards, monitoring, testing, reporting and recordkeeping requirements, found at 40 C.F.R. §§ 60.100 through 60.109 (Subpart J), relating to a particular pollutant and a particular affected facility, and the corollary general requirements found at 40 C.F.R. §§ 60.1 through 60.19 (Subpart A) that are applicable to any affected facility covered by Subpart J.

c. "Benzene Waste NESHAP Requirements" shall mean the requirements imposed by the National Emission Standard for Benzene Waste Operations, 40 C.F.R. Part 61, Subpart FF, and any applicable state, regional, or local regulations that implement, adopt or incorporate the Benzene Waste NESHAP.

d. "CERCLA/EPCRA Requirements" shall mean the reporting requirements for a given release of a hazardous substance imposed by Section 103(a) of CERCLA, 42 U.S.C. § 9603(a), and Section 304 of EPCRA, 42 U.S.C. § 11004.

e. "LDAR Requirements" shall mean the requirements relating to equipment in light liquid service and gas and/or vapor service set forth at 40 C.F.R. Part 60, Subpart GGG; 40 C.F.R. Part 61, Subparts J and V; and 40 C.F.R. Part 63, Subparts F, H, and CC; and any applicable state, regional, or local regulations or State Implementation Plan requirements that implement, adopt or incorporate those federal regulations.

f. "Post-Lodging Compliance Dates" shall mean any dates in this Section XVI after the Date of Lodging (and/or after the Entry Date). Post-Lodging Compliance Dates include dates certain (e.g., "December 31, 2005"), dates after Lodging represented in terms of time after the Date of Lodging or the Entry Date (e.g., "180 days after the Date of Lodging" or "180 days after the Entry Date"), and dates after Lodging represented by actions taken (e.g., "Date of Certification"). The Post-Lodging Compliance Dates represent the dates by which work is required to be completed or an emission limit is required to be met under the applicable provisions of this Consent Decree.

237. **Liability Resolution Regarding the Applicable NSR/PSD Requirements.** With respect to emissions of the following pollutants from the following units, entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the United States and the Applicable Co-Plaintiffs for alleged violations of the Applicable NSR/PSD Requirements resulting from construction or modification from the date of the pre-Lodging construction or modification up to the following dates:

Unit	Pollutant	Date
Baton Rouge PCLA 2	SO_2	January 1, 2006
	NOx	455 days after the Entry Date
Baton Rouge PCLA 3	SO_2	January 1, 2006
	NOx	455 days after the Entry Date
Baytown FCCU 2	SO_2	December 31, 2009
	NOx	June 30, 2010
Baytown FCCU 3	SO_2	Entry Date
	NOx	June 30, 2010
Beaumont FCCU	SO_2	Entry Date
	NOx	October 1, 2009
Billings FCCU	SO_2	Either: (i) March 15, 2012, if the Final SO_2 Limit is established by election of Option A under Subparagraph 29.b.(1); <u>or</u> (ii) the date on which a Final SO_2 Limit is established by election of Option B under Subparagraph 29.b.(2)
	NOx	December 31, 2008
Joliet FCCU	SO_2	December 31, 2008
	NOx	December 31, 2012
Torrance FCCU	SO_2	Entry Date
	NOx	Entry Date
All Combustion Devices listed in Appendix A	NOx	September 30, 2010
All heaters and boilers other than those in Appendix A	NOx	Entry Date
All heaters and boilers listed in Appendix C	SO_2	Dates listed in or derived from Appendix C
All heaters and boilers other than those listed in Appendix C	SO_2	Entry Date

All Other Fuel Gas Combustion Devices listed in Appendix D	SO_2	Dates listed in or derived from Appendix D

238. **Conditional Resolution of Liability for PM Emissions Under the Applicable NSR/PSD Requirements.** With respect to emissions of PM from an FCCU at a Covered Refinery, if and when ExxonMobil accepts an emission limit of 0.5 pound PM per 1000 pounds of coke burned for the particular FCCU pursuant to Paragraph 35 and demonstrates compliance by conducting a performance test representative of normal operating conditions for the particular FCCU, then all civil liability of ExxonMobil to the United States and to the Applicable Co-Plaintiffs shall be resolved for alleged violations of the Applicable NSR/PSD Requirements relating to PM emissions at the particular FCCU resulting from pre-Lodging construction or modification of the particular FCCU.

239. **Conditional Resolution of Liability for CO Emissions Under the Applicable NSR/PSD Requirements.** With respect to emissions of CO from an FCCU at a Covered Refinery, if and when ExxonMobil accepts the following long-term and short-term emission limits at the particular FCCU pursuant to Paragraph 40 and demonstrates compliance using CEMS or, where applicable, an AMP at the particular FCCU, then all civil liability of ExxonMobil to the United States and to the Applicable Co-Plaintiffs shall be resolved for alleged violations of the Applicable NSR/PSD Requirements relating to CO emissions at the particular FCCU resulting from pre-Lodging construction or modification of the particular FCCU:

Long-term limit: 150 ppmvd CO on a 365-day rolling average basis at 0% O_2

Short-term limit: 250 ppmvd CO on a 24-hour rolling average basis at 0% O_2

240. **<u>Reservation of Rights regarding Applicable NSR/PSD Requirements: Release for Violations Continuing After the Date of Lodging Can be Rendered Void</u>**. Notwithstanding the resolution of liability in Paragraphs 237, 238, and 239, the release of liability by the United States and the Applicable Co-Plaintiffs to ExxonMobil for alleged violations of the Applicable NSR/PSD Requirements during the period between the Date of Lodging of the Consent Decree and the Post-Lodging Compliance Dates shall be rendered void for a particular emissions unit if ExxonMobil materially fails to comply with the obligations and requirements of Subsections V.B - V.E and V.G for that unit; <u>provided</u>, <u>however</u>, that the release in Paragraphs 237, 238, and 239, shall not be rendered void if ExxonMobil remedies such material failure and pays any stipulated penalties due as a result of such material failure.

241. **<u>Exclusions from Release Coverage Regarding Applicable NSR/PSD Requirements: Construction and/or Modification Not Covered by Paragraphs 237, 238, and 239</u>.** Notwithstanding the resolution of liability in Paragraphs 237, 238, and 239, nothing in this Consent Decree precludes the United States and/or the Applicable Co-Plaintiffs from seeking from ExxonMobil, injunctive relief, penalties, or other appropriate relief for violations by ExxonMobil of the Applicable NSR/PSD Requirements resulting from construction or modification that: (i) commenced prior to or commences after the Date of Lodging of the Consent Decree for pollutants or units not covered by the Consent Decree; or (ii) commences after the Date of Lodging of the Consent Decree for units covered by this Consent Decree.

242. **<u>Evaluation of Applicable PSD/NSR Requirements Must Occur</u>.** Increases in emissions from units covered by this Consent Decree, where the increases result from the Post-Lodging construction or modification of any units within any Covered Refinery, are beyond

the scope of the release in Paragraphs 237, 238, and 239, and ExxonMobil must evaluate any such increases in accordance with the Applicable PSD/NSR Requirements.

243. **Resolution of Liability Regarding Applicable NSPS Subparts A and J Requirements.** With respect to emissions of the following pollutants from the following units, entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the United States and the Applicable Co-Plaintiffs for alleged violations of the Applicable NSPS Subparts A and J Requirements from the date that claims of the United States and the Applicable Co-Plaintiffs resulting from pre-Lodging construction or modification (including reconstruction) accrued up to the following dates:

Unit	Pollutant	Date
Baton Rouge PCLA 2	SO_2	January 1, 2006
Baton Rouge PCLA 3	SO_2	January 1, 2006
Baytown FCCU 2	SO_2	December 31, 2006
	PM	December 31, 2009
	CO	Entry Date
	Opacity	Date of AMP Approval Receipt
Baytown FCCU 3	SO_2	Entry Date
	PM	Entry Date
	CO	Entry Date
	Opacity	Date of AMP Approval Receipt
Beaumont FCCU	SO_2	Entry Date
	PM	Entry Date
	CO	Entry Date
	Opacity	Date of AMP Approval Receipt
Billings FCCU	PM	December 31, 2006 or December 31, 2008 (depending on the deadline ultimately required by Subparagraph 34.b)
	CO	18 months after Entry Date
	Opacity	December 31, 2006

Joliet FCCU	SO_2 PM CO Opacity	December 31, 2008 Entry Date 18 months after Entry Date Entry Date
Torrance FCCU	SO_2 PM CO Opacity	Entry Date Entry Date Entry Date Entry Date
All heaters and boilers listed in Appendix C	SO_2	Dates listed in or derived from Appendix C
All heaters and boilers other than those listed in Appendix C	SO_2	Entry Date
All Other Fuel Gas Combustion Devices listed in Appendix D	SO_2	Dates listed in or derived from Appendix D
Baytown SRP	SO_2	Entry Date
Beaumont SRP	SO_2	Entry Date
Joliet SRP	SO_2	December 31, 2008
Torrance SRP	SO_2	Entry Date
NSPS Flaring Devices Listed in Appendix G	SO_2	Dates listed in or derived from Appendix G

244. **Reservation of Rights regarding Applicable NSPS Subparts A and J Requirements: Release for NSPS Violations Occurring After the Date of Lodging Can be Rendered Void.** Notwithstanding the resolution of liability in Paragraphs 243, the release of liability by the United States and the Applicable Co-Plaintiffs to ExxonMobil for alleged violations of any Applicable NSPS Subparts A and J Requirements that occurred between the Date of Lodging and the Post-Lodging Compliance Dates shall be rendered void for a particular

emissions unit if ExxonMobil materially fails to comply with the obligations and requirements of Subsections V.F, V.H, V.I, V.J, V.K, and V.L, and Paragraphs 44-46 and 48-49 for that unit; provided, however, that the release in Paragraph 243 shall not be rendered void if ExxonMobil remedies such material failure and pays any stipulated penalties due as a result of such material failure.

245. **Conditional Resolution of Liability for the Applicable NSPS Subparts A and J Requirements for SO_2 for the Billings FCCU.** With respect to emissions of SO_2 from the Billings FCCU, if and when ExxonMobil elects to classify the Billings FCCU catalyst regenerator as an "affected facility," as that term is used in the Applicable NSPS Subparts A and J Requirements for SO_2, and demonstrates compliance as required by the Applicable NSPS Subparts A and J Requirements for SO_2, then all civil liability of ExxonMobil to the United States and to the Applicable Co-Plaintiff shall be resolved for alleged violations of the Applicable NSPS Subparts A and J Requirements for SO_2 at the Billings FCCU catalyst regenerator resulting from pre-Lodging construction or modification (including reconstruction) of the Billings FCCU catalyst regenerator.

246. **Resolution of Liability for Certain Potential NSPS Violations Relating to the Baton Rouge Refinery.**

a. A single TGU serves as the control device for the 100 Claus Train, the 200 Claus Train, and the 400 Claus Train at the Baton Rouge Refinery.

b. The Baton Rouge 100 Claus Train and 200 Claus Train were constructed in 1972.

c. Between 1976 and 1979, ExxonMobil: (i) began operating the Baton Rouge TGU; (ii) constructed the 400 Claus Train; and (iii) began routing Tail Gas from the 100

Claus Train, the 200 Claus Train, and the 400 Claus Train to the TGU. Those physical changes in, and/or changes in the method of operation of, and/or replacement of components are referred to collectively in this Paragraph as the "Specified Baton Rouge Sulfur Recovery Project."

d. Entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the United States and the Applicable Co-Plaintiffs for potential violations of the Applicable NSPS Subparts A and J Requirements resulting from the Specified Baton Rouge Sulfur Recovery Project.

246A. **Conditional Resolution of Liability for the Applicable NSPS Subparts A and J Requirements for CO for the Baton Rouge FCCUs.** With respect to emissions of CO from the Baton Rouge FCCUs, if at any time prior to termination ExxonMobil elects to classify each of the Baton Rouge FCCUs' catalyst regenerators as an "affected facility," as that term is used in the Applicable NSPS Subparts A and J Requirements for CO, and demonstrates initial compliance as required by the Applicable NSPS Subparts A and J Requirements for CO, then all civil liability of ExxonMobil to the United States and to the Applicable Co-Plaintiff shall be resolved for alleged violations of the Applicable NSPS Subparts A and J Requirements for CO at the Baton Rouge FCCUs resulting from Pre-Lodging construction or modification (including reconstruction) of the Baton Rouge FCCU catalyst regenerators.

246B. **Conditional Resolution of Liability for the Applicable NSPS Subparts A and J Requirements for PM for the Baton Rouge FCCUs.** With respect to emissions of PM from the Baton Rouge FCCUs, if at any time prior to termination ExxonMobil elects to classify each of the Baton Rouge FCCUs' catalyst regenerators as an "affected facility," as that term is used in the Applicable NSPS Subparts A and J Requirements for PM, and demonstrates initial compliance as required by the Applicable NSPS Subparts A and J Requirements for PM, then all civil liability of ExxonMobil to the United States and to the Applicable Co-Plaintiff shall be resolved for alleged violations of the Applicable NSPS Subparts A and J Requirements for PM at the Baton Rouge FCCUs resulting from Pre-Lodging construction or modification (including reconstruction) of the Baton Rouge FCCU catalyst regenerators.

246C. **Conditional Resolution of Liability for the Applicable NSPS Subparts A and J Requirements for Opacity for the Baton Rouge FCCUs.** With respect to emissions of opacity from the Baton Rouge FCCUs, if at any time prior to termination ExxonMobil elects to classify each of the Baton Rouge FCCUs' catalyst regenerators as an "affected facility," as that term is used in the Applicable NSPS Subparts A and J Requirements for opacity, and demonstrates initial compliance with the Applicable NSPS Subparts A and J Requirements for opacity using an approved AMP, then all civil liability of ExxonMobil to the United States and to the Applicable Co-Plaintiff shall be resolved for alleged violations of the Applicable NSPS Subparts A and J Requirements for opacity at the Baton Rouge FCCUs resulting from Pre-Lodging construction or modification (including reconstruction) of the Baton Rouge FCCU catalyst regenerators.

247. **Prior NSPS Applicability Determinations.** Nothing in this Consent Decree shall affect the status of any FCCU, fuel gas combustion device, or sulfur recovery plant currently subject to NSPS as previously determined by any federal, state, or local authority or any applicable permit.

248. **Resolution of Liability Regarding CERCLA/EPCRA Requirements for Certain Pre-Lodging Acid Gas Flaring Incidents.** Upon receipt by EPA of ExxonMobil's CERCLA/EPCRA Compliance Review Report submitted pursuant to Paragraph 95, this Consent Decree shall resolve all civil liability of ExxonMobil to the United States and the Applicable Co-

Plaintiffs for alleged violations of CERCLA/EPCRA Requirements associated with SO_2 and H_2S releases resulting from pre-Lodging Acid Gas Flaring Incidents at the Baton Rouge, Baytown, Beaumont, Billings, and Joliet Refineries to the extent that ExxonMobil has identified such violations in its CERCLA/EPCRA Compliance Review Report and corrected the violations as required by Paragraph 95.

249. **Resolution of Liability Regarding Benzene Waste NESHAP Requirements.** Entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the United States and the Applicable Co-Plaintiffs for alleged violations of Benzene Waste NESHAP Requirements at the Covered Refineries that either: (i) commenced and ceased prior to the Consent Decree Entry Date; or (ii) are based on events identified in the BWON Compliance Review and Verification Report required under Paragraph 100 and are corrected pursuant to the requirements of Paragraph 101.

250. **Resolution of Liability Regarding LDAR Requirements.** Entry of this Consent Decree shall resolve the civil liability of ExxonMobil to the United States and the Applicable Co-Plaintiffs for alleged violations of LDAR Requirements at the Covered Refineries that either: (i) commenced and ceased prior to the Consent Decree Entry Date; or (ii) are based on events that are identified in the LDAR Initial Audit Report required under Subparagraph 120.b and are corrected pursuant to the requirements of Paragraph 121.

251. **Reservation of Rights Regarding CERCLA/EPCRA Requirements, Benzene Waste NESHAP Requirements, and LDAR Requirements.** Notwithstanding the resolution of liability in Paragraphs 248, 249, and 250, nothing in this Consent Decree precludes the United States and/or the Applicable Co-Plaintiffs from seeking from ExxonMobil civil penalties and/or injunctive relief and/or other equitable relief for violations by ExxonMobil of CERCLA/EPCRA

Requirements, Benzene Waste NESHAP Requirements, or LDAR Requirements that either (i) commenced prior to the Consent Decree Entry Date and continued after the Entry Date; or (ii) commenced after the Consent Decree Entry Date:

i. if ExxonMobil fails to identify any such violation of CERCLA/EPCRA Requirements in its CERCLA/EPCRA Compliance Review Report and correct such violation as required by Paragraph 95;

ii. if ExxonMobil fails to identify any such violation of Benzene Waste NESHAP Requirements in its BWON Compliance Review and Verification Report under Paragraph 100 and correct such violation as required by Paragraph 101; or

iii. if ExxonMobil fails to identify any such violation of LDAR Requirements in its LDAR Initial Audit Report required under Subparagraph 120.b and correct such violation as required by Paragraph 121.

252. **Resolution of Liability for Certain Other Alleged Violations**.

a. Claims Alleged in Certain EPA Notices of Violation and Findings of Violation. Entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the United States and to the Applicable Co-Plaintiffs for the alleged past violations set forth in: (i) Notice of Violation EPA-5-00-IL-26 (dated August 29, 2000); (ii) Finding of Violation EPA-5-00-IL-27 (dated August 29, 2000); (iii) Finding of Violation EPA-5-00-IL-28 (dated August 29, 2000); (iv) EPA's Notice of Violation relating to the Baytown Refinery (dated January 19, 2001); (v) EPA's Notice of Violation relating to the Beaumont Refinery (dated December 20, 2001); and (vi) EPA's Notice of Violation and Finding of Violation relating to the Baton Rouge, Baytown, Beaumont, and Joliet Refineries (dated August 20, 2002).

b. Additional Claims Concerning the Billings Refinery. Entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the United States and the Applicable Co-Plaintiff for the following alleged past violations: (i) alleged violations of the CWA, 33 U.S.C. § 1251 et seq., identified during the June 2002 and/or July 2002 EPA inspections at the Billings Refinery, as listed in Appendix I; (ii) alleged violations of RCRA, 42 U.S.C. § 6901 et seq., identified during the June 2002 and/or July 2002 EPA inspections at the Billings Refinery, as listed in Appendix I; (iii) alleged violations of release reporting requirements under CERCLA Section 103, 42 U.S.C. § 9603, and EPCRA Section 304, 42 U.S.C. § 11004, identified during the June 2002 and/or July 2002 EPA inspections at the Billings Refinery; and (iv) violations of any corresponding state or local laws or regulations arising out of any acts or omissions by ExxonMobil which formed the basis for such alleged CWA, RCRA, and CERCLA and EPCRA violations.

c. Additional Claims Concerning the Joliet Refinery.

(1) Entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the United States and the Applicable Co-Plaintiff for the following alleged past violations: (i) alleged violations of RCRA, 42 U.S.C. § 6901 et seq., based on alleged past unauthorized treatment, storage, and/or disposal of hazardous waste in the diversion basin and/or the equalization/biological treatment unit at Joliet Refinery; (ii) alleged violations of RCRA, 42 U.S.C. § 6901 et seq., based on alleged past unauthorized treatment, storage, and/or disposal of certain hazardous paint wastes and/or certain hazardous sludge wastes on the Joliet Refinery's Material Staging Area; (iii) alleged violations of the CWA, 33 U.S.C. § 1251 et seq., based on alleged past unauthorized discharge of pollutants from the Joliet Refinery's coke pile to navigable waters of the United States; (iv) alleged violations of the CWA, 33 U.S.C. § 1251 et seq., based on alleged past unpermitted discharge of pollutants or discharge of pollutants in excess of the allowable permit limits to navigable waters of the United States, as listed in the table of alleged violations attached as Appendix J; (v) alleged violations of the CWA,

33 U.S.C. § 1251 et seq., based on any alleged past exceedance of combined outfall temperature limits imposed by Special Condition 2 of the Joliet Refinery's NPDES Permit between May 1996 and October 2004; (vi) alleged violations of reporting requirements under CERCLA Section 103, 42 U.S.C. § 9603, and EPCRA Section 304, 42 U.S.C. § 11004, listed in the table of alleged violations attached as Appendix K; and (vii) violations of any corresponding state or local laws or regulations arising out of any acts or omissions by ExxonMobil which formed the basis for such alleged RCRA, CWA, and CERCLA and EPCRA violations.

(2) Entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the Applicable Co-Plaintiff for the alleged past violations at the Joliet Refinery specified in Appendix L.

d. Additional Claims Concerning the Baton Rouge Refinery. Entry of this Consent Decree shall resolve all civil liability of ExxonMobil to the Applicable Co-Plaintiff for the alleged past violations at the Baton Rouge Refinery specified in Appendix M.

253. **Audit Policy.** Nothing in this Consent Decree is intended to limit or disqualify ExxonMobil, on the grounds that information was not discovered and supplied voluntarily, from seeking to apply EPA's Audit Policy or any state audit policy to any violations or non-compliance that ExxonMobil discovers during the course of any investigation, audit, or enhanced monitoring that ExxonMobil is required to undertake pursuant to this Consent Decree.

254. **Claim/Issue Preclusion.** In any subsequent administrative or judicial proceeding initiated by the United States or any Applicable Co-Plaintiff for injunctive relief, penalties, or other appropriate relief relating to ExxonMobil for alleged violations of the

PSD/NSR, NSPS, NESHAP, and/or LDAR requirements, not identified in this Section XVI of the Consent Decree and/or the Complaint:

a. ExxonMobil shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, res judicata, collateral estoppel, issue preclusion, or claim-splitting. Nor may ExxonMobil assert, or maintain, any other defenses based upon any contention that the claims raised by the United States or the Applicable Co-Plaintiffs in the subsequent proceeding were or should have been brought in the instant case. Nothing in the preceding sentences is intended to affect the ability of ExxonMobil to assert that the claims are deemed resolved by virtue of this Section XVI of the Consent Decree.

b. The United States and Applicable Co-Plaintiffs may not assert or maintain that this Consent Decree constitutes a waiver or determination of, or otherwise obviates, any claim or defense whatsoever, or that this Consent Decree constitutes acceptance by ExxonMobil of any interpretation or guidance issued by EPA related to the matters addressed in this Consent Decree.

255. **Imminent and Substantial Endangerment.** Nothing in this Consent Decree shall be construed to limit the authority of the United States or of the Applicable Co-Plaintiffs to undertake any action against any person, including ExxonMobil, to abate or correct conditions which may present an imminent and substantial endangerment to the public health, welfare, or the environment.

XVII. GENERAL PROVISIONS

256. **Other Laws.** Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve ExxonMobil of its obligation to comply with all applicable federal, state and local laws and regulations, permits, and administrative orders, including, but

not limited to, more stringent standards. In addition, nothing in this Consent Decree shall be construed to prohibit or prevent the United States or the Co-Plaintiffs 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 and regulations. In addition, except as otherwise expressly provided in this Consent Decree, nothing in this Consent Decree is intended to eliminate, limit or otherwise restrict any compliance options, exceptions, exclusions, waivers, variances, or other right otherwise provided or available to ExxonMobil under any applicable statute, regulation, ordinance, regulatory or statutory determination, or permitting process. Subject to Section XVI (Effect of Settlement) and except as provided under Section XI (Stipulated Penalties), nothing contained in this Consent Decree shall be construed to prevent, alter or limit the United States' and the Applicable Co-Plaintiff's rights to seek or obtain other remedies or sanctions against ExxonMobil available under other federal, state or local statutes or regulations, in the event that ExxonMobil violates this Consent Decree or the statutes and regulations applicable to violations of this Consent Decree. This shall include the United States' and the Applicable Co-Plaintiff's right to invoke the authority of the Court to order ExxonMobil's compliance with this Consent Decree in a subsequent contempt action.

256A. **<u>Changes to Law</u>.** In the event that during the term of this Consent Decree there is a change in the statutes or regulations that provide the underlying basis for the Consent Decree such that ExxonMobil 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, ExxonMobil may petition the Court for relief from any such requirements, in accordance with Rule 60 of the Federal Rules of Civil Procedure. However, if ExxonMobil applies to the Court for relief under this Paragraph, the United States and the Applicable Co-Plaintiff reserve the right to seek to void all or part of the resolution of liability reflected in Section XVI (Effect of Settlement). Nothing in this Paragraph is intended to enlarge the Parties' rights under Rule 60, nor is this Paragraph intended to confer on any Party any independent basis, outside of Rule 60, for seeking such relief. This Paragraph 256A does not apply to ExxonMobil's obligation to complete the environmentally beneficial projects referred to in Section VIII of this Consent Decree.

257. **Post-Permit Violations.** Nothing in this Consent Decree shall be construed to prevent or limit the right of the United States or the Applicable Co-Plaintiffs to seek injunctive or monetary relief for violations of permits issued as a result of the procedure required under Subsection V.Q of this Decree; provided, however, that with respect to civil monetary relief, the United States or the Applicable Co-Plaintiff 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).

258. **Compliance with Certain Emission Limits.**

a. For the purposes of determining compliance with rolling average limits required under this Consent Decree: (i) at least 365 days is required after the initial compliance date for an applicable 365-day rolling average limit in order to have sufficient data to evaluate compliance with such 365-day rolling average limit; and (ii) at least 7 days is required after the initial compliance date for an applicable 7-day rolling average limit in order to have sufficient data to evaluate compliance with a 7-day rolling average limit. Accordingly: (i) each applicable 365-day rolling average limit shall become enforceable commencing 365 days after the date set forth in this Consent Decree as the date by which ExxonMobil shall begin complying with such limit; and (ii) each applicable 7-day rolling average limit set out above shall become enforceable commencing 7 days after the date set forth in this Consent Decree as the date by which ExxonMobil shall begin complying with such limit.

b. If ExxonMobil proposes to use an alternative monitoring plan to monitor an FCCU's compliance with an applicable emission limit during certain specified periods – as provided by Subparagraph 19.c, Paragraph 20 , 31, or 41, or Subparagraph 44.d – then ExxonMobil shall use its best efforts to submit a timely and complete application for approval of the proposed alternative monitoring plan, so that EPA can act on the application in a timely fashion. ExxonMobil shall use the proposed alternative monitoring plan to monitor compliance, if necessary, to meet the requirement to use an alternative monitoring plan while EPA is considering ExxonMobil's application (such as if there is a period of Malfunction while the application remains under EPA review). If EPA approves any such proposed alternative monitoring plan, ExxonMobil shall use the EPA-approved alternative monitoring plan to monitor compliance during the specified periods, as provided by Subparagraph 19.c, Paragraph 20 , 31, or 41, or Subparagraph 44.d. If EPA disapproves a proposed alternative monitoring plan, ExxonMobil shall submit to EPA for approval a substitute plan for compliance monitoring within ninety (90) days of receiving notice of the disapproval. Such substitute plan may include a revised alternative monitoring plan application, physical or operational changes to the equipment, or additional or different monitoring.

259. **<u>Startup, Shutdown, Malfunction</u>.** Notwithstanding the provisions of this Consent Decree regarding startup, shutdown, and Malfunction, this Consent Decree does not exempt ExxonMobil from the requirements of state laws and regulations or from the requirements of any permits or plan approvals issued to ExxonMobil, as these laws, regulations,

permits, and/or plan approvals may apply to startups, shutdowns, and Malfunctions at the Covered Refineries.

260. **Failure of Compliance.** The United States and the Applicable Co-Plaintiffs do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that ExxonMobil's complete compliance with the Consent Decree will result in future compliance with the provisions of the Clean Air Act and/or corresponding state or local laws. Notwithstanding the review or approval by the United States or the Applicable Co-Plaintiff, including their applicable state agencies, of any plans, reports, policies or procedures formulated pursuant to the Consent Decree, ExxonMobil shall remain solely responsible for compliance with the terms of the Consent Decree, all applicable permits, and all applicable federal, state and local laws and regulations, except as provided in Section XIV (Force Majeure).

261. **Service of Process.** ExxonMobil hereby agrees to accept service of process by mail with respect to all matters arising under or relating to the Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable local rules of this Court, including but not limited to, service of a summons. The persons identified by ExxonMobil at Paragraph 266 (Notice) are authorized to accept service of process with respect to all matters arising under or relating to the Consent Decree.

262. **Post-Lodging/Pre-Entry Obligations**. Obligations of ExxonMobil under this Consent Decree to perform duties scheduled to occur after the Date of Lodging of the Consent Decree, but prior to the Entry Date, shall be legally enforceable on and after the Entry Date. Liability for stipulated penalties, if applicable, shall accrue for violation of such obligations and payment of such stipulated penalties may be demanded by the United States and/or the Applicable Co-Plaintiffs as provided in this Consent Decree, provided that stipulated penalties

that may have accrued between the Date of Lodging of the Consent Decree and the Entry Date may not be collected unless and until this Consent Decree is entered by the Court.

263. **Costs**. The United States, the Co-Plaintiffs, and ExxonMobil shall each bear their own costs and attorneys' fees.

264. **Public Documents**. All information and documents submitted by ExxonMobil to EPA and the Applicable Co-Plaintiffs pursuant to this Consent Decree shall be subject to public inspection in accordance with the respective statutes and regulations that are applicable, unless subject to legal privileges or protection or identified and supported as business confidential in accordance with the respective state or federal statutes or regulations.

265. **Public Notice and Comment.** The Parties agree that the 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 this Court from the United States Department of Justice requesting entry of the Consent Decree. The United States reserves the right to withdraw or withhold its consent to the Consent Decree if public comments disclose facts or considerations indicating that the Consent Decree is inappropriate, improper, or inadequate. Further, the Parties acknowledge and agree that final approval by the State of Louisiana, through the LDEQ, and entry of this Consent Decree is subject to the requirements of La. Rev. Stat. Ann. § 30:2050.7, which provides for public notice of this Consent Decree in newspapers of general circulation and the official journals of parishes in which ExxonMobil facilities are located, an opportunity for public comment, consideration of any comments, and concurrence by the Louisiana Attorney General.

266. **Notice.** Unless otherwise provided herein, notifications to or communications between the Parties shall be deemed submitted on the date they are postmarked. Notifications and communications shall be sent by U.S. Mail, postage pre-paid, or private courier service,

except for notices under Section XIV (Force Majeure) and Section XV (Retention of Jurisdiction/Dispute Resolution) which shall be sent by overnight mail or by certified or registered mail, return receipt requested. Each report, study, notification or other communication of ExxonMobil shall be submitted as specified in this Consent Decree, with copies to EPA Headquarters, the applicable EPA Region, and the Applicable Co-Plaintiff. If the date on which a notification or other communication is due falls on a Saturday, Sunday or legal holiday, the deadline for such submission shall be enlarged to the next business day. Except as otherwise provided herein, all reports, notifications, certifications, or other communications required under this Consent Decree to be submitted or sent to the United States, EPA, the Applicable Co-Plaintiffs, and/or ExxonMobil 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. 90-5-2-1-07030

As to EPA:

EPA Headquarters:

U.S. Environmental Protection Agency
Director, Air Enforcement Division
Office of Regulatory Enforcement
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code 2242-A
Washington, DC 20460

with a hard copy to

Director, Air Enforcement Division
Office of Regulatory Enforcement
c/o Matrix Environmental & Geotechnical Services
215 Ridgedale Avenue
Florham Park, NJ 07932

and an electronic copy to
neichlin@matrixengineering.com
foley.patrick@epa.gov

EPA Region 5:

Air and Radiation Division
U.S. EPA, Region 5
77 West Jackson Blvd. (AE-17J)
Chicago, IL 60604
Attn: Compliance Tracker

and

Office of Regional Counsel
U.S. EPA, Region 5
77 West Jackson Blvd. (C-14J)
Chicago, IL 60604

EPA Region 6:

Chief
Air, Toxics, and Inspections Coordination Branch
Environmental Protection Agency, Region 6
1445 Ross Avenue
Dallas, Texas 75202-2733

EPA Region 8:

Air Program Coordinator
U.S. Environmental Protection Agency, Region 8
Montana Office
10 W. 15th St., Suite 3200
Helena, MT 59626

EPA Region 9:

Director
Air Division
Mail Code AIR-1
USEPA Region 9
75 Hawthorne Street
San Francisco, CA 94105

As to the State of Illinois:

Manager Compliance and Enforcement Section
Illinois Environmental Protection Agency
1021 North Grand Avenue, East
P.O. Box 19276
Springfield, IL 62794

and

Field Operations Section
Illinois Environmental Protection Agency
9511 West Harrison
Des Plaines, IL 60016

and

Maureen Wozniak
Assistant Counsel
Illinois Environmental Protection Agency
1021 North Grand Avenue, East
P.O. Box 19276
Springfield, IL 62794

As to the State of Louisiana:

Peggy M. Hatch
Administrator, Enforcement Division
Office of Environmental Compliance
Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312

As to the State of Montana:

Enforcement Division Administrator
Montana Department of Environmental Quality
P.O. Box 200901
Helena, MT 59620-0901

and

Bureau Chief
Air Resources Management Bureau
Montana Department of Environmental Quality
P.O. Box 200901
Helena, MT 59620-0901

As to ExxonMobil:

Assistant General Counsel, Litigation
Law Department
Exxon Mobil Corporation
800 Bell Street
ExxonMobil Building, Room 1503B
Houston, TX 77022
Tel. 713-656-3431
Fax 713-656-7719

and

Downstream Environment and Global Compliance Manager
Exxon Mobil Corporation
3225 Gallows Road
Room 8B 0233
Fairfax, VA 22037-0001

With a copy to each applicable refinery as shown below:

As to Baton Rouge:

Refinery Manager
ExxonMobil Baton Rouge Refinery
P.O. Box 551
Baton Rouge, LA 70821-0551

As to Baytown:

Refinery Manager
ExxonMobil Baytown Refinery
P.O. Box 3950
Baytown, TX 77522-3950

As to Beaumont:

Refinery Manager
ExxonMobil Beaumont Refinery
P.O. Box 3311
Beaumont, TX 77704

As to Billings:

Refinery Manager
ExxonMobil Billings Refinery
P.O. Box 1163
Billings, MT 59103

As to Joliet:

Refinery Manager
ExxonMobil Joliet Refinery
P.O. Box 874
Joliet, IL 60434

As to Torrance:

Refinery Manager
ExxonMobil Torrance Refinery
3700 W. 190th Street
Torrance, CA 90509-2929

Any Party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

267. **Approvals.** All EPA approvals or comments required under this Consent Decree shall be made in writing. All approvals by an Applicable Co-Plaintiff shall be sent from the offices identified in Paragraph 266 (Notice).

268. **<u>Paperwork Reduction Act</u>.** The United States has determined that 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 <u>et</u> <u>seq</u>.

269. **<u>Consent Decree Modifications</u>.** The Consent Decree contains the entire agreement of the Parties and shall not be modified by any prior oral or written agreement, representation or understanding. Prior drafts of the Consent Decree shall not be used in any action involving the interpretation or enforcement of the Consent Decree. Non-material modifications to this Consent Decree shall be in writing and shall be effective when signed by EPA and ExxonMobil. For the purpose of this Paragraph, non-material modifications include, but are not be limited to: (i) any modifications to the frequency of reporting obligations; and (ii) any modifications to schedules that do not extend the ultimate date for compliance with emissions limitations following the installation of control equipment or the completion of a catalyst additive program. The United States will file non-material modifications with the Court on a periodic basis. Material modifications to this Consent Decree shall be in writing, signed by EPA, the Applicable Co-Plaintiff, and ExxonMobil, and shall be effective upon approval by the Court.

XVIII. <u>TERMINATION</u>

270. **<u>Prerequisites to Termination</u>.** This Consent Decree shall be subject to termination upon motion by the United States, in consultation with the Applicable Co-Plaintiffs, or ExxonMobil (under the procedure identified in Paragraph 272). Prior to either party seeking termination, ExxonMobil shall have completed and satisfied all of the following requirements with respect to this Consent Decree:

i. installation of control technology systems as specified in this Consent Decree;

ii. compliance with all provisions contained in this Consent Decree, which compliance may be established for specific parts of the Consent Decree in accordance with Paragraph 271, below;

iii. payment of all penalties and other monetary obligations due under the terms of the Consent Decree; no penalties or other monetary obligations due hereunder can be outstanding or owed to the United States or the Applicable Co-Plaintiffs;

iv. completion of the SEPs and the payment for BEPs required by Section VIII;

v. application for and receipt of permits incorporating the surviving emission limits and standards established under Subsection V.Q; and

vi. operation for at least one year of each unit in compliance with the emission limits established herein, and certification of such compliance for each unit within the first six (6) month period progress report following the conclusion of the compliance period.

271. **Certification of Completion**.

a. Prior to moving for termination, ExxonMobil may certify completion for one or more of the Covered Refineries of one or more of the following Subsections of the Consent Decree, provided that all of the related requirements have been satisfied:

i. Subsections V.B - V.F, relating to FCCUs;

ii. Subsection V.G, relating to Combustion Units;

iii. Subsection V.H, relating to Heaters, Boilers and Other Fuel Gas Combustion Devices;

iv. Subsection V.I, relating to SRPs;

v. Subsections V.J - V.L, relating to Flaring;

vi. Subsections V.N, relating to Benzene Waste NESHAP;

vii. Subsection V.O, relating to LDAR;

viii. the requirements of Subsection V.P relating to certain other compliance requirements at the Billings Refinery;

ix. The requirements of Subsection V.P relating to certain other compliance requirements at the Joliet Refinery; and

x. Section VIII, relating to Environmentally Beneficial Projects.

b. Within 90 days after ExxonMobil concludes that any of the parts of the Consent Decree identified in this Paragraph 271 have been completed, ExxonMobil may submit a written report to the Parties listed in Paragraph 266 (Notice) describing the activities undertaken and certifying that the applicable Paragraphs have been completed in full satisfaction of the requirements of this Consent Decree, and that ExxonMobil is in substantial and material compliance with all of the other requirements of the Consent Decree. The report shall contain the following statement, signed by a responsible corporate official of ExxonMobil:

> To the best of my knowledge, after thorough investigation, I certify that the information contained in or accompanying this submission is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

c. Upon receipt of ExxonMobil's certification, EPA, after reasonable opportunity for review and comment by the Applicable Co-Plaintiffs, shall notify ExxonMobil whether the requirements set forth in the applicable Paragraphs have been completed in accordance with this Consent Decree. The parties recognize that ongoing obligations under such Paragraphs remain and necessarily continue (e.g., reporting, record keeping, training, auditing requirements), and that ExxonMobil's certification is that it is in current compliance with all such obligations.

i. If EPA concludes that the requirements have not been fully complied with, EPA shall notify ExxonMobil as to the activities that must be undertaken to complete the applicable Paragraphs of the Consent Decree. ExxonMobil shall perform all activities described in the notice, subject to its right to invoke the dispute resolution procedures set forth in Section XV (Dispute Resolution).

ii. If EPA concludes that the requirements of the applicable Paragraphs have been completed in accordance with this Consent Decree, EPA will so certify in writing to ExxonMobil. This certification shall constitute the certification of completion of the applicable Paragraphs for purposes of this Consent Decree.

d. Nothing in Subparagraph 271.c shall preclude the United States or an Applicable Co-Plaintiff 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 Paragraph 271. In addition, nothing in Subparagraph 271.c shall permit ExxonMobil to fail to implement any ongoing obligations under the Consent Decree regardless of whether a Certification of Completion has been issued with respect to Paragraph 271 of the Consent Decree.

272. **Termination Procedure.** At such time as ExxonMobil believes that it has satisfied the requirements for termination set forth in Paragraph 270, ExxonMobil shall certify such compliance and completion to the United States and the Applicable Co-Plaintiffs in writing as provided in Paragraph 266 (Notice). Unless, within 120 days of receipt of ExxonMobil's certification under this Paragraph, either the United States or the Applicable Co-Plaintiff objects in writing with specific reasons, ExxonMobil may move this Court for an order that this Consent Decree be terminated. If either the United States or the Applicable Co-Plaintiff objects to the certification by ExxonMobil under this Paragraph, then the matter shall be submitted to the Court for resolution under Section XV (Retention of Jurisdiction/Dispute Resolution) of this Consent Decree. In such case, ExxonMobil shall bear the burden of proving that this Consent Decree should be terminated.

273. Termination of this Consent Decree shall not terminate the obligations specified by Paragraph 145.

XIX. <u>SIGNATORIES</u>

274. Each of the undersigned representatives certifies that he or she is fully authorized to enter into the Consent Decree on behalf of such Parties, and to execute and to bind such Parties to the Consent Decree. This Consent Decree may be signed in counterparts.

Dated and entered this _______ day of __________, 2005

____
UNITED STATES DISTRICT JUDGE

THE UNDERSIGNED PARTY enters into this Consent Decree in:
United States v. Exxon Mobil Corporation and ExxonMobil Oil Corporation (N.D. Ill.)

FOR THE UNITED STATES OF AMERICA

Date: ____________________

____
KELLY A. JOHNSON
Acting Assistant Attorney General
Environment and Natural Resources Division
U.S. Department of Justice
Washington, DC 20530

Date: ____________________

____
RANDALL M. STONE
Trial Attorney
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611
Washington, DC 20044-7611

PATRICK J. FITZGERALD
United States Attorney

LINDA WAWZENSKI
Assistant United States Attorney
Northern District of Illinois
219 S. Dearborn Street – 5th Floor
Chicago, IL 60604

THE UNDERSIGNED PARTY enters into this Consent Decree in:
United States v. Exxon Mobil Corporation and ExxonMobil Oil Corporation (N.D. Ill.)

FOR THE U.S. ENVIRONMENTAL
PROTECTION AGENCY

Date: ____________________

____
GRANTA Y. NAKAYAMA
Assistant Administrator for
Enforcement and Compliance Assurance
United States Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

THE UNDERSIGNED PARTY enters into this Consent Decree in:
United States v. Exxon Mobil Corporation and ExxonMobil Oil Corporation (N.D. Ill.)

FOR THE PEOPLE OF
THE STATE OF ILLINOIS
ex rel. LISA MADIGAN, Attorney General
of the State of Illinois

MATTHEW J. DUNN, Chief
Environmental Enforcement/Asbestos Litigation
Division

Date: ____________________ ____________________________________

ROSEMARIE CAZEAU, Chief
Environmental Bureau
Assistant Attorney General
188 West Randolph St. – 20th Floor
Chicago, IL 60601

FOR THE ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

Date: ____________________ ____________________________________

ROBERT A. MESSINA
Chief Legal Counsel

THE UNDERSIGNED PARTY enters into this Consent Decree in:
United States v. Exxon Mobil Corporation and ExxonMobil Oil Corporation (N.D. Ill.)

FOR THE STATE OF LOUISIANA

CHARLES C. FOTI, JR.
Attorney General

Date: ____________________ ________________________________
Assistant Attorney General
Louisiana Department of Justice
P.O. Box 94005
Baton Rouge, LA 70804-9005

FOR THE LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Date: ____________________ ________________________________
HAROLD LEGGETT, Ph.D.
Assistant Secretary
Office of Environmental Compliance
Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4301

Date: ____________________ ________________________________
TED R. BROYLES, II
Attorney III
Office of the Secretary
Legal Affairs Division
Louisiana Department of Environmental Quality
P.O. Box 4302
Baton Rouge, LA 70821-4302

THE UNDERSIGNED PARTY enters into this Consent Decree in:
United States v. Exxon Mobil Corporation and ExxonMobil Oil Corporation (N.D. Ill.)

FOR THE STATE OF MONTANA

Date: ____________________

____
RICHARD OPPER
Director
Montana Department of Environmental Quality
P.O. Box 200901
Helena, MT 59620-0901

Date: ____________________

____
DAVID RUSOFF
Special Assistant Attorney General
Montana Department of Environmental Quality
P.O. Box 200901
Helena, MT 59620-0901

THE UNDERSIGNED PARTY enters into this Consent Decree in:
United States v. Exxon Mobil Corporation and ExxonMobil Oil Corporation (N.D. Ill.)

FOR DEFENDANT
EXXON MOBIL CORPORATION

Date: ____________________ ________________________________

Donald H. Daigle
Vice President Refining
ExxonMobil Refining & Supply Company
(a division of Exxon Mobil Corporation)
3225 Gallows Road
Fairfax, VA 22037

FOR DEFENDANT
EXXONMOBIL OIL CORPORATION

Date: ____________________ ________________________________

Ian F. Scoble
Attorney-in-Fact
3225 Gallows Road
Fairfax, VA 22037

Appendix A: Information on Combustion Units Greater Than 40 mmBtu/hr

A-1: Baytown Refinery

Unit	Source	Maximum Heat Input Capacity, mmBtu/hr (HHV)	2000/2001 NOx Emission Rate, lb/mmBtu (HHV)	Basis for NOx Factor	2000/2001 Average Annual Utilization Rate, mmBtu/hr (HHV)	2000/2001 Average NOx, TPY
BH-6	B-64	380	0.114	January 7, 1994 Stack Test	104	52
CLEU-1	B-2	132	0.111	August 25, 2000 Stack Test	50	24
CLEU-2	F-1	66	0.280	December 30, 1993 Stack Test	39	48
CLEU-2	F-2	86	0.136	April 14, 2000 Stack Test	60	36
CLEU-2	F-3	168	0.018	CEMS	80	6
DCU	F-601	140	0.060	Manufacturer's Specification in lb/MBtu; John Zink model PXMR-10. The Unit started up in Nov-01.	8	2
DCU	F-602	140	0.060	Manufacturer's Specification in lb/MBtu; John Zink model PXMR-10. The Unit started up in Nov-01.	8	2
FCCU-3	F-103	186	0.090	August 22, 2000 Stack Test	46	18
FCCU-3	F-105	142	0.200	June 26, 1998 Stack Test	100	88
FXK	F-301	110	0.067	Manufacturer's Specification in lb/MBtu; John Zink model PSMR-20M-FXG	65	19
GF-1	F-201	126	0.044	August 23, 2000 Stack Test	100	19
GF-1	F-227	120	0.060	August 24, 2000 Stack Test	96	25
HCU-1	F-701	195	0.107	August 21, 2000 Stack Test	130	61
HCU-1	F-810	85	0.084	August 21, 2000 Stack Test	32	12
HDU-1	F-701	75	0.160	December 6, 1993 Stack Test	29	20
HDU-1	F-702	75	0.200	December 6, 1993 Stack Test	45	39
HF-3	F-1	302	0.080	CEMS	189	66
HF-3	F-2	331	0.070	CEMS	130	40
HF-3	F-3	229	0.074	CEMS	94	30
HF-3	F-4	157	0.069	April 14, 2000 Stack Test	70	21
HF-3	F-7	85	0.140	TCEQ	26	16
HF-4	F-401	399	0.031	CEMS	276	37
HF-4	F-402	398	0.026	CEMS	167	19
HF-4	F-403	294	0.074	CEMS; NG ULNB installed Nov-01	129	42
HF-4	F-404/5	288	0.065	CEMS	132	38
HGU-1	F-101	386	0.127	CEMS	318	177
HGU-1	F-121	386	0.127	CEMS	7	4
HU-5A	F-501	89	0.180	January 18, 1994 Stack Test	40	32
HU-5B	F-551	53	0.190	January 18, 1994 Stack Test	21	17
HU-6A	F-101	47	0.120	January 18, 1994 Stack Test	32	17
HU-6B	F-201	82	0.133	January 19, 1994 Stack Test	38	22
KHF	F-901	72	0.065	Manufacturer's Specification in lb/MBtu; John Zink model PSMR-20	57	16
LEFU Col 14	F-804	83	0.080	March 23, 1994 Stack Test	0	0
LEFU Col 15	F-601	93	0.130	March 22, 1994 Stack Test	58	33
LEFU Col 15	F-602	93	0.140	March 22, 1994 Stack Test	56	34

LEFU Col 15	F-603	93	0.120	March 22, 1994 Stack Test	56	29
LEFU Col 16	F-506	57	0.100	March 22, 1994 Stack Test	8	4
LHF	F-926	45	0.101	January 12, 1994 Stack Test	29	13
LHU-2	F-3	45	0.140	TCEQ	13	8
LXU-1	B-5	180	0.050	January 9, 1992 Stack Test	110	24
LXU-2	B-1	72	0.110	January 4, 1994 Stack Test	24	12
LXU-2	B-2	195	0.270	January 4, 1994 Stack Test	127	150
LXU-2	B-4	195	0.175	September 6, 2000 Stack Test	114	87
NFU	F-902	70	0.150	December 21, 1993 Stack Test	26	17
NHF	F-701	135	0.087	September 8, 1995 Stack Test	47	18
PS-3	F-301	45	0.110	December 27, 1993 Stack Test	33	16
PS-3	F-302	45	0.170	December 28, 1993 Stack Test	30	22
PS-3	F-303	292	0.130	December 27, 1993 Stack Test; CEMS 3/20/00 through 12/31/01	209	119
PS-3	F-305	126	0.102	August 15, 2000 Stack Test	87	39
PS-7	F-701A	183	0.112	August 18, 2000 stack test for 2000 & 2001 through July 10; NG ULNB installed with new stack test July 11, 2001	101	50
PS-7	F-701B	184	0.136	August 18, 2000 Stack Test	103	61
PS-7	F-702A	151	0.091	August 16, 2000 Stack Test	83	33
PS-7	F-702B	140	0.079	August 17, 2000 Stack Test	79	27
PS-7	F-705	176	0.038	June 22, 1999 Stack Test; PEMS started January 1, 2001	133	22
PS-7	F-706	151	0.038	June 22, 1999 Stack Test; PEMS started January 1, 2001	114	19
PS-7	F-707	199	0.022	June 22, 1999 Stack Test; PEMS started January 1, 2001	185	18
PS-8	F-801	489	0.046	CEMS	397	80
PS-8	F-802	489	0.036	CEMS	399	63
PS-8	F-803	122	0.120	January 13, 1994 Stack Test	86	45
PS-8	F-804	131	0.060	January 12, 1994 Stack Test	86	23
RHC	F-301	80	0.048	November 8, 2000 Stack Test	38	8
SCU-2	F-703	43	0.040	Manufacturer's Specification (0.02 lb/MBtu); Callidus model CUB-10...using 0.04 lb/MBtu for emissions calculations	4	1
SFU	F-751	53	0.140	TCEQ	25	15
BH-6	GTG-35	289	0.142	December 1993 Stack Test	230	143
BH-6	GTG-36	289	0.227	December 1993 Stack Test	233	232
BH-6	GTG-37	289	0.170	May 1995 Stack Test	276	206
BH-6	GTG-38	618	0.072	CEMS	464	146
BH-7	GTG-41	397	0.143	October 1999 Stack Test	378	237
BH-7	GTG-42	397	0.142	October 1999 Stack Test	366	228
BH-7	GTG-43	397	0.142	October 1999 Stack Test	357	222
BH-7	GTG-44	397	0.145	October 1999 Stack Test	323	205
BH-7	GTG-45	618	0.050	CEMS	495	108
MEK	C-4VT	101	0.211	January 1994 Stack Test	100	92
TOTALS		14071				3976

A-2: Baton Rouge Refinery

Unit	Source	Maximum Heat Input Capacity, mmBtu/hr (HHV)	2000/2001 NOx Emission Rate, lb/mmBtu (HHV)	Basis for NOx Factor	2000/2001 Average Annual Utilization Rate, mmBtu/hr (HHV)	2000/2001 Average NOx, TPY
2 LEU	F- 501	227	0.077	January 28, 2002 Stack Test	150	51
4 LEU	F-1	49	0.111	Developed from Test Data from other furnaces in 1990	34	17
4 LEU-W	F-1	96	0.099	January 29, 2002 Stack Test	71	31
4 LEU-W	F-101	182	0.025	January 29, 2002 Stack Test	138	15
4 LEU-W	F-2	96	0.060	January 29, 2002 Stack Test	37	10
East Coker	F-1	266	0.057	January 30, 2002 Stack Test	234	58
Far East Coker	F-501A	158	0.049	January 30, 2002 Stack Test	133	29
Far East Coker	F-501B	158	0.236	November 2002 Test Data	126	130
Feed Prep	F-30	123	0.140	April 2002 Test Data	51	31
Feed Prep	F-31	200	0.031	April 2002 Test Data	171	23
HCLA	F-101	143	0.087	January 31, 2002 Test Data	40	15
HCN	F-201	57	0.085	Developed from Test Data from other furnaces in 1990	21	8
HCN	F-202	72	0.308	Developed from Test Data from other furnaces in 1990	49	66
HHLA-E	F-501	72	0.040	Manufacturer's Specification in lb/MBtu; Callidus model LE-CSG-10P	9	2
HHLA-S	F-201	55	0.071	Developed from Test Data from other furnaces in 1990	21	7
KDLA	F-425	92	0.090	April 2002 Test Data	50	20
KDLA	F-451	189	0.081	January 30, 2002 Stack Test	89	31
LELA-E	F-1	207	0.066	January 30, 2002 Stack Test	112	32
LELA-S	F-3	200	0.070	April 2002 Test Data	133	41
PCLA-2	F-2	333	0.167	1990 Test Data	291	213
PCLA-3	F-3	333	0.167	Developed from Test Data from other furnaces in 1990	295	216
PHLA-2	F-1	151	0.070	April 2002 Test Data	131	40
PHLA-2	F-3	117	0.065	January 29, 2002 Test Data	101	29
PHLA-2	F-4	184	0.052	April 2002 Test Data	111	25
PHLA-2	F-5	55	0.111	Developed from Test Data from other furnaces in 1990	10	5
PHLA-2	F-7	47	0.083	Developed from Test Data from other furnaces in 1990	26	9
PHLA-2	F-2	151	0.090	April 2002 Test Data	137	54
PSLA-10	F-1	290	0.052	January 31, 2002 Test Data	217	49
PSLA-10	F-101	394	0.032	February 7, 2002 Test Data	327	46
PSLA-10	F-102	142	0.037	January 31, 2002 Test Data	95	15
PSLA-10	F-2	177	0.036	January 31, 2002 Test Data	94	15
PSLA-7	F-1	229	0.224	May 23, 2002 Test Data	212	208
PSLA-7	F-2	130	0.120	January 28, 2002 Test Data	63	33
PSLA-8	F-1	180	0.179	April 2002 Test Data	165	129
PSLA-8	F-2	95	0.082	April 2002 Test Data	57	20

PSLA-9	F-1	290	0.041	January 31, 2002 Test Data	202	36
PSLA-9	F-2	130	0.034	January 31, 2002 Test Data	80	12
RHLA-1	F-700	110	0.157	Developed from Test Data from other furnaces in 1990	0	0
RHLA-2	F-600	76	0.157	Developed from Test Data from other furnaces in 1990	51	35
West Coker	F-101	264	0.060	January 31, 2002 Test Data	136	36
TOTAL		6520				1841

A-3: Beaumont Refinery

Unit	Source	Maximum Heat Input Capacity, mmBtu/hr (HHV)	2000/2001 NOx Emission Rate, lb/mmBtu (HHV)	2000 Basis for NOx Factor	2001 Basis for NOx Factor	2000/2001 Average Annual Utilization Rate, mmBtu/hr (HHV)	2000/2001 Average NOx, TPY
CHD-1 Charge	B1	155	0.132	January 31, 1994 Stack Test	August 29, 2001 Stack Test	62	36
CHD2 Charge	B1	96	0.096	November 16, 1992 Stack Test	November 16, 1992 Stack Test	19	8
CHD2 Reboiler	B2	69	0.096	November 16, 1992 Stack Test	November 16, 1992 Stack Test	37	16
Coker East	B101B	108	0.069	January 25, 1994 Stack Test	August 31, 2001 Stack Test	58	18
Coker Far West	BA3000	124	0.082	September 14, 1993 Stack Test	August 22, 2001 Stack Test	59	21
Coker Mid	B101A	108	0.075	September 21, 1993 Stack Test	August 23, 2001 Stack Test	63	20
Coker West	B101C	108	0.085	April 6, 1993 Stack Test	April 6, 1993 Stack Test	53	20
CUA Crude	B1A	253	0.129	December 20, 1993 Stack Test	1993 Stack Test through 6/27/01; CEMS 6/28/01 forward	194	110
CUA Crude	B1B	253	0.217	December 20, 1993 Stack Test	1993 Stack Test through 9/28/01; CEMS 9/29/01 forward	205	194
CUA Vacuum	B2	125	0.055	February 2, 1994 Stack Test	August 28, 2001 Stack Test	90	22
CUA Vacuum	B3	95	0.074	February 2, 1994 Stack Test	February 2, 1994 Stack Test	65	21
CUB Atmospheric	H3101	865	0.102	CEMS	CEMS	542	241
CUB Vacuum N	H2001	132	0.113	December 16, 1992 Stack Test	December 16, 1992 Stack Test	78	39
CUB Vacuum S	H3102	164	0.078	February 1, 1994 Stack Test	August 24, 2001 Stack Test	99	34
FCC Feed Preheater	4B2	336	0.089	Mobil Test Data	CEMS 1/1/01 forward	221	86
Furfural 2 Extract	BA1/BA2	61	0.064	February 2, 1994 Stack Test	February 2, 1994 Stack Test	42	12

HDC Splitter Reb	H3305	83	0.090	June 25, 1998 Stack Test	1998 Stack Test through 3/14/01; Manufacturer's Specification (0.045 #/MBtu, LHV) 3/15/01 forward; Callidus model LE-CSG-8W (outside) and LE-CSG-18W (inside)...using 0.05 lb/MBtu for emissions calculations.	51	20
HDC Stab Reb	H3304	216	0.074	June 26, 1998 Stack Test	CEMS 1/1/01 forward	142	46
Isom Pretreater	B1	85	0.074	December 16, 1993 Stack Test	December 16, 1993 Stack Test	61	20
Isom Stab. Reb	B2	90	0.110	December 16, 1993 Stack Test	December 16, 1993 Stack Test	58	28
Power Plant 2	Boiler 15	402	0.229	December 15, 1993 Stack Test	1993 Stack Test through 1/17/01; CEMS 1/18/01 forward	199	199
Power Plant 2	Boiler 16	402	0.232	December 15, 1993 Stack Test	1993 Stack Test through 1/17/01; CEMS 1/18/01 forward	220	224
Power Plant 2	Boiler 17	402	0.228	December 14, 1993 Stack Test	1993 Stack Test through 1/17/01; CEMS 1/18/01 forward	218	218
Power Plant 2	Boiler 18	402	0.227	December 15, 1993 Stack Test	1993 Stack Test through 1/17/01; CEMS 1/18/01 forward	231	229
Power Plant 2	Boiler 19	402	0.154	December 14, 1993 Stack Test	1993 Stack Test through 1/17/01; CEMS 1/18/01 forward	232	156
Power Plant 2	Boiler 22	844	0.130	May 24, 1979 Stack Test through 5/11/00; CEMS 5/12/00 forward	CEMS	540	242
Power Plant 3	Boiler 32	724	0.225	December 21, 1993 Stack Test	1993 Stack Test through 1/18/01; CEMS 1/19/01 forward	492	485
Power Plant 3	Boiler 33	713	0.198	December 21, 1993 Stack Test	1993 Stack Test through 1/18/01; CEMS 1/19/01 forward	454	393

Power Plant 3	Boiler 34	713	0.159	December 21, 1993 Stack Test	1993 Stack Test through 1/18/01; CEMS 1/19/01 forward	508	354
PtR3 Debut Reb	H3408	99	0.055	Manufacturer's Specification of 0.04 lb/MBtu (LHV); Callidus model LE-SCG-8WSP. State permitting authority required BACT of 0.06 lb/MBtu...using 0.055 lb/MBtu (HHV) for emissions calculations.		53	13
PtR3 Pretreater	H3401	101	0.115	June 28, 1989 Stack Test	June 28, 1989 Stack Test	53	27
PtR3 Reformer	H3403-6	660	0.073	CEMS	CEMS	307	99
PtR3 Stripper Reb	H3402	84	0.059	December 7, 1994 Stack Test	December 7, 1994 Stack Test	55	14
PtR4 Debut Reb	B7201	45	0.066	CEMS	CEMS	26	8
PtR4 Depent Reb	B7002	160	0.051	January 26, 1994 Stack Test	August 21, 2001 Stack Test	75	17
PtR4 Pretreater	B7001	132	0.062	January 26, 1994 Stack Test	August 30, 2001 Stack Test	67	18
PtR4 Reformer	B7101-7104	964	0.061	CEMS	CEMS	501	135
TOTALS		10773					3842

A-4: Billings Refinery

Unit	Source	Maximum Heat Input Capacity, mmBtu/hr (HHV)	2000/2001 NOx Emission Rate, lb/mmBtu (HHV)	Basis for NOx Factor	2000/2001 Average Annual Utilization Rate, mmBtu/hr (HHV)	2000/2001 Average NOx, TPY
BOHO	B-8	133	0.13	Oct-96 Version of FIRE Database, Table 1.4-1	10	6
Coker	KCOB	146	0.13	Oct-96 Version of FIRE Database, Table 1.4-1	126	72
Crude	F1/401	280	0.13	Oct-96 Version of FIRE Database, Table 1.4-1	228	130
H2PLT	F-551	130	0.13	Oct-96 Version of FIRE Database, Table 1.4-1	91	52
POFO	F-700	107	0.13	Oct-96 Version of FIRE Database, Table 1.4-1	62	35
TOTALS		796				294

A-5: Joliet Refinery

Unit	Source	Maximum Heat Input Capacity, mmBtu/hr (HHV)	2000/2001 NOx Emission Rate, lb/mmBtu (HHV)	Basis for NOx Factor	2000/2001 Average Annual Utilization Rate (Gas), mmBtu/hr (HHV)	2000/2001 Average Annual Utilization Rate (Oil), mmBtu/hr (HHV)	2000/2001 Average NOx, TPY
Alky	7-B-1	138	0.140 Gas / 0.408 Oil	FIRE Database, Version 5.0	71	13	63
Aux.Util. Boiler	55-B-100	340	0.082*	October 7, 1982 Stack Test	197	0	79
			* Burners replaced in Fall 2002 with CG ULNB; NOx factor = 0.07 lb/MBtu (Manufacturer's Specification)				
CHD Charge	3-B-1	158	0.140	FIRE Database, Version 5.0	62	0	39
CHD Reboiler	3-B-2	129	0.140	FIRE Database, Version 5.0	69	0	36
Coker	16-B-1A	183	0.110	Manufacturer's Specification (0.06 lb/MBtu); Callidus model LE-CFSG-3W...using 0.11 lb/Mbtu for emissions per state permit application	130	0	63
Coker	16-B-1B	183	0.110	Manufacturer's Specification (0.06 lb/MBtu); Callidus model LE-CFSG-3W...using 0.11 lb/Mbtu for emissions per state permit application	133	0	64
Crude Preheat	1B3/13B4	240	0.033	Manufacturer's Specification in lb/MBtu; Callidus model LE-CSG-8WSP	212	0	31
Crude Vac.	13-B-2	277	0.175 Gas / 0.391 Oil	Gas: April 24, 1992 Stack Test; Oil: FIRE Database, Version 5.0	156	19	152
Crude-Atm	1-B-1A	389	0.140 Gas / 0.391 Oil	FIRE Database, Version 5.0	220	12	319
Crude-Atm.	1-B-1B	389	0.140 Gas / 0.391 Oil	FIRE Database, Version 5.0	223	10	Included in 1-B-1A Stack
FCC Air Preheater	4-B-1	196	0.150		0	0	used only for startup
PreTreater Charge	17-B-1	112	0.140	FIRE Database, Version 5.0	40	0	24

PreTreater Reboiler	17-B-2	164	0.140	FIRE Database, Version 5.0	70	0	42
Reformer	2-B-3/4/5/6	680	0.080	Manufacturer's Specification in lb/Mbtu; John Zink model PSFFG-30M (2-B-3), PSFFG-45M (2-B-4&6) and PSFFG-60M (2-B-5)	336	0	118
Reformer	2B-7	78	0.140	FIRE Database, Version 5.0	31	0	19
Sat Gas	8-B-1	61	0.140	FIRE Database, Version 5.0	44	0	26
TOTALS		3717					1074

A-6: Torrance Refinery

Unit	Source	Maximum Heat Input Capacity, mmBtu/hr (HHV)	2000/2001 NOx Emission Rate, lb/mmBtu (HHV)	Basis for NOx Factor	2000/2001 Average Annual Utilization Rate, mmBtu/hr (HHV)	2000/2001 Average NOx, TPY
Cat Hyd - DSU	6F-2	64	0.015	CEMS	22	1
Crude	1F-1	457	0.012	CEMS	403	22
Crude	1F-2	161	0.012	CEMS	153	8
FCC Aux Boiler	2F-4	309	0.165	CEMS	195	142
FCC Feed Htrtr	25F-1A	60	0.005	CEMS	14	0.3
FCC Feed Htrtr	25F-2A	60	0.004	CEMS	16	0.2
FCC Feed Htrtr	25F-1B	60	0.007	CEMS	18	0.5
FCC Feed Hydrotreater	25F-2B	60	0.006	CEMS	35	1
FCCU Charge Heater	2F-2	108	0.046	CEMS	48	10
H2 2	24F-1	931	0.006	CEMS	567	15
Hydrogen Plant - GTG	24J-01	316	0.016	CEMS	277	19
H21	4F-1E/W	527	0.095	CEMS	351	142
Hydrocracker	3F-3	129	0.057	CEMS	96	24
Hydrocracker	3F-4	73	0.060	CEMS	63	17
N Coker	21F-6	67	0.060	CEMS	54	14
N Coker	21F-7	67	0.063	CEMS	54	15
N Coker	21F-8	74	0.056	CEMS	52	13
Pretreater / Reformer No1	20F-4	79	0.022	CEMS	51	5
Pretreater / RF No1	20F-1	94	0.175	CEMS	22	16
Reformer No 2	19F-1	288	0.008	CEMS	218	7
S Coker	22F-1	126	0.092	CEMS	92	37
S Coker	22F-2	91	0.092	CEMS	68	27
S Coker	22F-3	91	0.077	CEMS	61	21
Utilities	30F-1	340	0.008	CEMS	154	6
Utilities	30F-2	340	0.008	CEMS	136	5
Utilities	75F-1	291	0.098	CEMS	160	69
TOTALS		5263				637

Appendix B: PEMS Program Requirements

PREDICTIVE EMISSIONS MONITORING SYSTEMS FOR HEATERS <u>AND BOILERS WITH CAPACITIES BETWEEN 150 AND 100 mmBTU/HR</u>

A Predictive Emissions Monitoring Systems ("PEMS") is a mathematical model that predicts the gas concentration of NO_x in the stack based on a set of operating data. Consistent with the CEMS data frequency requirements of 40 C.F.R. Part 60, the PEMS shall calculate a pound per million BTU value at least once every 15 minutes, and all of the data produced in a calendar hour shall be averaged to produce a calendar hourly average value in pounds per million BTU.

The types of information needed for a PEMS are described below. The list of instruments and data sources shown below represent an ideal case. However at a minimum, each PEMS shall include continuous monitoring for at least items 3-5 below. ExxonMobil will identify and use existing instruments and refinery data sources to provide sufficient data for the development and implementation of the PEMS.

<u>Instrumentation:</u>

1. Absolute Humidity reading (one instrument per refinery, if available)

2. Fuel Density, Composition and/or specific gravity - On line readings (it may be possible if the fuel gas does not vary widely, that a grab sample and analysis may be substituted)

3. Fuel flow rate

4. Firebox temperature

5. Percent excess oxygen

6. Airflow to the firebox (if known or possibly estimated)

7. Process variable data - steam flow rate, temperature and pressure - process stream flow rate, temperature & pressure, etc.

<u>Computers & Software:</u>

Relevant data will be collected and stored electronically, using computers and software. The hardware and software specifications will be specified in the source-specific PEMS.

<u>Calibration and Setup:</u>

1. Data will be collected for a period of 7 to 10 days of all the data that is to be used to construct the mathematical model. The data will be collected over an operating

range that represents 80% to 100% of the normal operating range of the heater/boiler;

2. A "Validation" analysis shall be conducted to make sure the system is collecting data properly;

3. Stack Testing to develop the actual emissions data for comparison to the collected parameter data; and

4. Development of the mathematical models and installation of the model into the computer.

<u>The elements of a monitoring protocol for a PEMS will include:</u>

1. Applicability

    a. Identify source name, location, and emission unit number(s);

    b. Provide expected dates of monitor compliance demonstration testing.

2. Source Description

    a. Provide a simplified block flow diagram with parameter monitoring points and emission sampling points identified (e.g., sampling ports in the stack);

    b. Provide a discussion of process or equipment operations that are known to significantly affect emissions or monitoring procedures (e.g., batch operations, plant schedules, product changes).

3. Control Equipment Description

    a. Provide a simplified block flow diagram with parameter monitoring points and emission sampling points identified (e.g., sampling ports in the stack);

    b. List monitored operating parameters and normal operating ranges;

    c. Provide a discussion of operating procedures that are known to significantly affect emissions (e.g., catalytic bed replacement schedules).

4. Monitoring System Design

    a. Install, calibrate, operate, and maintain a continuous PEMS;

    b. Provide a general description of the software and hardware components of the PEMS, including manufacturer, type of computer, name(s) of software product(s), monitoring technique (e.g., method of emission correlation).

Manufacturer literature and other similar information shall also be submitted, as appropriate;

c. List all elements used in the PEMS to be measured (e.g., pollutant(s), other exhaust constituent(s) such as O_2 for correction purposes, process parameter(s), and/or emission control device parameter(s));

d. List all measurement or sampling locations (e.g., vent or stack location, process parameter measurement location, fuel sampling location, work stations);

e. Provide a simplified block flow diagram of the monitoring system overlaying process or control device diagram (could be included in Source Description and Control Equipment Description);

f. Provide a description of sensors and analytical devices (e.g., thermocouple for temperature, pressure diaphragm for flow rate);

g. Provide a description of the data acquisition and handling system operation including sample calculations (e.g., parameters to be recorded, frequency of measurement, data averaging time, reporting units, recording process);

h. Provide checklists, data sheets, and report format as necessary for compliance determination (e.g., forms for record keeping).

5. Support Testing and Data for Protocol Design

a. Provide a description of field and/or laboratory testing conducted in developing the correlation (e.g., measurement interference check, parameter/emission correlation test plan, instrument range calibrations);

b. Provide graphs showing the correlation, and supporting data (e.g., correlation test results, predicted versus measured plots, sensitivity plots, computer modeling development data).

6. Initial Verification Test Procedures

a. Perform an initial relative accuracy test (RA test) to verify the performance of the PEMS for the equipment's operating range. The PEMS must meet the relative accuracy requirement of the applicable Performance Specification in 40 C.F.R. Part 60, Appendix B. The test shall utilize the test methods of 40 C.F.R. Part 60, Appendix A;

b. Identify the most significant independently modifiable parameter affecting the emissions. Within the limits of safe unit operation, and typical of the anticipated range of operation, test the selected parameter for three RA test data sets at the low range, three at the normal operating range and three at the high operating range of that parameter, for a total of nine RA test data sets. Each RA test data set should be between 21 and 60 minutes in duration;

c. Maintain a log or sampling report for each required stack test listing the emission rate;

d. Demonstrate the ability of the PEMS to detect excessive sensor failure modes that would adversely affect PEMS emission determination. These failure modes include gross sensor failure or sensor drift;

e. Demonstrate the ability to detect sensor failures that would cause the PEMS emissions determination to drift significantly from the original PEMS value;

f. The PEMS may use calculated sensor values based upon the mathematical relationships established with the other sensors used in the PEMS. Establish and demonstrate the number and combination of calculated sensor values which would cause PEMS emission determination to drift significantly from the original PEMS value.

7. Quality Assurance Plan

a. Provide a list of the input parameters to the PEMS (e.g., transducers, sensors, gas chromatograph, periodic laboratory analysis), and a description of the sensor validation procedure (e.g., manual or automatic check);

b. Provide a description of routine control checks to be performed during operating periods (e.g., preventive maintenance schedule, daily manual or automatic sensor drift determinations, periodic instrument calibrations);

c. Provide minimum data availability requirements and procedures for supplying missing data (including specifications for equipment outages for QA/QC checks);

d. List corrective action triggers (e.g., response time deterioration limit on pressure sensor, use of statistical process control (SPC) determinations of problems, sensor validation alarms);

e. List trouble-shooting procedures and potential corrective actions;

f. Provide an inventory of replacement and repair supplies for the sensors;

g. Specify, for each input parameter to the PEMS, the drift criteria for excessive error (e.g., the drift limit of each input sensor that would cause the PEMS to exceed relative accuracy requirements);

h. Conduct a quarterly electronic data accuracy assessment tests of the PEMS;

i. Conduct semiannual RA tests of the PEMS. Annual RA tests may be conducted if the most recent RA test result is less than or equal to 7.5%. Identify the most significant independently modifiable parameter affecting the emissions. Within the limits of safe unit operation and typical of the anticipated range of operation, test the selected parameter for three RA test data pairs at the low range, three at the normal operating range, and three at the high operating range of that parameter for a total of nine RA test data sets. Each RA test data set should be between 21 and 60 minutes in duration.

8. PEMS Tuning

a. Perform tuning of the PEMS provided that the fundamental mathematical relationships in the PEMS model are not changed.

b. Perform tuning of the PEMS in case of sensor recalibration or sensor replacement provided that the fundamental mathematical relationships in the PEMS model are not changed.

Appendix C: NSPS Subpart J Compliance Schedule for Certain Heaters and Boilers

Refinery	Combustion Device	Compliance Date [1/]
Baton Rouge	PHLA-2-F-1 PHLA-2-F-2 PHLA-2-F-3 PHLA-2-F-4 PHLA-2-F-5 PHLA-2-F-6	December 31, 2008
Baton Rouge	FEED PREP F-30 FEED PREP F-31	December 31, 2008
Baton Rouge	4LEU-E F-1 4LEU-W F-1 4LEU-W F-2	December 31, 2008
Baton Rouge	LELA-E F-1 LELA-S F-4	December 31, 2008
Baton Rouge	KDLA- F-425 KDLA F-451	December 31, 2008
Baytown	LE Unit Heater F-601 LE Unit Heater F-804	Submit AMP six months after Entry Date for NSPS vent stream
Billings	Pipestill Heater F-1	December 31, 2008 [2/]

1/ As provided by Consent Decree Subparagraph 59.c, where this Appendix C refers to an AMP submittal date rather than a final compliance date, ExxonMobil will submit an AMP application for the listed device by the date specified, and the device shall become an affected facility on the date that ExxonMobil receives EPA's approval of the relevant AMP.

2/ Between the Entry Date and December 31, 2008, Billings Pipestill Heater F-1 shall comply with the emission limitation specified by 40 C.F.R. § 60.104(a)(1) at all times, except when SWS T-23 ammonia overhead gas is combusted in the unit as permitted by pertinent provisions of the Montana State Implementation Plan.

Appendix C: NSPS Subpart J Compliance Schedule for Certain Heaters and Boilers (continued)

Refinery	**Combustion Device**	**Compliance Date** [3/]
Beaumont	CHD 1 Heater B-1	Submit AMP six months after Entry Date for hydrogen vent stream
Beaumont	Continuous Regen Reformer PTR 3 Heater Box B3403 through H3406	Submit AMP six months after Entry Date for Reformer Regen lock hopper vents stream
Beaumont	Continuous Regen Reformer PTR 4 Heater Box B7101 through B7104	Submit AMP six months after Entry Date for Reformer Regen lock hopper vents stream
Beaumont	Crude A B-1A Heater	Submit AMP six months after Entry Date for South Benzene Recovery/Carbon Unit vent stream
Beaumont	Crude A Vacuum Heater B-2 and B-3	Re-route vacuum tower overhead gas to fuel gas treatment by no later than December 31, 2005
Joliet	Reformer Heaters 2B3 and 2B4	Submit AMP six months after Entry Date for Reformer regen lock hopper vent stream
Torrance	Reformer Heater 19F-1	Submit AMP two months after next regeneration cycle for Reformer regen vent stream, but no later than December 31, 2006
Torrance	Heaters 25F1-A and 25F1-B	Submit AMP six months after Entry Date for kerosene/LGO dryers stream or reroute stream by 12 months after Entry Date

[3/] As provided by Consent Decree Subparagraph 59.c, where this Appendix C refers to an AMP submittal date rather than a final compliance date, ExxonMobil will submit an AMP application for the listed device by the date specified, and the device shall become an affected facility on the date that ExxonMobil receives EPA's approval of the relevant AMP.

Appendix D: NSPS Subpart J Compliance Schedule for Certain Other Fuel Gas Combustion Devices

Refinery	Combustion Device	Compliance Date [4/]
Baton Rouge	MVR Combustor/Flare No. 1	AMP pending
Baton Rouge	MVR Combustor/Flare No. 2	AMP pending
Baytown	MVR Thermal Oxidizer VCU-440	Submit AMP six months after Entry Date
Baytown	MVR Thermal Oxidizer VCU-470	Submit AMP six months after Entry Date
Baytown	Thermal Oxidizer for Loading Racks 2 & 3	Submit AMP six months after Entry Date
Baytown	Caustic Oxidation Unit Incinerator	Submit AMP six months after Entry Date
Beaumont	MVR - John Zink Combustor	Submit AMP six months after Entry Date
Billings	FCCU CO Boiler	Treat or re-route SWS T-23 ammonia overhead gas by no later than December 31, 2008; Submit AMP six months after Entry Date for Unsaturated Light Ends Merox Vent stream (DSO Offgas stream)
Joliet	NBRU Thermal Vapor Incinerator - 38B-1	Shutdown, treat, or re-route stream by no later than December 31, 2008
Joliet	SBRU Thermal Vapor Incinerator - 38B-2	Shutdown, treat, or re-route stream by no later than December 31, 2008
Torrance	API Thermal Oxidizer 72F2	Submit AMP six months after Entry Date
Torrance	API Thermal Oxidizer 72F4	Submit AMP six months after Entry Date
Torrance	Resid Loading Rack Incinerator 50J-30	Submit AMP six months after Entry Date
Torrance	Sulfur Pit Vapor Incinerator 28F-11	Shutdown, treat, or re-route stream by July 1, 2009

4/ As provided by Consent Decree Subparagraph 59.c, where this Appendix D refers to an AMP submittal date rather than a final compliance date, ExxonMobil will submit an AMP application for the listed device by the date specified, and the device shall become an affected facility on the date that ExxonMobil receives EPA's approval of the relevant AMP.

Appendix E:

Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas

Refinery fuel gas streams/systems eligible for the Alternative Monitoring Plan (AMP) should be inherently low in H_2S content, and such H_2S content should be relatively stable. The refiner requesting an AMP should provide sufficient information to allow for a determination of appropriateness of the AMP for each gas stream/system requested. Such information should include, but need not be limited to:

- A description of the gas stream/system to be considered including submission of a portion of the appropriate piping diagrams indicating the boundaries of the gas stream/system, and the affected fuel gas combustion device(s) to be considered and an identification of the proposed sampling point for the alternative monitoring;

- A statement that there are no crossover or entry points for sour gas (high H_2S content) to be introduced into the gas stream/system. (This should be shown in the piping diagrams);

- An explanation of the conditions that ensures low amounts of sulfur in the gas stream (i.e., control equipment or product specifications) at all times;

- The supporting test results from sampling the requested gas stream/system using appropriate H_2S monitoring (i.e., detector tube monitoring following the Gas Processor Association's: Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision), at minimum:

  - for frequently operated gas streams/systems - two weeks of daily monitoring (14 samples);

  - for infrequently operated gas streams/systems, 7 samples shall be collected unless other additional information would support reduced sampling.

  Note: All samples are grab samples.

- A description of how the two weeks (or seven samples for infrequently operated gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the gas stream/system going to the affected fuel gas combustion device. (e.g., The two weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out, and, therefore, should be representative of typical operating conditions affecting H_2S content in the gas stream going to the loading rack flare);

- Identification of a representative process parameter that can function as an indicator of a stable and low H_2S concentration for each fuel gas stream/system, (e.g., review of gasoline sulfur content as an indicator of sulfur content in the vapors directed to a loading rack flare);

- Suggested process parameter limit for each stream/system, the rationale for the parameter limit and the schedule for the acquisition and review of the process parameter data. The refiner will collect the proposed process parameter data in conjunction with the testing of the fuel gas stream's stable and low H_2S concentration.

The following shall be used for measuring H_2S in fuel gas within these types of AMPs unless the refiner requests, in writing, approval of an alternative methodology:

- Conduct H_2S measurement using detector tubes ("length-of-stain tube" type measurement);

- Detector tube ranges 0-10/0-100 ppm (N =10/1) shall be used for routine testing; and

- Detector tube ranges 0-500 ppm shall be used for testing if measured concentration exceeds 100 ppm H_2S.

<u>Data Range and Variability Calculation and Acceptance Criteria</u>

For each step of the monitoring schedule, sample range and variability will be determined by calculating the average plus 3 standard deviations for that test data set.

- If the average plus 3 standard deviations for the test data set is less than 81 ppm H_2S, the sample range and variability are acceptable and the refiner can proceed to the next step of the monitoring schedule.

  Note: 81 ppm is one-half the maximum allowable fuel gas standard under NSPS Subpart J, and the Agency believes that using 81 ppm acceptance criteria provides a sufficient margin for ensuring that the emission limit is not exceeded under normal operating conditions.

- If the data shows an unacceptable range and variability at any step (the average plus 3 standard deviations is equal to or greater than 81 ppm H_2S), then move to Step 7. Agency approval is required to proceed to the next step if the average plus 3 standard deviations is between 81 ppm and 162 ppm H_2S. As an example, approval may be granted based on a review of the test data and any pertinent information which demonstrates that sample variability during the test period was due to unusual circumstances. Supplemental test data may be taken to demonstrate that process variability is within the plan requirements. Data may be removed from the variability calculations for cause after agency approval.

- For Steps 3 and 4, if the data shows an unacceptable range and variability (the average plus 3 standard deviations is equal to or greater than 81 ppm H_2S), the source will drop back to the previous step's monitoring schedule.

- If at any time, one detector tube sample value is equal to or greater than 81 ppm H_2S, then begin sampling as specified in Step 6. Note: Standard deviation cannot be calculated for a data set containing one point.

Monitoring Schedule for Approved AMPs

For gas streams which must meet product specifications for sulfur content, one time only detection tube sampling along with a certification that the gas stream is subject to product or pipeline specifications is sufficient for the AMP. If the gas stream composition changes (i.e., new gas sources are added), or if the gas stream will no longer be required to meet product or pipeline specifications, then the gas stream must be resubmitted for approval under the AMP.

The following are examples of streams needing one time only monitoring:

- Certified commercial grade natural gas;
- Certified commercial grade LPG;
- Certified commercial grade hydrogen;
- Gasoline vapors from a loading rack that only loads gasoline meeting a product specification for sulfur content.

For other gas streams, the H_2S content of each refinery fuel gas stream/system with an approved AMP shall be monitored per the following schedule:

Step 1:

The refiner will monitor the selected process parameter for each stream/system, according to the established process parameter monitoring or review schedule approved by the agency in the AMP, and at times when conducting H_2S detector tube sampling.

Step 2:

The refiner will conduct random detector tube sampling twice per week for each stream/system for a period of six months (52 samples). For fuel gas streams infrequently generated and combusted in affected fuel gas combustion devices (i.e., less frequent than bi-weekly), detector tube samples shall be taken each time the fuel gas stream is generated and combusted. A total of at least 24 samples shall be collected for infrequently generated gas streams. Monitor and record the selected process parameter in accordance with the established schedule, and at times when conducting H_2S testing. Move to Step 3 if the calculated range and variability of the data meets the established acceptance criteria. Submit test data (raw measurements plus calculated average and variability) to the agency quarterly.

Step 3:

The refiner will conduct random H_2S sampling once per quarter for a period of six quarters (6 samples) with a minimum of 1 month between samples. A minimum of 9 samples are required for infrequently generated and combusted fuel gas streams before proceeding to Step 4. Continue to monitor and record the selected process parameter in accordance with the established schedule, and at times when conducting H_2S testing. Move to Step 4 if the calculated range and variability of the data meets the established acceptance criteria. Submit test data (raw measurements plus calculated average and variability) to the agency quarterly.

Step 4:

The refiner will conduct random H_2S sampling twice per year for a period of two years (4 samples); sample randomly in the 1st and 3rd quarters with a minimum of 3 months between samples. Continue to monitor and record the selected process parameter in accordance with the established schedule, and at times when conducting H_2S testing. Move to Step 5 if the calculated range and variability of the data meets the established criteria. Submit test data (raw measurements plus calculated average and variability) to the agency semiannually.

Step 5:

The refiner will continue to conduct testing on semi-annual basis. Testing is to occur randomly once every semiannual period with a minimum of 3 months between samples. Continue to monitor and record the selected process parameter in accordance with the established schedule, and at times when conducting H_2S testing. If any one sample is equal to or greater than 81 ppm H_2S, then proceed to the sampling specified in Step 7. Note: Standard deviation cannot be calculated for a data set containing one point.

Step 6:

If, at any time, the selected process parameter data indicates a potential change in H_2S concentration, or a single detector tube sample value is equal to or greater than 81 ppm H_2S, then the fuel gas stream shall be sampled with detector tubes on a daily basis for 7 days (or for infrequently generated gas streams - 7 samples during the same period of an indicated change in H_2S concentration, or as otherwise approved by the agency). If the average detector tube result plus 3 standard deviations for those seven samples is less than 81 ppm H_2S, the date and value of change in the selected process parameter indicator and the sample results shall be included in the next quarterly report, and the refiner shall resume monitoring in accordance with the schedule of the current step. If the average plus 3 standard deviations for those seven samples is equal to or greater than 81 ppm H_2S, sampling shall follow the requirements of Step 7.

Step 7:

If sample detector tube data indicates a potential for the emission limit to be exceeded (the average plus 3 standard deviations is equal to or greater than 81 ppm H_2S), as determined in the Data Range and Variability Calculation and Acceptance Criteria or in Step 6, the refiner shall notify the agency of those results before the end of the next business day following the last sample day. The fuel gas stream shall subsequently be tested daily for a two week period (or 14 samples during the same event or as otherwise approved by the agency for infrequently generated gas streams). After the two week period is complete, sampling will continue once per week, until the agency approves a revised sampling schedule or makes a determination to withdraw approval of the gas stream/system from the AMP. Note: At any time, a detector tube value in excess of the 162 ppm limit is evidence that the emission standard has been exceeded.

General Provisions of Approved AMPs

Upon agency request, the refiner shall conduct a test audit for any gas stream with an approved AMP. The audit shall consist of daily detector tube samples collected over a one week period (7 samples). For fuel gas streams infrequently generated and combusted in affected fuel gas combustion devices, an audit shall consist of 3 consecutive sampling events. (e.g., Rail loading may occur once per month, an audit would consist of 3 consecutive loading events.) The United States Environmental Protection Agency, with due notice, reserves the right to withdraw approval of the AMP for any gas stream/system.

The source shall keep records of the H_2S detector tube test data and the representative process parameter data and fuel source for at least two years.

If a new fuel gas stream is introduced into a fuel gas stream with an approved AMP, the refiner shall again apply for an AMP and repeat Steps 1 - 5.

Example:

An AMP Application for a Hydrogen Plant PSA Off-Gas Stream Combusted Exclusively in the Hydrogen Plant Process Heater:

Process Description

Hydrogen production for the refinery by the steam methane reforming process. CO_2 is the primary impurity in the hydrogen produced; small amounts of CO and methane are also present. Unpurified hydrogen is passed over molecular sieve absorbent beds to remove these impurities. The off gas from regeneration of the absorbent beds is called PSA off-gas. It is sent to the hydrogen plant heater to recover heat and control CO emissions.

Piping Diagrams

Piping diagrams should be supplied to show monitoring location and to demonstrate that there is no potential for cross over or entry points for sour gas.

Basis for PSA Off-Gas Low H_2S Content

Since PSA off-gas is a byproduct of hydrogen purification, any H_2S in the PSA purge gas must come from the hydrogen unit feed. Levels of H_2S in the PSA gas are negligible because H_2S must be controlled to prevent deactivation of the unit's catalyst. H_2S is a permanent catalyst poison. The hydrogen unit has 2 scrubbers to remove H_2S poisoning. The scrubbers are operated in series. The lead scrubber must exhibit at least a 70% reduction in H_2S content. If not, the scrubber is taken off line and the absorbent is replaced. After the absorbent is replaced, the scrubber is placed on line as the second scrubber in series. This maximizes the amount of H_2S removal and assures maximum scrubbing potential when one scrubber is off line for absorbent replacement.

Process Parameter Monitoring and Suggested Process Parameter Limit

Operation of the scrubbers is checked on a monthly basis with detector tubes. The feed gas H_2S content is measured at the inlet and outlet of the lead scrubber. If natural gas is used as hydrogen plant feed; both readings are below the 1 ppm detection limit. If refinery fuel gas is the feed gas, 30 ppm to 40 ppm H_2S is normally detected at the inlet. A lead scrubber outlet reading of 10 -12 ppm H_2S would trigger absorbent replacement. The suggested process parameter limit is 20 ppm H_2S at the lead H_2S absorber outlet. Absorber outlet H_2S measurements will be taken in conjunction with the PSA gas measurements during Steps 2 and 3.

Appendix F: List of Existing Flaring Devices Operated by Covered Refineries [5/]

Baton Rouge Refinery

Flare 5
Flare 8
Flare 9
Flare 17*
Flare 19*
Flare 20
Flare 21
Flare 23
Flare 24

Baytown Refinery

Flare 3
Flare 4*
Flare 5
Flare 6*
Flare 11
Flare 14
Flare 15
Flare 16
Flare 17
Flare 18
Flare 19*
Flare 20
Flare 21
Flare 22*
Flare 25*
Flare 26*
Flare 27

Beaumont Refinery

High Pressure (HP) Flare
Low Pressure (LP) Flare
FCC Flare
CHD 1 Flare*
CHD 2 Flare*
Coker Flare
Flare 6
Flare 7
Flare 10

Billings Refinery

Main Flare*
Turnaround Flare*

Joliet Refinery

South Flare 49-B-305b*
East Flare 49-B-305a*

Torrance Refinery

Flare 55F-1
Flare 65F-3*
Flare 65F-4*
Ground Flare 65F-8*

[5/] Flaring Devices followed by an asterisk (*) currently are used as Acid Gas Flaring Devices or as dual-service Acid Gas/Hydrocarbon Flaring Devices. Flaring Devices that are not followed by an asterisk currently are used solely as Hydrocarbon Flaring Devices.

Appendix G: NSPS Subpart J Compliance Schedule for NSPS Flaring Devices Operated by Covered Refineries

Refinery	Flaring Device	Compliance Date [6]	Compliance Method
Baton Rouge	Flare 5	Entry Date	Subparagraph 73.a.i
Baton Rouge	Flare 8	Entry Date	Subparagraph 73.a.i
Baton Rouge	Flare 9	Entry Date	Subparagraph 73.a.i
Baton Rouge	Flare 17	Entry Date	Subparagraph 73.a.i
Baton Rouge	Flare 19	Entry Date	Subparagraph 73.a.i
Baton Rouge	Flare 20	Entry Date	Subparagraph 73.a.i
Baton Rouge	Flare 21	Entry Date	Subparagraph 73.a.ii
Baton Rouge	Flare 23	Entry Date	Subparagraph 73.a.i
Baton Rouge	Flare 24	Entry Date	Subparagraph 73.a.i
Baytown	Flare 3	Entry Date	Subparagraph 73.a.i
Baytown	Flare 4	Submit AMP six months after Entry Date for HF3 vent stream routed to flare downstream from flare gas recovery system All other streams routed to Flare 4, through flare gas recovery system	Subparagraph 73.a.iii Subparagraph 73.a.i
Baytown	Flare 5	Entry Date	Subparagraph 73.a.i
Baytown	Flare 6	Entry Date	Subparagraph 73.a.i
Baytown	Flare 11	Monitor with CEMS as required by 40 C.F.R. § 60.105(a)(3) or (a)(4) by no later than 12 months after Entry Date	Subparagraph 73.a.iv
Baytown	Flare 14	Monitor with CEMS as required by 40 C.F.R. § 60.105(a)(3) or (a)(4) by no later than 12 months after Entry Date	Subparagraph 73.a.iv
Baytown	Flare 15	Entry Date	Subparagraph 73.a.i
Baytown	Flare 16	Entry Date	Subparagraph 73.a.i

6/ As provided by Consent Decree Subparagraph 73.b, where this Appendix G refers to an AMP submittal date rather than a final compliance date, ExxonMobil will submit an AMP application for the listed device by the date specified, and the device shall become an affected facility on the date that ExxonMobil receives EPA's approval of the relevant AMP.

Appendix G: NSPS Subpart J Compliance Schedule for NSPS Flaring Devices Operated by Covered Refineries (continued)

Refinery	Flaring Device	Compliance Date	Compliance Method
Baytown	Flare 17	24 months after Entry Date (so that certain streams can be re-routed by that Compliance Date)	Subparagraph 73.a.i
Baytown	Flare 18	Entry Date	Subparagraph 73.a.i
Baytown	Flare 19	Entry Date for emergency service Submit AMP six months after entry for intermittent low mass sweet streams	Subparagraph 73.a.ii Subparagraph 73.a.iii
Baytown	Flare 20	24 months after Entry Date for streams other than HF4 stream (so that certain streams can be re-routed by that Compliance Date) Submit AMP six months after Entry Date for monitoring HF4 stream when Flare 17 is on turnaround	Subparagraph 73.a.i Subparagraph 73.a.iii
Baytown	Flare 21	Entry Date	Subparagraph 73.a.i
Baytown	Flare 22	Entry Date for emergency service Submit AMP six months after Entry Date for monitoring intermittent low mass sweet streams when Flare 19 is on turnaround	Subparagraph 73.a.ii Subparagraph 73.a.iii
Baytown	Flare 25	Entry Date for emergency service Submit AMP six months after Entry Date for monitoring intermittent refinery fuel gas streams and natural gas streams	Subparagraph 73.a.ii Subparagraph 73.a.iii
Baytown	Flare 26	Submit AMP six months after Entry Date for monitoring certain sweet streams and nitrogen-containing streams	Subparagraph 73.a.iii
Baytown	Flare 27	Monitor with CEMS as required by 40 C.F.R. § 60.105(a)(3) or (a)(4) by no later than 12 months after Entry Date	Subparagraph 73.a.iv
Beaumont	High Pressure (HP) Flare	42 months after Entry Date (so that flare gas recovery system upgrades can be completed by that Compliance Date)	Subparagraph 73.a.i
Beaumont	Low Pressure (LP) Flare	42 months after Entry Date (so that flare gas recovery system upgrades can be completed by that Compliance Date)	Subparagraph 73.a.i
Beaumont	FCC Flare	42 months after Entry Date (so that flare gas recovery system upgrades can be completed by that Compliance Date)	Subparagraph 73.a.i

Appendix G: **NSPS Subpart J Compliance Schedule for NSPS Flaring Devices Operated by Covered Refineries (continued)**

Refinery	Flaring Device	Compliance Date	Compliance Method
Beaumont	CHD 1 Flare	42 months after Entry Date	Subparagraph 73.a.i, 73.a.ii, or 73.a.iii
Beaumont	CHD 2 Flare	42 months after Entry Date	Subparagraph 73.a.i, 73.a.ii, or 73.a.iii
Beaumont	Coker Flare [7/]	42 months after Entry Date	Subparagraph 73.a.i, 73.a.ii, or 73.a.iii
Billings	Main Flare	48 months after Entry Date (so that flare gas recovery system upgrades can be completed by that Compliance Date)	Subparagraph 73.a.i
Billings	Turnaround Flare	48 months after Entry Date (so that flare gas recovery system upgrades can be completed by that Compliance Date)	Subparagraph 73.a.i
Torrance	Flare 55F-1	Submit AMP six months after Entry Date	Subparagraph 73.a.iii
Torrance	Flare 65F-3	Entry Date	Subparagraph 73.a.i
Torrance	Flare 65F-4	Entry Date	Subparagraph 73.a.i
Torrance	Enclosed Ground Flare 65F-8 [8/]	Entry Date	Subparagraph 73.a.i

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[7/] With respect to the Beaumont Refinery's CHD 1 Flare, CHD 2 Flare, and Coker Flare, by no later than 42 months after the Entry Date, ExxonMobil shall either: (i) complete flare gas recovery system upgrades to bring the particular flare into compliance with Subparagraph 73.a.i; or (ii) re-route streams as required to bring the particular flare into compliance with Subparagraph 73.a.ii or 73.a.iii. In the first Semi-Annual Report that is due under Section IX after that 42 month period, ExxonMobil shall identify and certify compliance with a specific compliance method (i.e., either Subparagraph 73.a.i, 73.a.ii, or 73.a.iii) for each of those three Beaumont Refinery flares.

[8/] Enclosed Ground Flare 65F-8 is an enclosed combustion device that: (i) is not subject to the velocity test requirement referenced in Subparagraph 75.b.(2) of this Consent Decree; and (ii) is subject to the requirements imposed by SCAQMD Rule 1118 and 40 C.F.R. §§ 60.482-10 and 60.486(d).

Appendix G: NSPS Subpart J Compliance Schedule for NSPS Flaring Devices Operated by Covered Refineries (continued)

Identification of Particular Low Volume/Low Pressure Streams to be Routinely Combusted in Certain Baytown Refinery Flaring Devices

1. Low Volume/Low Pressure Streams to be Routinely Combusted in Baytown Flare 11 and/or Baytown Flare 14

   a. Hydrocracker Unit 1 (HCU-1)
      - S-702 (C-708 suction knock out drum) drain
      - D-713 (C-708 1st stage discharge knock-out drum) drain
      - D-714 (C-708 2nd stage discharge knock-out drum) drain
      - D-770 (C-770 1st stage suction knock-out drum) drain
      - D-771 (C-770 2nd stage suction knock-out drum) drain
      - D-772 (C-770 3rd stage suction knock-out drum) drain
      - D-780 (C-780 1st stage suction knock-out drum) drain
      - D-781 (C-780 2nd stage suction knock-out drum) drain
      - D-782 (C-780 3rd stage suction knock-out drum) drain D-780
      - Low-point piping seal pot drains from C-770 & C-780

   b. FCCU 3
      - C-302 (FCCU 3 wet gas compressor) seal oil liquid collection pot drain
      - C-303 (FCCU 3 wet gas compressor) seal oil liquid collection pot drain

   c. Hydrofining Unit 9 (HU-9)
      - D-390 (DCU flare knock-out drum) overhead vent
      - C-361 / 362 (hydrogen recycle and make-up compressors) buffer gas (N_2) vent and drains off compressor lube pots [through D-390]
      - RGB / LBG fuel gas knock-out drum liquid drain [through D-390]

2. Low Volume/Low Pressure Streams to be Routinely Combusted in Baytown Flare 27

   a. DCU
      - D-617 (residual flow from DCU flare knock-out drum)
      - D-612 vent (DCU blowdown settling drum)
      - 2 - C-601 suction lines condensible drains (during winter months)

If ExxonMobil identifies any other low volume/low pressure stream that is routinely combusted in Baytown Flare 11, Flare 14, or Flare 27, EPA may approve addition of that stream to this Appendix through a non-material modification under Consent Decree Paragraph 269, so long as the other conditions of Subparagraph 73.a.iv are met.

Appendix H: Data Relevant to Billings FCCU Baseline Emissions, Trials, Demonstrations, and Final Limits

As required by Consent Decree Paragraph 30, ExxonMobil shall submit the following categories of Billings FCCU data, on a daily or daily average basis as measured directly (where available) or as calculated (where necessary):

a. Regenerator bed, dilute phase, cyclone, and flue gas temperatures;

b. Coke burn rate in pounds per hour;

c. FCCU feed rate in barrels per day;

d. FCCU feed API gravity;

e. FCCU feed sulfur and basic nitrogen (where available) content as a weight %;

f. Estimated percentage, and where available, actual percentage of each type of FCCU feed component (i.e. atmospheric gas oil, vacuum gas oil, atmospheric tower bottoms, vacuum tower bottoms, etc.);

g. CO boiler firing rate and fuel type, if applicable;

h. CO boiler combustion temperature, if applicable;

i. Total Catalyst addition and catalyst circulation rates;

j. Conventional combustion promoter addition rates;

k. Hourly and daily volume percent oxygen in the regenerator flue gas and at the point of CEMs measurement;

l. Hourly and daily SO_2, NOx, and CO mass emission rates in pounds per hour, tons per year, and concentrations in ppmvd at 0% oxygen; and

m. Upon request by EPA, any additional, reasonably available data that EPA determines it needs to evaluate .

Appendix I: Additional Claims Concerning the Billings Refinery Referenced in Consent Decree Subparagraph 252.b

As provided by Consent Decree Subparagraph 252.b, entry of the Consent Decree shall resolve all civil liability of ExxonMobil to the United States and the Applicable Co-Plaintiff for the following alleged past violations of the CWA and RCRA (including the regulations implementing the CWA and RCRA) identified during June 2002 and/or July 2002 EPA inspections of the Billings Refinery:

<u>Alleged CWA Violations</u>

A. Alleged past violations of NPDES Permit MT0000477, Parts I.C.1.a and I.C.3 based on the acute toxicity of samples collected from outfall 001 on December 4, 2001, December 25, 2001, January 31, 2002, February 26, 2002, March 19, 2002, April 23, 2002, May 28, 2002, and June 12, 2002;

B. Alleged past violations of NPDES Permit MT0000477, Part I.C.1. Outfall 002: Non-Contact Cooling Water based on discharges causing visible oil sheens at outfall 002 during November 2000, November 2001, February 2002 and March 2002;

C. Alleged past violations of the General Permit for Stormwater Discharges Associated with Industrial Activity MTR 000000 (Authorization 000104) based on: (i) the failure of the Billings Refinery Storm Water Pollution Prevention Plan ("SWPPP") to identify certain potential sources of pollution to storm water discharges associated with the scrap metal yard located in the South Refinery Drainage Area; and (ii) the SWPPP's failure to provide an up-to date identification of the individual responsible for implementing the SWPPP.

D. Alleged past violations of 40 C.F.R. § 112.5(a) based on failure to incorporate a December 29, 1999 amendment to the Billings Refinery's Spill Prevention Control and Countermeasure Plan ("SPCC Plan") into the February 28, 2000 version of the Refinery's SPCC Plan.

E. Alleged past CWA violations concerning management of materials in Tank 350 (identified by EPA during its July 2002 inspection).

<u>Alleged RCRA Violations</u>

F. Alleged past violations of RCRA requirements based on storage of the following uncharacterized wastes in the scrap yard and/or lay down area at the Billings Refinery: heat exchanger bundles containing possible heat exchanger bundle cleaning sludge, welding rods, discarded aerosol cans, discarded insulation, and refrigeration and air conditioning equipment.

G. Alleged past violations of RCRA requirements based on application of waste at the Billings Refinery's Land Treatment Unit during periods of high winds.

Appendix J: Table of Alleged CWA Violations at the Joliet Refinery Referenced in Consent Decree Subparagraph 252.c.(1)

Month and Year	Outfall No.	Parameter and Other Details
1/1996	003	total organic carbon (daily maximum mg/l)
2/1996	003	total organic carbon (daily maximum mg/l)
3/1996	001	biological oxygen demand (daily maximum mg/l - 4 days during month)
3/1996	001	total suspended solids (daily maximum mg/l - 2 days during month)
4/1996	001	biological oxygen demand (daily maximum mg/l)
4/1996	001	ammonia (daily maximum mg/l)
4/1996	003	total organic carbon (daily maximum mg/l)
6/1996	003	total organic carbon (daily maximum mg/l)
7/1996	003	total organic carbon (daily maximum mg/l)
9/1996	001	total suspended solids (monthly average mg/l)
9/1996	001	total suspended solids (daily maximum mg/l)
5/1997	001	total suspended solids (daily maximum mg/l)
5/1997	001	ammonia (daily maximum mg/l)
12/1997	002	total organic carbon (daily maximum mg/l)
6/1998	001, 002, 003	total residual chlorine (daily maximum mg/l)
12/1998	003	total organic carbon (daily maximum mg/l)
1/1999	001	total suspended solids (monthly average lb/day)
1/1999	001	total suspended solids (daily maximum mg/l)
6/1999	001	total suspended solids (daily maximum mg/l)
6/1999	001	total suspended solids (daily maximum lb/day)
6/1999	--	oil sheen on river
7/1999	002	total organic carbon (daily maximum mg/l)
8/1999	002	total organic carbon (daily maximum mg/l)
8/1999	003	total organic carbon (daily maximum mg/l)
9/1999	001	total suspended solids (daily maximum mg/l)
9/1999	001	total suspended solids (monthly average lb/day)
5/2000	002	total organic carbon (daily maximum mg/l)
6/2000	005	unauthorized discharge of 2 gallons of oil (Special Condition 9)
10/2000	001, 002, 003	total residual chlorine (daily maximum mg/l)
11/2000	001	total suspended solids (daily maximum mg/l)
7/2001	004	total organic carbon (daily maximum mg/l)

Appendix J: Table of Alleged CWA Violations at the Joliet Refinery Referenced in Consent Decree Subparagraph 252.c.(1) (continued)

Month and Year	Outfall No.	Parameter and Other Details
10/2001	002	total organic carbon (daily maximum mg/l)
10/2001	008	unauthorized discharge of 2 gallons of oil (Special Condition 9)
10/2001	–	oil sheen on river
11/2001	002	total organic carbon (daily maximum mg/l)
1/2002	001, 002, 003	total residual chlorine (daily maximum mg/l)
5/2002	001, 002, 003	total residual chlorine (daily maximum mg/l)
8/2002	001, 002, 003	total residual chlorine (daily maximum mg/l)
9/2003	–	chromium
10/2002	001	ammonia (daily maximum mg/l)
11/2002	001	ammonia (daily maximum mg/l - 4 days during month)
11/2002	005	oil and grease (daily maximum mg/l)
12/2002	001	ammonia (daily maximum mg/l - 7 days during month)
3/2003	003	total organic carbon (daily maximum mg/l)
5/2003	003	total organic carbon (daily maximum mg/l)
6/2003	004	oil and grease (daily maximum mg/l)
4/2004	001	ammonia (daily maximum mg/l - 3 days during month)
5/2004	008	oil and grease (daily maximum mg/l)
5/2004	001	ammonia (daily maximum mg/l - 2 days during month)
6/2004	001	ammonia (daily maximum mg/l)
6/2004	003	pH (daily maximum SU)
8/2004	008	total organic carbon (daily maximum mg/l)
8/2004	001	pH (daily maximum SU)
11/2004	001	ammonia (daily maximum mg/l)
12/2004	001	ammonia (daily maximum mg/l)
1/2005	003	total organic carbon (daily maximum mg/l - 2 days during month)

Appendix K: Table of Alleged CERCLA Section 103 and EPCRA Section 304 Reporting Violations at the Joliet Refinery Referenced in Consent Decree Subparagraph 252.c.(1)

Date of Chemical Release	Chemical
3/18/2005	nitrogen oxides
1/14/2005	sulfur dioxide and nitrogen oxide
5/14/2004	nitrogen oxides, nitrogen dioxide, hydrogen sulfide and sulfur dioxide
11/2/2003	hydrogen sulfide and sulfur dioxide
10/7/2003	nitrogen oxides and sulfur dioxide
10/4/2003	nitrogen oxides
10/24/2002	nitrogen oxides
9/5/2002	nitrogen oxides
8/24/2002	nitrogen oxides and sulfur dioxide
6/1/2002	nitrogen dioxide, nitrogen oxides and sulfur dioxide
4/6/2002	nitrogen oxides
3/4/2002	nitrogen oxides and sulfur dioxide
2/24/2002	nitrogen dioxide and sulfur dioxide
9/27/1999	benzene
3/29/1999	nitrogen dioxide and/or nitrogen oxides
2/20/1999	hydrogen sulfide
2/5/1999	benzene
1/5/1999	nitrogen oxides
5/23/1998	nitrogen oxides
5/5/98	nitrogen oxides
2/21/1997	hydrogen sulfide
3/17/1996	nitrogen oxides

Appendix L: Additional Claims Concerning the Joliet Refinery Referenced in Consent Decree Subparagraph 252.c.(2)

As provided by Consent Decree Subparagraph 252.c.(2), entry of the Consent Decree shall resolve all civil liability of ExxonMobil to the Applicable Co-Plaintiff for the following alleged past violations of the Illinois Environmental Protection Act (the "IEP Act"), the facility's Clean Air Act Permit Program Permit No. 95120304 (the "CAAPP Permit"), and the Clean Air Act (including the regulations implementing the Clean Air Act) at the Joliet Refinery:

A. All alleged past violations of the IEP Act, Illinois Pollution Control Board Regulations at 35 Ill. Adm. Code Subtitle B, 40 C.F.R. Parts 60 and 63, the CAAPP Permit, and the Clean Air Act specified in IEPA Violation Notice A-2003-00205, dated August 22, 2003;

B. All alleged past violations of the IEP Act, Illinois Pollution Control Board Regulations at 35 Ill. Adm. Code Subtitle B, 40 C.F.R. Parts 60 and 63, the CAAPP Permit, and the Clean Air Act included in IEPA Violation Notice A-2004-00073, dated February 24, 2004;

C. All of the following alleged past violations of the IEP Act, Illinois Pollution Control Board Regulations at 35 Ill. Adm. Code Subtitle B, the CAAPP Permit, and the Clean Air Act associated with a May 15-16, 2004 shutdown event/release event at the Joliet Refinery and a May 17, 2004 follow-up inspection by IEPA:

(1) Alleged violation of Section 9(a) of the IEP Act and 35 Ill. Adm. Code 201.141 based on the release of hydrogen sulfide into the atmosphere on May 15-16, 2004;

(2) Alleged violation of Sections 9.1(d) and 39.5(6)(a) of the IEP Act, 40 C.F.R. § 63.6(e)(1)(i), and CAAPP Permit Condition 9.2.3 based on failure to operate the Joliet Refinery's Saturated Gas Plant and associated equipment in a manner consistent with good air pollution control practices on May 15-16, 2004;

(3) Alleged violation of Section 9.1(d) of the IEP Act and 40 C.F.R. § 63.641 based on the routing of material with a vapor pressure greater than 11.1 psia to a Group I storage vessel (consisting of Tanks 204, 205, and 421) not equipped with a closed vent system and control device on May 15-16, 2004;

(4) Alleged violation of Section 39.5(6)(a) of the IEP Act and CAAPP Permit Condition 5.6.5(b) based on failure to provide copies of data, shift logs, and emissions standards to IPA as requested during the May 17, 2004 inspection;

(5) Alleged violation of Section 9.1(d) of the IEP Act and 40 C.F.R. § 63.10(d)(5)(ii) based on failure to report actions taken on May 15-16, 2004 that were inconsistent with the facility's startup, shutdown, and malfunction plan;

(6) Alleged violations of Sections 9(a) and 39.5(6)(a) of the IEP Act, 35 Ill. Adm. Code 218.143, 40 C.F.R. § 60.18(c), and CAAPP Permit Condition 5.2.2(c) based on emission of VOM into the atmosphere from a flare on May 15, 2004 in a manner that was inconsistent with good air pollution control practices; and

(7) Alleged violation of Sections 9(a) and 39.5(6)(a) of the IEP Act, 35 Ill. Adm. Code 218.144, and CAAPP Permit Condition 5.2.2(f) based on the uncontrolled emission of VOM to the atmosphere, and the failure to route material with a vapor pressure of 1.5 psia or greater to a flare, the refinery fuel gas system, or other control equipment on May 15-16, 2004.

Appendix M: Additional Claims Concerning the Baton Rouge Refinery Referenced in Consent Decree Subparagraph 252.d

As provided by Consent Decree Subparagraph 252.d, entry of the Consent Decree shall resolve all civil liability of ExxonMobil to the Applicable Co-Plaintiff for all alleged past violations identified in each LDEQ Consolidated Compliance Order and Notice of Potential Penalty ("CONOPP") or LDEQ Administrative Order listed below:

A. CONOPP No. AE-CN-01-0254, issued October 16, 2001, for alleged unpermitted H_2S and SO_2 emissions from sulfur pit relief stacks at the sulfur recovery unit.

B. CONOPP No. MM-CN-01-0027, issued October 18, 2002, for alleged violations identified during the April-May 2001 multimedia inspection and subsequent file review.

C. CONOPP No. AE-CN-02-0233A, issued November 22, 2004, for alleged violations identified during the June 12-15, 2002 inspection and subsequent file review.

D. Administrative Order AE-AO-02-0255.

E. The alleged violations set forth in CONOPP No. AE-CN-03-0313, except for the alleged violations described in Section V (comprising Subsections V.A through V.G) of the Findings of Fact in that CONOPP.

Appendix N: Schedule for Use of CEMS at ExxonMobil's FCCUs

FCCU	**NOx CEMS**	**SO_2 CEMS**	**CO CEMS**	**O_2 CEMS**
Baton Rouge PCLA 2/3	Entry Date	Entry Date	Not required by Consent Decree	Entry Date
Baytown FCCU 2	Entry Date	Entry Date	Entry Date	Entry Date
Baytown FCCU 3	Entry Date	Entry Date	Entry Date	Entry Date
Beaumont FCCU	Entry Date	Entry Date	Entry Date	Entry Date
Billings FCCU	December 31, 2008	18 months after Entry Date	18 months after Entry Date	18 months after Entry Date
Joliet FCCU	18 months after Entry Date	18 months after Entry Date	18 months after Entry Date	18 months after Entry Date
Torrance FCCU	Entry Date	Entry Date	Entry Date	Entry Date

Appendix O: Summary of the Understanding Between LDEQ and the Louisiana Wildlife and Fisheries Foundation Relating to ExxonMobil's Payment for Beneficial Environmental Projects Under Consent Decree Paragraph 159

LDEQ and the Louisiana Wildlife and Fisheries Foundation (the "Foundation") have agreed that the amount payable by ExxonMobil under Consent Decree Paragraph 159 will be used exclusively for the acquisition or acquisitions of coastal lands which are: (a) important as fish and wildlife habitat, or (b) important to the enhancement of the state's coastal restoration effort, or both. Expenditures by the Foundation shall be limited to the purchase price of the land; reasonable and appropriate expenses which are necessary for the purchase, such as costs of appraisal and survey and reasonable closing costs; and the reasonable and necessary or prudent costs associated with restoration or nourishment of the lands. The Foundation will select the lands to be purchased based upon the recommendations of the Secretary of the Louisiana Department of Wildlife and Fisheries.

The Foundation is a non-profit, public charitable foundation, tax exempt under Section 501(c) (3) of the Internal Revenue Code. It was chartered in 1995, and its sole mission is to support the mission and programs of the Louisiana Department of Wildlife and Fisheries (the "Department") and the Louisiana Wildlife and Fisheries Commission (the "Commission") including promotion, development, expansion and improvement of the facilities of the Department and Commission. Toward that end, the Foundation exists to encourage public conservation and enjoyment of wildlife and fish resources, and to increase the agencies' usefulness to the citizens to the state of Louisiana. The Foundation provides a means for individuals and corporations to become partners with the Department and the Commission in the conservation of Louisiana's fish and wildlife resources, and has spearheaded a multitude of projects including cooperative endeavors with state and federal agencies and the private sector for fish and wildlife enhancement.

Once acquisition of the above referenced lands has been accomplished, the Foundation will execute an act (or acts) of donation(s) of said lands to the Department and the Commission. The Department and Commission will then establish the lands as a wildlife management area, wildlife refuge or other natural area; or will enter into cooperative endeavors with other state agencies for the protection, management and conservation of the said lands consistent with the above stated purposes.

Appendix P: Joliet Wastewater Treatment Plant Area Program

1. Summary. As required by Consent Decree Paragraph 134, ExxonMobil shall implement the Joliet Wastewater Treatment Plant Area Program ("WWTP Area Program") as described in detail in this Appendix P. The WWTP Area Program requires data collection and other actions in the general area of the Joliet Refinery encompassing the wastewater treatment plant, the Stormwater Diversion Basin ("SWDB"), the Equalization Biological Treatment Unit ("EBTU"), the Diversion Box, Inlet Structure, Outlet Box, and other related points (referred to herein as the "WWTP Area") depicted on attached Figure P-1.[9] Generally, the WWTP Area Program will include the following elements: flow monitoring, wastewater sampling (and subsequent analysis) at specific locations, precipitation monitoring, snowmelt monitoring, sludge characterization and removal, confirmation of proper aggressive biological treatment in the EBTU, groundwater and soil characterization, data reporting, and to the extent necessary based on data collected, measures to bring the WWTP Area into full compliance with applicable legal requirements. Certain monitoring and reporting on NPDES Permit compliance at the Joliet Refinery also is required.

2. The WWTP Area Wastewater Monitoring Plan. Within 90 days of the Entry Date, ExxonMobil shall submit to EPA for review and approval a WWTP Area Wastewater Monitoring Plan designed to identify certain properties of the water entering the EBTU and SWDB, and to provide other documentation as described in the sections below. The WWTP Area Wastewater Monitoring Plan shall specify a 12-month period ("Monitoring Period") during which wastewater shall be collected and analyzed as described below at the following locations generally identified on Figure P-1: (1) the SWDB at location 4c; (2) Stream 3 prior to mixing with Stream 6 (unless ExxonMobil takes the actions set out in Subparagraph 2.c.iv of this Appendix); and (3) Stream 6 near the entrance to the EBTU. The WWTP Area Wastewater Monitoring Plan shall include a reasonable time period between the date of EPA approval of the WWTP Area Wastewater Monitoring Plan and commencement of the Monitoring Period (such time period not to exceed six (6) months) to allow for the installation and completion of testing of all equipment necessary to perform the required monitoring programs. The parties will attempt to identify a commercially available autosampler for use in this program prior to the Date of Lodging. If the parties cannot find a commercially available autosampler acceptable to both EPA and ExxonMobil by that date, then ExxonMobil shall be allowed to take samples manually.

a. SWDB, Stream 4c.

i. SWDB Flow Monitoring. The WWTP Area Wastewater Monitoring Plan shall include a protocol for measuring wastewater flow through the Inlet Structure into

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[9] Based on information and belief, formed after reasonable inquiry, ExxonMobil certifies by signing this Decree that the WWTP flows are as depicted on Figure P-1, and agrees that variances from Figure P-1 may, at EPA's discretion, result in additional or different monitoring locations, additional or different monitoring requirements, or both.

the SWDB, including, but not limited to, detailed plans and a schedule for installing and utilizing the following:

(a) Equipment to monitor and electronically record when the inlet valve to the SWDB is open; and

(b) Flow measuring and recording equipment designed to continuously, reliably, and accurately measure, within manufacturer's specifications, and record, at intervals no longer than five minutes, the time and flow rate of any water entering the SWDB through the Inlet Structure. Measured and recorded data shall be sufficient to allow calculation of the flow duration (including beginning and ending times) and total volume of the water entering the SWDB through the Inlet Structure. ExxonMobil shall also implement procedures designed to remove floating oil from the Inlet Structure prior to the SWDB.

ii. SWDB Sampling. If autosampling is the agreed upon method of sampling, the WWTP Area Wastewater Monitoring Plan shall include plans and a schedule for installing and utilizing an autosampling device designed to sample the wastewater when wastewater flow is diverted from the Inlet Structure into the SWDB. The autosampling device shall be designed to minimize headspace in each collected sample and shall be installed and used in accordance with the manufacturer's recommendations. Sampling during each diversion event shall be conducted in accordance with Attachment P-2. Manual sampling procedures shall be consistent with the sampling process set out in attachment P-2 and shall be performed in a manner to minimize headspace in each collected sample.

iii. SWDB Analysis. The SWDB samples shall be analyzed in accordance with the procedures established in Subparagraph 2.d of this Appendix.

b. EBTU Consolidated Main Influent, Stream 6.

i. Stream 6 Flow Sampling. For purposes of determining the volume of wastewater flow to the EBTU from Stream 6, equipment shall be installed that is designed to continuously, reliably and accurately measure, within manufacturer's specifications, and record at intervals no longer than fifteen minutes, the flow rate of wastewater at the location labeled as S1 in Figure P-1. The date and time of these measurements shall be electronically recorded. Plans and a schedule for installing this equipment shall be included in the WWTP Area Wastewater Monitoring Plan.

ii. Autosampler. If autosampling is the agreed upon method of sampling, ExxonMobil shall install an autosampling device that samples Stream 6 and that is designed to minimize headspace in each collected sample. The autosampler shall be installed and used in accordance with the manufacturer's recommendations. For purposes of this Consent Decree and the WWTP Area Wastewater Monitoring Plan, each individual sample collected from Stream 6 using the autosampling device shall be referred to as a "grab" sample. Manual sampling procedures shall be performed in a manner to minimize headspace in each collected sample.

iii. Stream 6 Composite Sampling. During the Monitoring Period, ExxonMobil shall collect for analysis daily composite samples from Stream 6 as follows: single grab samples shall be collected (sampling to be conducted manually or using the autosampler as described in Subparagraph 2.b.ii. above) at or near the end of the main influent pipe to the EBTU six times per calendar day, at a sampling interval of approximately four hours. For each day, the grab samples collected (typically 6) will not be analyzed individually, but will be combined to create a single daily composite sample for analysis.

iv. Stream 6 Grab Sampling. During the Monitoring Period, ExxonMobil shall collect for analysis a series of grab samples from Stream 6 as follows: once per calendar week, single grab samples shall be collected (sampling to be conducted manually or using the autosampler as described in Subparagraph 2.b.ii. above) at or near the end of the main influent pipe to the EBTU 6 times per day, at a sampling interval of approximately four hours. The grab samples collected (typically 6) will be analyzed individually. In any quarterly reports submitted pursuant to Paragraph 3, ExxonMobil may request EPA approval to reduce the frequency or eliminate grab sampling under this Paragraph.

v. Stream 6 Sample Handling. The grab samples and composite samples will be handled at all times so as to minimize headspace.

vi. Stream 6 Analysis. Stream 6 samples shall be analyzed in accordance with the procedures established in Subparagraph 2.d of this Appendix.

c. Diversion Box Flow, Streams 3 and 6.

i. Stream 3 Flow Monitoring.[10] The WWTP Area Wastewater Monitoring Plan shall include a protocol for measuring wastewater flow from the Diversion Box to Stream 3, including but not limited to, detailed plans and a schedule for installing and utilizing the following:

(a) Equipment to monitor and electronically record when water is released from the Diversion Box into the outlet identified as Stream 3 in Figure P-1; and

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[10] Based on information and belief, formed after reasonable inquiry, ExxonMobil certifies by signing this Consent Decree that all water pumped or otherwise removed from the SWDB to drain the SWDB first is sent through primary treatment (i.e., into the pre-separation flumes and through the API separator and DAF unit) before entering the EBTU. ExxonMobil shall continue that practice after the Entry Date.

(b) Flow measuring and recording equipment designed to continuously, reliably and accurately measure, within manufacturer's specifications, and record at intervals no longer than five minutes, the time and flow rate of wastewater from the Diversion Box to Stream 3. Measured and recorded data shall be sufficient to allow calculation of the flow duration (including beginning and ending times) and total volume of the water entering the Stream 3 as a result of a diversion event. Flow from the Diversion Box to Stream 3 shall be quantified prior to the mixing of Stream 3 with Stream 6.

ii. Streams 3 and 6 Diversion Event Sampling. The WWTP Area Wastewater Monitoring Plan shall include plans and a schedule for using one of the following alternative methods (Subparagraphs 2.c.ii.(a) or 2.c.ii.(b)), to be determined in ExxonMobil's sole discretion, to sample the wastewater in Streams 3 and 6 when wastewater flow is diverted from the Diversion Box to Stream 3:

(a) Manual Sampling. A level alarm shall be installed in the Diversion Box to alert the unit operator of an impending diversion to Stream 3. Upon receipt of the alarm, personnel shall be dispatched to sampling locations (one at Stream 3 and the other at Stream 6). Manual sampling of both Streams 3 and 6 shall be coordinated to start simultaneously within 15 minutes after overflow at Stream 3 begins, and shall continue in a coordinated manner. Sampling shall be done in a manner that minimizes headspace in each collected sample. No less than one sample per 15 minute interval shall be taken throughout the diversion to Stream 3 and shall continue until overflow of Stream 3 ceases. Each time any water is diverted from the Diversion Box to Stream 3, ExxonMobil shall measure the volume of water flow into Stream 3; or

(b) Autosampler. Autosampling devices shall be installed and used to sample the wastewater in Streams 3 and 6. The autosampling devices shall be designed to minimize headspace in each collected sample and shall be installed and used in accordance with the manufacturer's recommendations. Each time any water is diverted from the Diversion Box to Stream 3, ExxonMobil shall measure the volume of water flow into Stream 3, and shall use one or more autosamplers to collect samples of Stream 3 and Stream 6 at the same intervals during the diversion event. Samples at Stream 6 shall be taken simultaneously with the samples taken at Stream 3. After an initial sampling approximately 5 minutes after overflow at Stream 3 begins, no less than one sample per every 15 minute interval shall be taken throughout the diversion to Stream 3, and shall continue until overflow into Stream 3 ceases.

iii. Stream 3 and 6 Analysis. The Stream 3 and 6 samples shall be analyzed in accordance with the procedures established in Subparagraph 2.d of this Appendix. EPA and ExxonMobil agree that the samples taken at Stream 3 are primarily for informational purposes, and may be useful to identify the source of benzene that may ultimately be discharged to the EBTU.

iv. Alternative Approach to Address Stream 3. Notwithstanding the above provisions of Subparagraphs 2.c.i, ii, and iii, ExxonMobil shall have no obligations with respect to Streams 3 or 6 pursuant to Subparagraph 2.c. (including, without limitation, any requirement for monitoring, sampling, or analysis of wastewater pursuant to Subparagraphs 2.c.i, ii, or iii) if ExxonMobil submits as part of the WWTP Area Wastewater Monitoring Plan engineering information showing that it has constructed an engineering change that permanently ceases wastewater flow discharges to the EBTU from Stream 3 as depicted on Figure P-1. If this alternative approach is chosen, ExxonMobil shall attach to and submit with the WWTP Area Wastewater Monitoring Plan a certification that wastewater flow from Stream 3 to the EBTU as depicted on Figure P-1 has been permanently blocked and shall remain so unless EPA and the Applicable Co-Plaintiff are notified otherwise. Upon such notification, ExxonMobil shall be required to comply with the terms of Subparagraphs 2.c.i - 2.c.iii.

d. Analytical Requirements.

i. Analytical Method. For each wastewater sampling location (as described in Subparagraphs 2.a., 2.b., and 2.c. above), the WWTP Area Wastewater Monitoring Plan shall include a description of how each sample will be prepared in accordance with the Toxicity Characteristic Leaching Procedure (Method 1311 in EPA Publication SW-846), and a description of the method by which the benzene content of the sample will be analyzed. Methods other than Method 1311 may be approved by EPA if ExxonMobil demonstrates statistical equivalency between contemporaneous samples analyzed by Method 1311 and the proposed alternative method;

ii. Requirements Regarding Analysis of Each Sample. Each individual grab sample taken pursuant to Subparagraphs 2.a., 2.b.iv, and 2.c. shall be analyzed for benzene by the method stated in Subparagraph 2.d.i. above. Each 24-hour composite sample taken pursuant to Subparagraph 2.b.iii. shall be analyzed for benzene by the method stated in Subparagraph 2.d.i. above;

iii. Mixed Streams. The WWTP Area Wastewater Monitoring Plan shall describe the exact placement of the sampling devices and how ExxonMobil will ensure collection of a sample containing a mixture of oil and water phases proportional to the volumes of the phases in the stream. The WWTP Area Wastewater Monitoring Plan shall state: (1) that sampling streams with laminar flow is not allowed, unless the entire stream can be collected for a short time; and (2) if sampling the total flow is not practical due to high volume, then sampling at a highly turbulent mixing point will be done;

iv. QA/QC. The WWTP Area Wastewater Monitoring Plan shall include a detailed description of the Quality Assurance/Quality Control procedures that ExxonMobil will employ to ensure proper collection, handling, preparation, and analysis of samples collected.

e. Failure to Sample or Analyze Samples Pursuant to the WWTP Area Wastewater Monitoring Plan. In the event that ExxonMobil is unable, despite due diligence (e.g., inability due to power failures, equipment malfunctions, sample loss, safety issues, weather related problems), to obtain any samples (including individual grabs to be composited) or to analyze any such sample(s) as required by this Paragraph and by the WWTP Area Wastewater Monitoring Plan, then such failure(s) shall not constitute a violation of this Consent Decree if ExxonMobil: (1) notes in the operating record any sampling failures; (2) submits to EPA a written explanation of the sampling or analytical failure and all documentation related to the sampling or analytical failure within 30 business days from the failure; and (3) summarizes any sampling and analytical failures in the WWTP Area Monitoring Plan Quarterly Reports and in the WWTP Area Monitoring Plan Final Report. Any such failure(s) may, at the discretion of EPA, result in an extension of the Monitoring Period. Such an extension shall be reasonably related to the nature and extent of ExxonMobil’s sampling and/or analytical failure and other relevant considerations.

f. Precipitation Indicator. The WWTP Area Wastewater Monitoring Plan shall include plans and a schedule for installing and utilizing equipment capable of reliably and accurately measuring precipitation amounts and times at the Joliet Refinery during the Monitoring Period. The associated recording equipment shall provide electronic recording of precipitation start and stop times and precipitation amounts to allow for calculation of the duration and volume of a rainfall event. The equipment shall be configured and calibrated in accordance with the manufacturer's recommendations for proper equipment operation. The parties recognize that wet weather flow to the wastewater treatment plant may sometimes begin subsequent to commencement of actual precipitation, and that wet weather flow to the SWDB and to Stream 3 may continue after rainfall ends. The parties agree that wet weather flow also includes draining of stormwater from tank-diked areas at the facility in connection with a precipitation event.

g. Snowmelt. The WWTP Area Wastewater Monitoring Plan shall include plans and a schedule for implementing a system for use in identifying and documenting snowmelt events at the Joliet Refinery that cause wet weather flow diversion of wastewater into the SWDB during the Monitoring Period. The system shall consist of making and recording the following measurements on a daily basis when there is snow on the ground: daily snow depth (to be measured at a single location within the refinery at approximately the same time each day), the day's high temperature (which may be measured at the refinery or recorded from other reported nearby weather stations), and a description of the degree of cloudiness best describing the day (e.g. sunny, partly cloudy, cloudy, overcast, etc.). Data recorded by this system may be used as one means to support snowmelt as a cause of diversion events that may occur in the absence of precipitation when ExxonMobil believes they were caused by snowmelt. Failure by ExxonMobil to take a daily measurement shall not be a violation of this Consent Decree so long as: (1) no diversion event occurs on the day the measurement is not made, or (2) if a diversion does occur on that day, ExxonMobil is able to demonstrate through other means that the diversion was associated with a wet weather flow.

h. Nothing in this Consent Decree shall preclude ExxonMobil from availing itself of the "immediate response" provisions of RCRA, as set forth in 40 C.F.R. §§ 264.1(g)(8), 265.1(c)(11) and 270.1(c)(3) (and analogous Illinois law), for the discharge of hazardous waste (or the discharge of a material which, when discharged, becomes a hazardous waste) into a surface impoundment, provided that such discharge is directly related to an unanticipated and extraordinary event (such as a catastrophic tank rupture or activation of the HF deluge system into the facility sewer system).

3. NPDES Permit Compliance Monitoring Program.

a. ExxonMobil shall comply with all effluent limitations, permit conditions, and other requirements imposed by the NPDES Permit for the Joliet Refinery.

b. In the Quarterly Reports and Final Report required by Paragraphs 4 and 5 of this Appendix, ExxonMobil shall make supplemental reports to EPA on its NPDES permit compliance with respect to the effluent limitations and associated effluent monitoring requirements as set forth in the NPDES Permit and as documented by the Discharge Monitoring Reports ("NPDES Permit Compliance Monitoring").

4. WWTP Area Wastewater Monitoring Plan Quarterly Reports. ExxonMobil shall submit quarterly progress reports ("WWTP Area Wastewater Monitoring Plan Quarterly Reports") to EPA on a quarterly basis during collection of data pursuant to WWTP Area Wastewater Monitoring Plan. The WWTP Area Wastewater Monitoring Plan Quarterly Reports shall be due 30 days after the end of each quarterly monitoring period, or approximately 120, 210, and 300 days into the Monitoring Period. The WWTP Area Wastewater Monitoring Plan Quarterly Reports shall summarize the steps taken to implement the WWTP Area Wastewater Monitoring Plan. The data to be reported within the WWTP Area Wastewater Monitoring Plan Quarterly Report shall include:

a. For Diversion Events. For each diversion event to the SWDB and to Stream 3 that ended during the 3-month period being reported: (1) the date and time the diversion event started and ended; (2) the date and time that any wet weather or other event which caused the diversion event started and ended; (3) the total amount (in inches) of any precipitation that fell during a diversion event; (4) the total wastewater volume diverted to the SWDB and/or Stream 3; (5) the date, time, and concentration of benzene in each sample taken of Streams 4c, 3, and 6; (6) Excel spreadsheets showing all water flow measurement data points required under Subparagraphs 2.a. and 2.c.; (7) Excel spreadsheets containing all sample collection data points, including the date and time a sample was taken, and the benzene result; (8) all laboratory data related to the analysis of all SWDB and Streams 3 and 6 water samples, including but not limited to, documentation verifying that all QA/QC requirements were met; and (9) a summary of all failures to sample or analyze samples in accordance with Paragraph 2 and the WWTP Area Wastewater Monitoring Plan.

b. For Stream 6 to the EBTU Composite and Grab Samples: (1) the date and benzene concentration measured for each daily composite influent sample to the EBTU; (2) Excel spreadsheets including all water flow measurement data points required under Subparagraph 2.b.; (3) Excel spreadsheets including all sample collection data points, including the date and time a sample was taken, and the benzene results on each 24-hour composite sample that was analyzed; (4) Excel spreadsheets including all sample collection data points, including the date and time a sample was taken, and the benzene results for each individual grab sample that was individually analyzed; (5) all laboratory data related to the analysis of all Stream 6 water samples, including, but not limited to, documentation verifying that all QA/QC requirements were met; and (6) a summary of all failures to sample or analyze samples in accordance with Paragraph 2 and the WWTP Area Wastewater Monitoring Plan.

c. For NPDES Permit Requirements: (1) the first Quarterly Report shall include copies of the Joliet Refinery's Discharge Monitoring Reports for the 3-month period being reported, plus copies of Discharge Monitoring Reports for the three months preceding the start of the reporting period; (2) the subsequent Quarterly Reports shall include copies of Discharge Monitoring Reports for the 3-month period being reported; and (3) each Quarterly report shall include copies of all laboratory reports related to the attached Discharge Monitoring Reports. In each report, ExxonMobil shall identify noncompliance, if any, with the effluent limitations and associated effluent monitoring requirements in that quarter (and the preceding quarter, in the case of the first Quarterly Report), and shall identify steps that it is taking or plans to take to address such noncompliance.

5. WWTP Area Wastewater Monitoring Plan Final Report. No later than 60 days after the end of the Monitoring Period for all required monitoring activities, ExxonMobil shall submit a WWTP Area Wastewater Monitoring Plan Final Report. The WWTP Area Wastewater Monitoring Plan Final Report shall include:

a. A summary of all steps taken to implement the WWTP Area Wastewater Monitoring Plan and all data collected under the WWTP Area Wastewater Monitoring Plan, including, but not limited to, the data required to be reported under Subparagraphs 4.a and 4.b of this Appendix;

b. The data required to be reported under Subparagraph 4.a and 4.b for the final quarter of the Monitoring Period;

c. A determination whether the data collected under the WWTP Area Wastewater Monitoring Plan indicates that hazardous waste has been treated, stored, or disposed of in the SWDB and/or the EBTU, and the data relating to that determination and a detailed description of the basis for that determination;[11/]

[11/] ExxonMobil acknowledges the rulings in United States v. Mobil Oil Corporation, 1997 WL 1048911 (E.D.N.Y. Sept. 11, 1997); Texans United Education Fund v. Exxon Company USA, CV-H-96-847 (Slip Op. Mar. 2, 1998)(S.D. Tex.); and Texans United Education Fund v. Exxon Company USA, CV-H-96-847 (Slip Op. Jun. 17, 1998)(S.D. Tex.). ExxonMobil shall not contend in any administrative or judicial forum that a long-term average of discrete disposal events (or batches) of waste water is required in order to determine whether RCRA applies; provided, however that in the event that there is a change in federal RCRA law, either statutory, regulatory, or based upon EPA written guidance or federal court decisions, ExxonMobil may rely upon such change to make appropriate contentions regarding its wastes; and further provided that in the event that

(continued...)

d. A description of any noncompliance issues identified in implementing the WWTP Area Wastewater Monitoring Plan, including a description of any confirmed release of hazardous waste to the environment;

e. Attached copies of Discharge Monitoring Reports for the final quarter of the Monitoring Period, and attached copies of all laboratory reports associated with those Discharge Monitoring Reports;

f. A description of noncompliance, if any, with the effluent limitations and associated effluent monitoring requirements in the final quarter, and steps that ExxonMobil is taking or plans to take to address noncompliance identified in this Subparagraph 5.f and/or Subparagraph 4.c pursuant to the NPDES Permit Compliance Monitoring;

g. A plan and a schedule for implementing any measures necessary, if any, to bring the Joliet WWTP Area (including the SWDB and the EBTU) into full compliance with applicable legal requirements. The compliance measures shall include any reasonable physical/engineering/operational/compliance changes that are deemed necessary to comply with applicable legal requirements. The Report shall be subject to review and approval by EPA and the Applicable Co-Plaintiff. ExxonMobil shall implement all compliance measures set forth in the approved Report, in accordance with the schedule included in the WWTP Area Wastewater Monitoring Plan Final Report.

6. Sludge Characterization and Removal. Within 90 days of the Entry Date, ExxonMobil shall submit to EPA for review and approval a Sludge Characterization and Removal Plan containing a plan and a proposed schedule for the characterization and removal of sludge from the SWDB and the EBTU.

a. SWDB. The Sludge Characterization and Removal Plan shall include plans for sampling, removal, and subsequent management of sludge from the SWDB. Sludge will be removed from the SWDB when deemed operationally necessary by ExxonMobil, but no later than 24 months after entry of this Consent Decree, and will be characterized for relevant toxicity characteristics under 40 C.F.R. Part 261, Subpart C prior to removal. The SWDB sludge shall, upon removal, be managed by ExxonMobil in accordance with all applicable laws and regulations.

(...continued)
there is a changed interpretation of RCRA under the law of a State, either based upon written State agency guidance or State court decisions, ExxonMobil may rely upon such change in that State to make appropriate contentions regarding its wastes. Nothing herein shall preclude ExxonMobil from demonstrating that it has not managed RCRA-hazardous wastes, based on its design and implementation of a waste analysis plan in accordance with the principles contained in Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, EPA Publication SW-846, in the event of a continuous waste water disposal event that occurs over a period of time, and which displays chemical heterogeneity over time.

b. EBTU.

(i) Due to operational necessity prior to the Entry Date, sludges have been removed from the EBTU. The Sludge Characterization and Removal Plan shall include a certification by ExxonMobil that the sludges it removed from the EBTU were characterized and disposed of in accordance with applicable regulatory requirements.

(ii) The Sludge Characterization and Removal Plan shall include plans for additional sampling, removal, and subsequent management of sludge from the EBTU. Sludge will be removed from the EBTU when deemed operationally necessary by ExxonMobil, but no later than 24 months after the entry of this Consent Decree, and will be characterized for relevant toxicity characteristics under 40 C.F.R. Part 261, Subpart C prior to removal. The EBTU sludge shall, upon removal, be managed in accordance with all applicable laws and regulations. Notwithstanding the above, if ExxonMobil determines that it has become operationally necessary for ExxonMobil to remove or begin the removal of sludges from the EBTU prior to the Entry Date, the Parties agree that the requirements of this Paragraph shall be satisfied and no additional sampling, removal or subsequent management of sludge from the EBTU shall be required pursuant to this Consent Decree, if ExxonMobil submits to EPA in a report as set out in Paragraph 6.c, a certification that the sludges removed from the EBTU were characterized and subsequently managed in accordance with applicable regulatory requirements.

c. ExxonMobil will provide EPA with documentation of the sludge removal events set out in Subparagraphs 6.a. and 6.b. above within 60 days of the completion of the sludge removal effort. The documentation shall include any analytical data collected on the sludges and documentation showing the manner in which the sludge was removed, stored, and subsequently managed.

7. Aggressive Biological Treatment. By no later than 90 days of the Entry Date, ExxonMobil shall prepare and maintain an Aggressive Biological Treatment Plan, and shall provide EPA an informational copy of the Plan. ExxonMobil shall thereafter implement the Plan and shall take all other actions required to ensure that the EBTU is operated in compliance with the requirements applicable to aggressive biological treatment units listed hazardous waste exception under 35 Ill. Admin. Code § 721.131(b)(2)(A) and 40 C.F.R. § 261.31(b)(2). The Aggressive Biological Treatment Plan shall include:

a. High-Rate Aeration Procedure. A description of a procedure that ExxonMobil will establish and follow so that high-rate aeration in the EBTU is continuously achieved during normal operations, with the aeration system operating at minimum of 40 hp when the EBTU is full, or with the aeration system operating at a minimum of 6 hp per million gallons of treatment volume within the EBTU when the EBTU treatment volume is less than capacity. The plan shall also identify procedures for addressing any aerator outage (including but not limited to any outage due to a power failure affecting the system). ExxonMobil will monitor and record on a daily basis the number of aerators operating, total horsepower of the aerators operating, and the water volume in the EBTU.

b. Recordkeeping Procedure. A description of a procedure that ExxonMobil will establish and follow to maintain documents and data in ExxonMobil's operating or onsite records for a period of 3 years after such documents and data are created demonstrating that it meets the standard of aggressive biological treatment (including the requirements regarding horsepower and hydraulic retention time) under 35 Ill. Admin. Code § 721.131(b)(2)(A) and 40 C.F.R. § 261.31(b)(2).

8. Groundwater and Soil Characterization. Within 90 days of the Entry Date, ExxonMobil shall submit to EPA for review and approval a Groundwater and Soil Characterization Plan. The Groundwater and Soil Characterization Plan shall include plans and a schedule for quantifying the level of contamination in the groundwater and soil in the area of the SWDB and the EBTU, specifically including:

a. A summary of all relevant information concerning groundwater monitoring and soil characterization conducted over the past seven years in the SWDB and EBTU areas, including, but not limited to, information on sampling well locations, screening depths, soil sample locations, and groundwater and soil sampling results;

b. A schedule for performing and providing a hydrogeological survey in the SWDB and EBTU areas;

c. A schedule for submitting and implementing a protocol for additional groundwater monitoring and soil characterization which is capable of determining: (1) whether hazardous constituents have been released to soils or groundwater in the vicinity of the SWDB and the EBTU; (2) the rate and extent of migration of hazardous constituents; and (3) the concentrations of the hazardous constituents; and

d. A schedule for submission of the Groundwater and Soil Characterization Plan Final Report. The Groundwater and Soil Characterization Plan Final Report shall, based on the data collected pursuant to the Groundwater and Soil Characterization Plan, propose corrective actions necessary, if any, to remediate soil and groundwater of the SWDB and the EBTU areas.

9. Review and Approval of ExxonMobil Submissions Under Paragraphs 1-8 above.

a. EPA shall review all items submitted by ExxonMobil pursuant to Paragraphs 1-8 above. After review of any item submitted, EPA shall: (1) approve the item in whole or in part; (2) approve the item subject to conditions specified in the approval notice; (3) modify the item to cure the deficiencies and approve it as modified; (4) disapprove the item in whole or in part, and direct that ExxonMobil modify it; or (5) any combination of the above. EPA shall notify ExxonMobil in writing of its decision regarding each item submitted for review, and if EPA does not approve the item in whole, the notice shall specify those portions of the item that have not been approved and the reasons for not approving such item.

b. In the case of an item that has been approved in whole by EPA, ExxonMobil shall proceed to take all actions required by the item approved.

c. In the case of an item that has been approved subject to specified conditions or that has been modified and approved by EPA, ExxonMobil shall either: (1) commence implementation of the work required by the item in accordance with the approved schedule, or (2) invoke the dispute resolution procedures set forth in Section XV of the Consent Decree with respect to EPA's decision. Regardless of whether ExxonMobil invokes such dispute resolution procedures, if ExxonMobil fails to timely commence implementation of the work required by the item approved subject to specified conditions or modified and approved, ExxonMobil shall be liable for any stipulated penalties demanded under Section XI of the Consent Decree unless ExxonMobil prevails in such dispute resolution.

d. In the case of an item that has been disapproved in whole or in part by EPA, ExxonMobil shall, within 45 days of receipt of the notice of disapproval, either: (1) correct the deficiencies and resubmit the item for approval, or (2) invoke the dispute resolution procedures set forth in Section XV of the Consent Decree with respect to a notice of disapproval. Regardless of whether ExxonMobil invokes such dispute resolution procedures, if it fails to timely correct the deficiencies specified in the notice of disapproval and resubmit the item, (i) ExxonMobil shall be liable for any stipulated penalties demanded under Section XI of the Consent Decree and (ii) EPA may modify and approve the item; provided, however, that ExxonMobil shall not be liable for stipulated penalties if the stipulated penalties relate to a matter in which ExxonMobil prevails in dispute resolution. An item that is resubmitted with the same deficiencies that were identified in the notice of disapproval or with substantially similar deficiencies shall be deemed to have never been submitted for purposes of calculating stipulated penalties.

e. Notwithstanding the receipt of a notice of disapproval, ExxonMobil shall proceed, if so directed by EPA in the notice, to take any action required by any non-deficient portion of the item, unless the non-deficient portion of the item is substantially related to a disapproved item that ExxonMobil intends to dispute. However, lack of action on non-deficient portions of the submittal shall result in stipulated penalties accruing under Section XI of the Consent Decree unless ExxonMobil prevails in such dispute resolution over the substantially related disapproved item.

f. In the event that a resubmitted item, or portion thereof, is disapproved, EPA may again require ExxonMobil to correct the deficiencies, in accordance with the procedure set forth in this Paragraph. EPA may also approve the item subject to conditions specified in the approval notice or modify and approve the item as set forth in Subparagraphs 9.a and 9.c. above. In the event that EPA approves the item subject to specified conditions or modifies and approves the item, ExxonMobil shall commence implementation of the work required by the item in accordance with the schedule set forth in the item as approved, or ExxonMobil may invoke the dispute resolution procedures set forth in Section XV with respect to a decision by EPA pursuant to this Paragraph. Regardless of whether ExxonMobil invokes such dispute resolution procedures, if ExxonMobil fails to timely re-submit the item or to implement the work required by the item as approved, ExxonMobil shall be liable for any stipulated penalties demanded under Section XI unless ExxonMobil prevails in such dispute resolution.

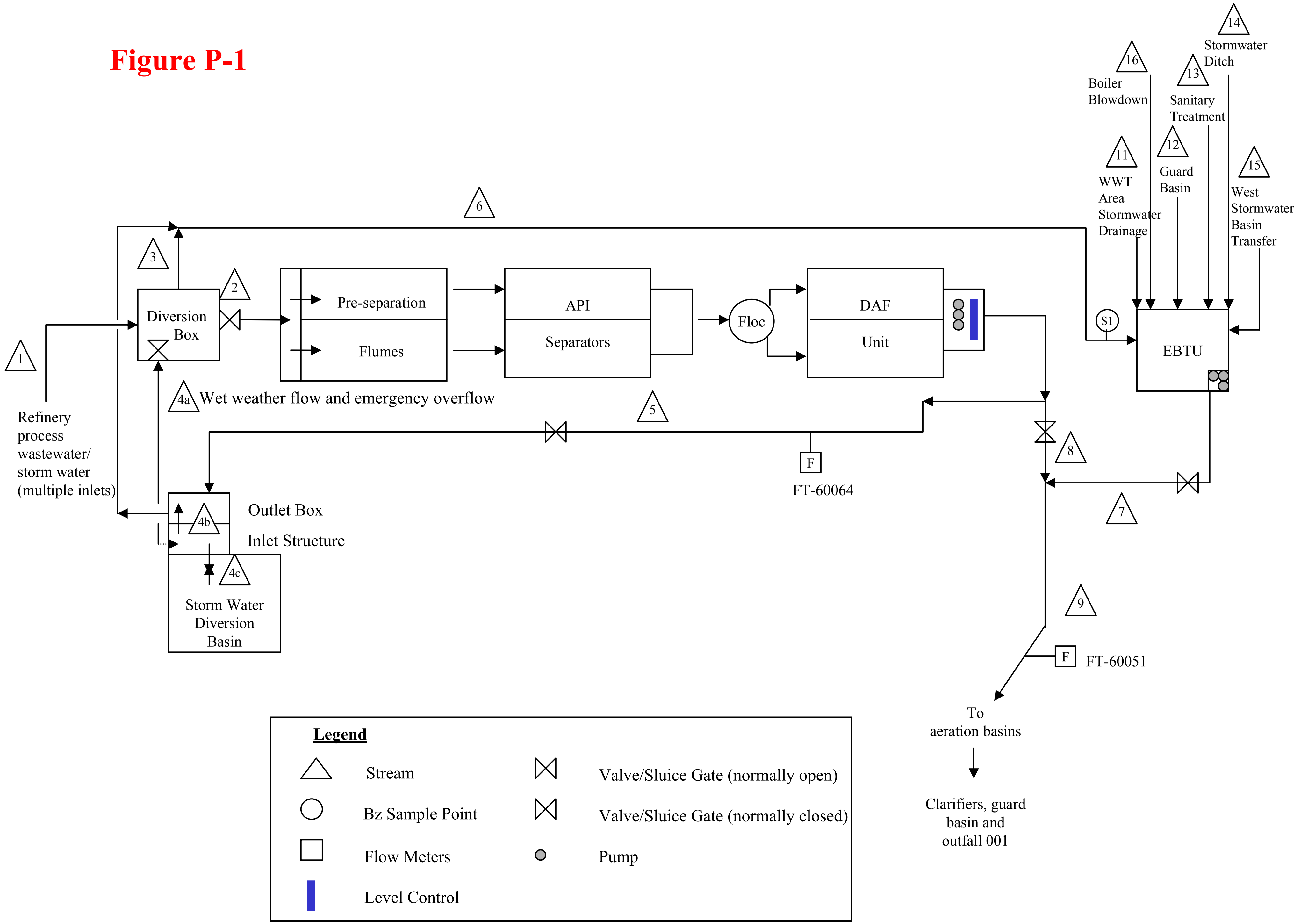
g. All items required to be submitted to EPA under Paragraphs 1-8 above shall, upon approval, be enforceable under this Consent Decree. In the event EPA approves a portion of an item required to be submitted to EPA under this Consent Decree, the approved portion shall be enforceable under this Consent Decree. ExxonMobil retains the right to invoke dispute resolution regarding all items it is required to submit for review and approval under this Consent Decree.

h. Paragraph 229 in the Section of the Consent Decree governing dispute resolution provides that the Parties shall expeditiously schedule a meeting to discuss a dispute informally not later than fourteen (14) days after receipt of a written notice of dispute. If ExxonMobil disputes EPA's approval with conditions, modification, or disapproval of an item submitted pursuant to Paragraphs 1-8 in this Appendix P, then stipulated penalties under Consent Decree Subparagraphs 201.a -201.k shall not begin to accrue any earlier than twenty-one (21) days after a notice of dispute.

Appendix P: **Figure P-1**

[Figure P-1 is on the following page]

Figure P-1


1
Refinery process wastewater/ storm water (multiple inlets)
Diversion Box
2
3
4a
Wet weather flow and emergency overflow
Pre-separation
Flumes
API
Separators
Floc
DAF
Unit
5
6
F
FT-60064
Outlet Box
Inlet Structure
4b
4c
Storm Water Diversion Basin
EBTU
S1
7
8
9
F
FT-60051
To aeration basins
Clarifiers, guard basin and outfall 001
16
Boiler Blowdown
14
Stormwater Ditch
13
Sanitary Treatment
11
WWT Area Stormwater Drainage
12
Guard Basin
15
West Stormwater Basin Transfer
Legend
Stream
Bz Sample Point
Flow Meters
Level Control
Valve/Sluice Gate (normally open)
Valve/Sluice Gate (normally closed)
Pump

Appendix P: Attachment P-2

<u>Sampling, Analysis and Evaluation of SWDB Stream</u>

A. Overview

Each time any water is diverted into the SWDB, ExxonMobil will use a flow meter to measure the rate of water flow into the SWDB, and one or more autosamplers to collect samples at intervals during the diversion event. The individual grab samples collected by the autosampler(s) will be analyzed pursuant to Subparagraph 2.d.i of Appendix P.

B. Sample Collection Interval

ExxonMobil shall collect the first sample(s) within 15 minutes of the beginning of a discharge. Thereafter, if an autosampler is used, the interval between samples will be based on pre-defined volumes of water that have flowed into the SWDB. If manual sampling is used, the interval between the samples will be based on pre-defined volumes of water that have flowed into the SWDB to the extent practicable. These interval volumes may be adjusted by ExxonMobil either before a diversion event (for example, to accommodate anticipated size of the storm) or during a diversion event (for example, to accommodate the conditions encountered during a diversion event). Changes to the sample collection interval will be made while keeping in mind the need to collect enough samples to adequately characterize changes in benzene concentration during the diversion event. Regardless of the above, however, ExxonMobil shall take at least 1 sample every 90 minutes during any release event.

The following is an example of possible intervals for sample collection, illustrating the concept of variable sample collection intervals. The flow rate of water entering the SWDB will be monitored and recorded at intervals no larger than five minutes. Samples after the first will be taken at intervals determined by the volume of water that has entered the SWDB since the previous sample. For example, the next three samples might be taken at 25,000 gallon intervals, the following three at 50,000 gallon intervals, the next eleven at 100,000 gallon intervals, and subsequent samples scheduled at increased gallon intervals as shown below.

Sample Number	Sampling Time (min)	Volume (gal) Increment	Total
1	5.0		30,000
		25,000	
2	27.5		55,000
		25,000	
3	40.0		80,000
		25,000	
4	52.5		105,000
		50,000	
5	77.5		155,000
		50,000	
6	102.5		205,000
		50,000	
7	127.5		255,000
		100,000	
8	177.5		355,000
		100,000	
with samples continuing at increased increments			
19	827.5	150,000	1,655,000
20	902.5	150,000	1,805,000
21	1002.5	200,000	2,005,000
22	1102.5	200,000	2,205,000
no sample	1125.0	45,000	2,250,000
. . . until event ceases			

Hypothetical diversion event ended 1125 minutes after beginning.

For simplicity, in this hypothetical example the flow into the SWDB is assumed to be constant at 2,000 gpm (except for the first 5 minute interval). In a real diversion event the flow will be calculated based on the measured values at intervals no larger than 5 minutes. Also, in this hypothetical example, flow into the SWDB is shown to occur in a single uninterrupted event. In a real diversion event, the inlet valve may be opened and later closed, and then have to be reopened to allow additional flow, for example if a storm's intensity lessens for a while and then increases again. In such an event, as long as the individual openings of the inlet valve all capture the wet weather flow from the same rainfall, the total flow into the SWDB arising from the same rainfall event, whether diverted by one or more than one set of inlet valve open/close operations, will be evaluated as a single event, arising from a single storm.

Appendix Q: Diesel Emissions Reduction SEPs

ExxonMobil shall develop and satisfactorily complete implementation of diesel emissions reduction SEPs in accordance with the following:

A. Allocation: The $1,300,000 to be expended on diesel emissions reduction SEPs shall be allocated as follows:

1. ExxonMobil shall spend no less than $250,000 to implement diesel emissions reduction SEPs in the general area where ExxonMobil's Torrance Refinery is located.

2. ExxonMobil shall spend no less than $300,000 to implement diesel emissions reduction SEPs in the general area where ExxonMobil's Billings Refinery is located.

3. ExxonMobil shall spend no less than $250,000 to implement diesel emissions reduction SEPs in the general area where ExxonMobil's Joliet Refinery is located.

4. ExxonMobil shall spend no less than $250,000 to implement diesel emissions reduction SEPs in the general area where ExxonMobil's Baytown Refinery is located.

5. ExxonMobil shall spend no less than $250,000 to implement diesel emissions reduction SEPs in the general area where ExxonMobil's Beaumont Refinery is located.

B. Schedule: By no later than one year after the Consent Decree Entry Date, ExxonMobil shall submit a Statement of Work ("SOW") for each diesel emissions reduction SEP that it proposes to perform, which shall include a description of how the SEP meets the criteria in this Appendix, a schedule for development and implementation, and an estimated cost. Each SOW shall be subject to approval by EPA, after consultation with the appropriate state and local authorities. ExxonMobil shall complete implementation of the approved SOWs by no later than December 31, 2009.

C. Project Criteria: ExxonMobil's agreement with a third-party implementing a diesel emissions reduction SEP shall specify that the SEP shall satisfy each of the following criteria and shall require the third-party to certify in writing to ExxonMobil and EPA that the following criteria have been met:

1. It shall involve the retrofit of high-emitting, in-service heavy duty diesel vehicles with emissions control equipment or the replacement of vehicles or engines in order to reduce emissions of particulates and/or ozone precursors.

2. It shall include as a goal the creation of benefits to sensitive populations that are otherwise exposed to particulate emissions and ozone precursors from such vehicles.

3. It shall cover the hardware and installation costs, and may provide also for incremental maintenance costs and/or costs of repairs on such hardware for a period of up to four years after installation.

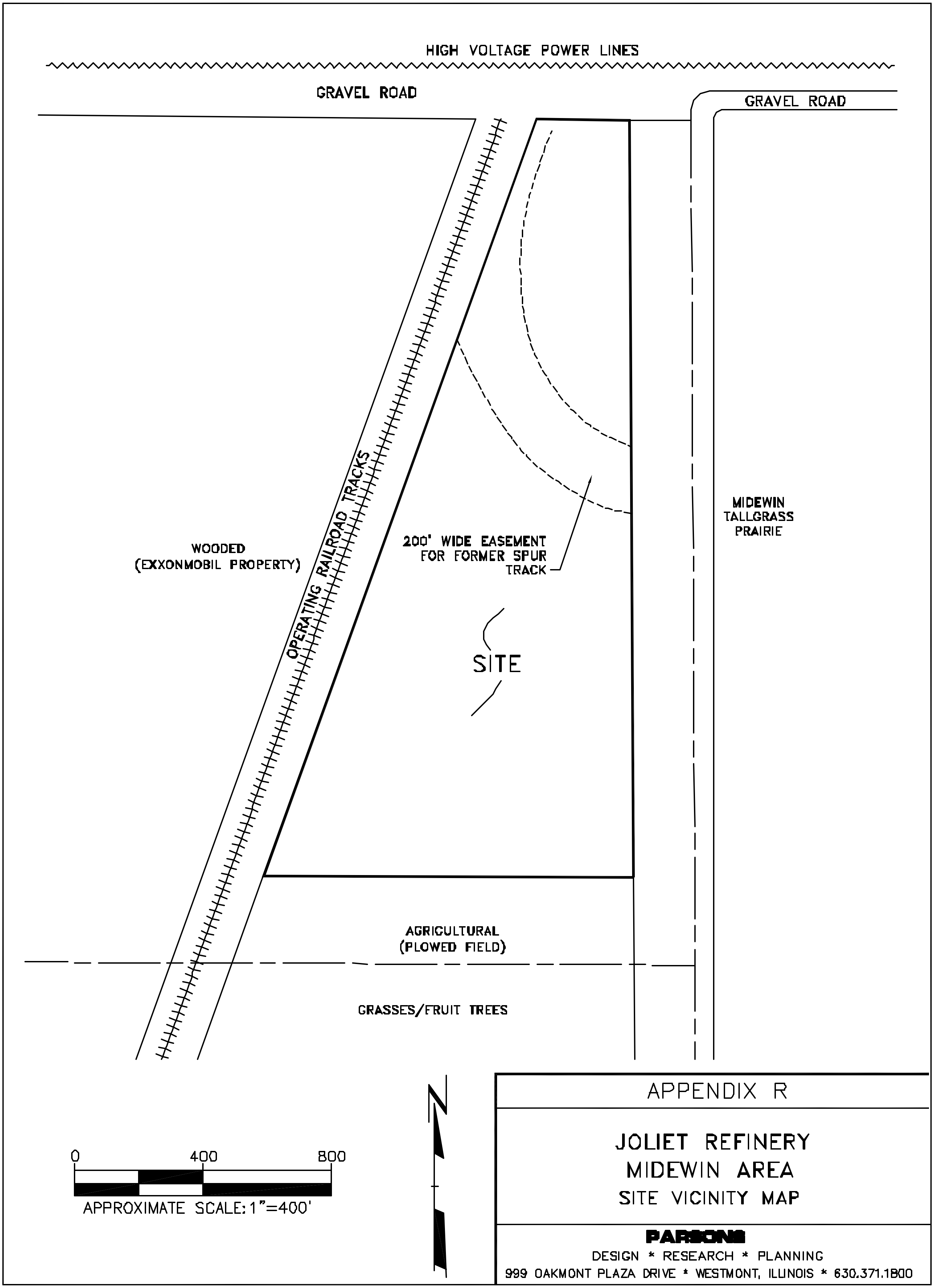
4. It shall cover fleets for which the affected municipality, local governmental entity, or other owner/operator has committed: (i) to maintain any equipment installed in connection with the SEP during and after completion of the SEP; (ii) to use ultra low-sulfur diesel fuel with the affected vehicles during and after completion of the SEP; and (iii) to the extent feasible, to take steps to achieve additional emissions reduction benefits in connection with the project, such as by implementing an idle control program.

5. It shall involve vehicles that are operated an average of at least four days per week. For vehicles operated on a seasonal basis, the four-day-per-week minimum threshold under the previous sentence shall apply during the season(s) in which the vehicles are operated.

D. Reservation: EPA reserves the right to reject all or part of a project plan that could be funded by EPA under Section 103 of the Clean Air Act, or that is otherwise inconsistent with EPA SEP Policy, applicable EPA guidance, or any other provision of law.

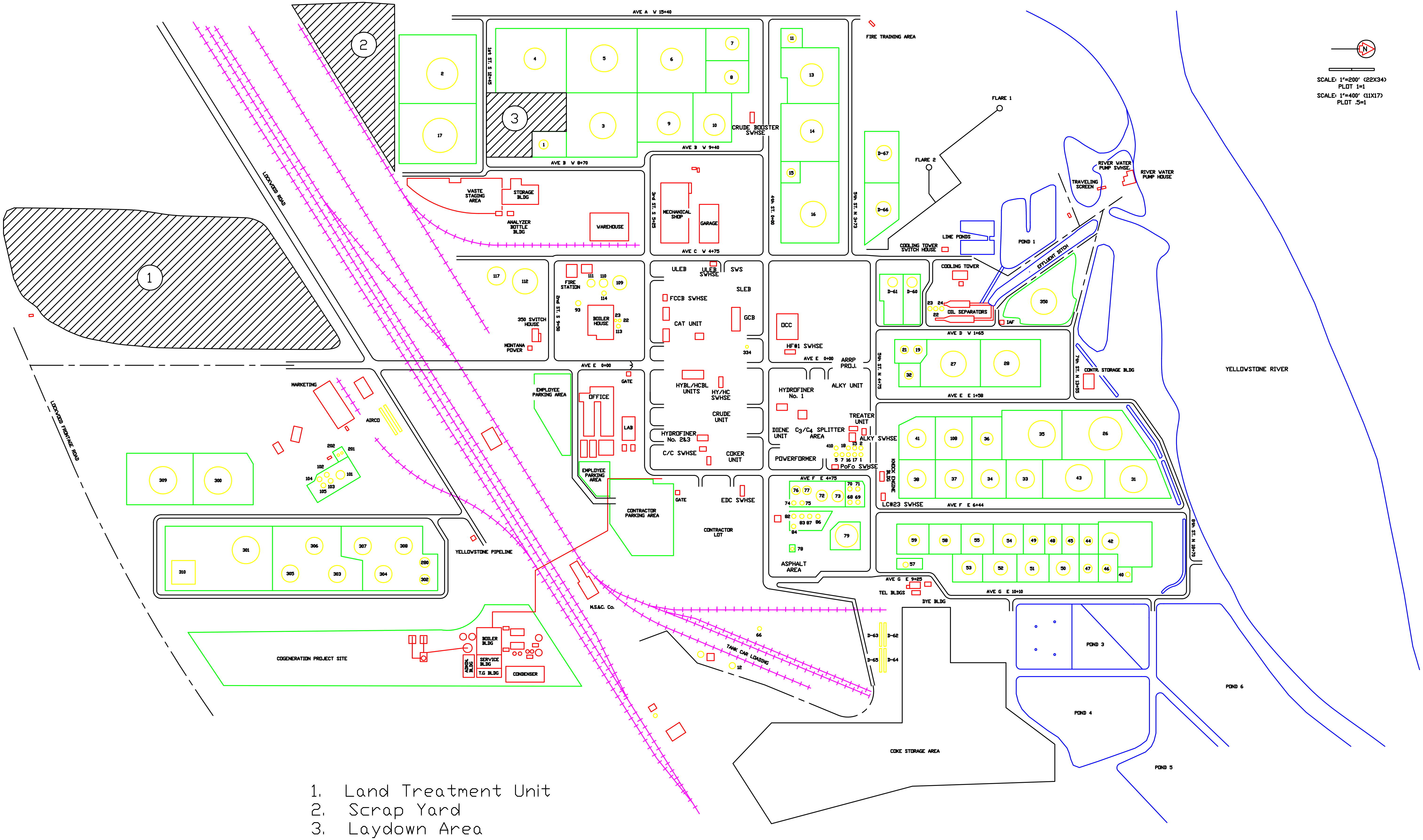
Appendix R: **Drawing of Real Estate Referenced in Consent Decree Subparagraph 156.d.(1)**

[Appendix R is on the following page]


HIGH VOLTAGE POWER LINES
GRAVEL ROAD
GRAVEL ROAD
OPERATING RAILROAD TRACKS
WOODED
(EXXONMOBIL PROPERTY)
200' WIDE EASEMENT
FOR FORMER SPUR
TRACK
SITE
MIDEWIN
TALLGRASS
PRAIRIE
AGRICULTURAL
(PLOWED FIELD)
GRASSES/FRUIT TREES
0
400
800
APPROXIMATE SCALE: 1"=400'
N
APPENDIX R
JOLIET REFINERY
MIDEWIN AREA
SITE VICINITY MAP
PARSONS
DESIGN * RESEARCH * PLANNING
999 OAKMONT PLAZA DRIVE * WESTMONT, ILLINOIS * 630.371.1800

Appendix S: **Drawing of Billings Refinery Scrap Yard and Laydown Areas and Land Treatment Unit as Referenced in Consent Decree Paragraphs 137 and 138**

[Appendix S is on the following page]

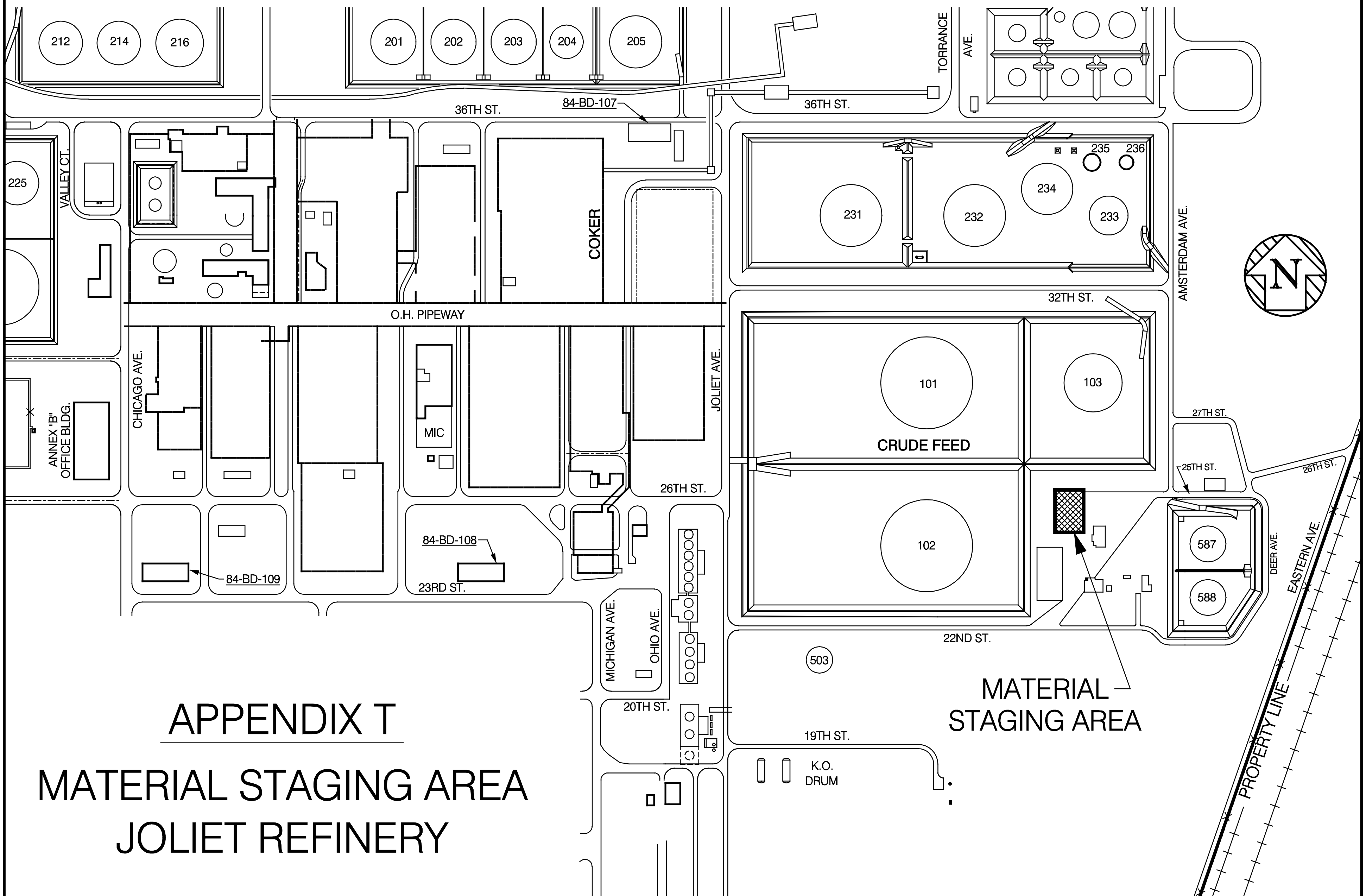


1. Land Treatment Unit
2. Scrap Yard
3. Laydown Area

Appendix S:
Billings Refinery Scrap Yard,
Laydown Area and Land Treatment Unit

Appendix T: **Drawing of Joliet Material Staging Area Referenced in Consent Decree Subparagraph 135.a**

[Appendix T is on the following page]



APPENDIX T

MATERIAL STAGING AREA
JOLIET REFINERY