IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS

UNITED STATES OF AMERICA, STATE OF GEORGIA, STATE OF ILLINOIS, STATE OF LOUISIANA, and STATE OF NEW JERSEY Plaintiffs, v. CITGO PETROLEUM CORPORATION, CITGO REFINING AND CHEMICALS COMPANY, L.P., PDV MIDWEST REFINING, L.L.C., and CITGO ASPHALT REFINING COMPANY, Defendants.	)	H-04-3883 No.

CONSENT DECREE

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Koch Guidance

CONSENT DECREE

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 defendants CITGO Petroleum Corporation, CITGO Refining and Chemicals Company, L.P., PDV Midwest Refining, L.L.C., and CITGO Asphalt Refining Company (collectively "CITGO") have violated and/or continue to violate the requirements of the Clean Air Act, and the regulations and permits promulgated thereunder at CITGO's petroleum refineries in Lemont, Illinois, Lake Charles, Louisiana, and Corpus Christi, Texas, and at CITGO's asphalt refineries in Savannah, Georgia and Paulsboro, New Jersey (collectively "Covered Refineries");

WHEREAS, the United States specifically alleges that CITGO 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) and at Title 40, Part 51, Appendix S, and at 40 C.F.R. § 52.24 ("PSD/NSR Regulations"), for fuel gas combustion devices, fluid catalytic cracking unit catalyst regenerators for NOx, SO_2, CO and PM and for sulfuric acid plants;

2) New Source Performance Standards ("NSPS") found at 40 C.F.R. Part 60, Subparts A and J ("Refinery NSPS Regulations") and Subpart H, 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 and for sulfuric acid plants;

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 Subparts VV and 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 specifically alleges with respect to the Covered Refineries that, upon information and belief, CITGO has been and/or continues to be in violation of the state implementation plans ("SIPs") and other state rules adopted by the states in which the Covered Refineries are located to the extent that such plans or rules implement, adopt or incorporate the above-described Federal requirements;

WHEREAS, the State of Georgia ("Georgia"), the State of Illinois ("Illinois"), the State of Louisiana ("Louisiana"), and the State of New Jersey ("New Jersey") (collectively "Co-Plaintiffs") have alleged 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 Section V.J. ("Control of Acid Gas Flaring Incidents 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 Paragraph 10 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, CITGO 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, CITGO 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, CITGO and the Co-Plaintiffs under the Clean Air Act and the corollary state statutes, and 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, by entering into this Consent Decree CITGO is committed to reducing air pollutant emissions from its operations;

WHEREAS, the United States, Georgia, Illinois, Louisiana, New Jersey, and CITGO agree that the affirmative relief and environmental projects identified in Sections V and VIII of this Consent Decree will reduce annual emissions from the Covered Refineries by the following amounts: 1) nitrogen oxide by approximately 7,162 tons; 2) sulfur dioxide by approximately 23,250 tons; and 3) particulate matter ("PM") by approximately 915 tons;

WHEREAS, EPA recently issued PSD Rules and PSD/NSR Regulations, see 67 Fed. Reg. 80186-80289 (2002), that identify and address "Pollution Control Projects" and "Clean Units" and the applicability of PSD/NSR permitting requirements to such Projects or Units;

WHEREAS, EPA previously issued guidance ("Pollution Control Projects and New Source Review (NSR) Applicability", July 1, 1994) identifying and addressing "Pollution Control Projects" and the applicability of PSD/NSR permitting requirements to such Projects;

WHEREAS, EPA agrees that under the recently issued PSD Rules and PSD/NSR Regulations that identify and address "Clean Units", see 67 Fed. Reg. 80186 et seq., units that accept the following emission limits under this Consent Decree may be considered "Clean Units" with respect to the identified pollutants:

For FCCUs:

– 20 ppmvd NOx at 0% O2 on a 365-day rolling average basis

– 25 ppmvd SO2 at 0% O2 on a 365-day rolling average basis

– 100 ppmvd CO at 0% O2 on a 365-day rolling average basis

– 0.5 pounds of PM per 1,000 pounds of coke burned on a 3-hour average basis

For Heaters and Boilers:

– 0.020 lbs/mmBTU NOx

Units with higher limits may be considered "Clean Units" under applicable rules at the discretion of the permitting agency.

WHEREAS, EPA agrees that under recently issued PSD Rules and PSD/NSR Regulations that identify and address "Pollution Control Projects", see 67 Fed. Reg. 80186 et seq., and under prior EPA guidance ("Pollution Control Projects and New Source Review (NSR) Applicability," July 1, 1994), activities under taken by CITGO to comply with Section V and Section VIII of this Consent Decree may be considered "Pollution Control Projects" under such rules, regulations, and guidance, provided that CITGO complies with the requirements for "Pollution Control Projects" under applicable federal, state, and local regulations and policies.

WHEREAS, projects undertaken pursuant to this Consent Decree are for the purposes of abating or controlling atmospheric pollution or contamination by removing, reducing or preventing the emission of pollutants and, as such, may be considered for certification as Pollution Control Facilities by federal, state or local authorities.

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

WHEREAS, the Parties agree that: (a) settlement of the matters set forth in the Complaint (filed herewith), and those orders and notices identified in Appendix A, is in the best interests of the Parties, and the public; and (b) 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 those orders and notices identified in Appendix A, and in Section XVI of the Consent Decree ("Effect of Settlement"), and before the taking of any testimony, without adjudication of any issue of fact or law, and upon the consent and agreement of the Parties to the Consent Decree, it is hereby ORDERED, ADJUDGED and DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action and over the Parties pursuant to 28 U.S.C. §§ 1331, 1345 and 1355. In addition, this Court has jurisdiction over the subject matter of this action pursuant to Sections 113(b) and 167 of the CAA, 42 U.S.C. § 7413(b) and 7477. The Complaint states a claim upon which relief may be granted for injunctive relief and civil penalties against CITGO under the Clean Air Act. Authority to bring this suit is vested in the United States Department of Justice by 28 U.S.C. §§ 516 and 519, Section 305 of the CAA, 42 U.S.C. § 7605.

2. Venue is proper in the Southern District of Texas pursuant to Section 113(b) of the CAA, 42 U.S.C. § 7413(b), and 28 U.S.C. §§ 1391(b) and (c), and 1395(a). CITGO 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 States of Georgia, Illinois, Louisiana, and New Jersey as parties or intervenors in this action.

3. Notice of the commencement of this action has been given to the States of Georgia, Illinois, Louisiana, New Jersey and Texas 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 CAA, 42 U.S.C. § 7413(b).

II. APPLICABILITY AND BINDING EFFECT

4. The provisions of the Consent Decree shall apply to the Savannah Refinery, the Lemont Refinery, the Lake Charles Refinery, the Paulsboro Refinery, the Corpus Christi East Refinery and the Corpus Christi West Refinery ("Covered Refineries"). The provisions of the Consent Decree shall be binding upon the United States, the Co-Plaintiffs, and CITGO, its successors and assigns.

5. CITGO, 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. CITGO 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 and shall provide a copy of the Consent Decree to any successor in interest. CITGO shall notify the United States, and the appropriate Co-Plaintiff, in accordance with the notice provisions set forth in Paragraph 270 (Notice), of any successor in interest at least thirty (30) days prior to any such transfer.

7. CITGO 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 such Covered Refinery or portion of a Covered Refinery applicable to the transferee. In the event of such transfer, CITGO shall notify the United States and the applicable Co-Plaintiff, but if such transfer occurs before CITGO achieves all of the NOx reductions required by Paragraph 54, CITGO shall then submit an allocation to EPA for that Covered Refinery's share of NOx reduction requirements of Paragraph 54 that will apply individually to the transferred Covered Refinery after such transfer (such allocation may be zero). By no earlier than thirty (30) days after such notice, CITGO may file a motion to modify the Consent Decree to make the terms and conditions of the Consent Decree applicable to the transferee. CITGO 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 and XIV, below, CITGO 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. CITGO shall provide a copy of this Consent Decree (or an extract of relevant, applicable provisions of this Consent Decree) to each consulting or contracting firm that is retained to perform work required under this Consent Decree upon execution of any contract relating to such work. No later than thirty (30) days after the Date of Lodging of the Consent Decree, CITGO also shall provide a copy of this Consent Decree (or an extract of relevant, applicable provisions of this Consent Decree) to each consulting or contracting firm that CITGO already has retained to perform the work required under this Consent Decree. Copies of the Consent Decree (or an extract of relevant, 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 of 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 Georgia Air Quality Act, OCGA 12-9-1; the Illinois Environmental Protection Act, 415 ILCS 5/8: Title II Air Pollution; Louisiana Air Control Law, LSA - R.S. 30:2051-2065; the New Jersey Air Pollution Act, 26:2C-1 to 25.2; and the Texas Air Act, Acts 1989, 71st Leg., ch. 382.

IV. <u>DEFINITIONS</u>

10. Unless otherwise defined herein, terms used in the Consent Decree shall have the meaning given to those terms in the Clean Air Act, and the implementing regulations promulgated thereunder. The following terms used in this Consent Decree shall be defined, 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 a 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 listed in Appendix B-2 that are used by 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 in Appendix B-2 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 Federal and State Agencies" shall mean, with respect to the Savannah Refinery, EPA's Office of Regulatory Enforcement, EPA's Region 4, and the Georgia Department of Natural Resources; with respect to the Lemont Refinery, EPA's Office of Regulatory Enforcement, EPA's Region 5, and the Illinois Environmental Protection Agency; with respect to the Lake Charles Refinery, EPA's Office of Regulatory Enforcement, EPA's Region 6 and the Louisiana Department of Environmental Quality; with respect to the Paulsboro Refinery, EPA's Office of Regulatory Enforcement, EPA's Region 2, and the New Jersey Department of Environmental Protection; and with respect to the Corpus Christi East and Corpus Christi West Refineries, EPA's Office of Regulatory Enforcement, and EPA's Region 6.

F. "Applicable State Agency" shall mean, with respect to the Savannah Refinery, the Georgia Department of Natural Resources; with respect to the Lemont Refinery, the Illinois Environmental Protection Agency; with respect to the Paulsboro Refinery, the New Jersey

Department of Environmental Protection; and with respect to the Corpus Christi East and Corpus Christi West Refineries, as used in Paragraphs 131, 132 and 134 of this Consent Decree only, the Texas Commission on Environmental Quality. As used in Paragraphs 131, 132 and 134 of this Consent Decree only, "Applicable State Agency" shall also include any regional or local air quality board that issues permits referred to in those Paragraphs.

G. "Calendar quarter" shall mean the three month period ending on March 31st, June 30th, September 30th, and December 31st.

H. "CEMS" shall mean continuous emissions monitoring system.

I. "CITGO" shall mean CITGO Petroleum Corporation, CITGO Refining and Chemicals Company, L.P., PDV Midwest Refining, L.L.C., and CITGO Asphalt Refining Company, their successors and assigns.

J. "Consent Decree" or "Decree" shall mean this Consent Decree, including any and all appendices attached to the Consent Decree.

K. "Corpus Christi East Refinery" shall mean the refinery owned and operated by CITGO and located at 1801 Nueces Bay Boulevard, Corpus Christi, Texas.

L. "Corpus Christi West Refinery" shall mean the refinery owned and operated by CITGO and located at 7350 Interstate Hwy. 37, Corpus Christi, Texas.

M. "Covered FCCUs" shall mean the following six FCCUs that CITGO owns and operates:

- Corpus Christi FCCU # 1 at the Corpus Christi East Refinery
- Corpus Christi FCCU # 2 at the Corpus Christi East Refinery
- Lake Charles FCCUs # A, B, and C at the Lake Charles Refinery

• Lemont FCCU at the Lemont Refinery

N. "Covered Refineries" shall mean the following refineries that are subject to the requirements of this Consent Decree: the Corpus Christi East and Corpus Christi West Refinery, the Lake Charles Refinery, the Lemont Refinery, the Paulsboro Refinery, and the Savannah Refinery.

O. "CO" shall mean carbon monoxide.

P. "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.

Q. "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 Southern District of Texas.

R. "Date of Entry" or "Date of Entry of the Consent Decree" shall mean the date the Consent Decree is entered by the United States District Court for the Southern District of Texas.

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

T. "FCCU" shall mean a fluidized catalytic cracking unit, its regenerator and associated CO boiler(s) where present.

U. "Flaring Device" shall mean an AG and/or an HC Flaring Device.

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

W. "Full Burn Operation" shall mean when essentially all of the CO produced in the FCCU regenerator is converted to CO_2 inside the regenerator and there is excess O_2 present in the regenerator flue gas. Specifically, for the Lemont FCCU, Full Burn Operation shall occur when less than 500 ppm CO and greater than 0.2% O_2 by volume is present in the regenerator flue gas, and for Corpus Christi FCCU #1, Full Burn Operation shall occur when greater than 0.2% O_2 by volume is present in the regenerator flue gas.

X. "GDNR" shall mean the Georgia Department of Natural Resources and any successor departments or agencies of the State of Georgia.

Y. "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.

Z. "Hydrocarbon Flaring Device" or "HC Flaring Device" shall mean the devices listed in Appendix B 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 B 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.

AA. "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, at 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.

BB. "Hydrotreater Outage" shall mean the period of time during which the FCCU operation is affected as a result of catalyst change-out operations, shutdowns required by ASME pressure vessel requirements or state boiler codes, or as a result of Malfunction, that prevents the hydrotreater from effectively producing the quantity and quality of feed necessary to achieve established FCCU emission performance.

CC. "IEPA" shall mean the Illinois Environmental Protection Agency and any successor departments or agencies of the State of Illinois.

DD. "Incremental NOx Reduction Factor" and "Incremental SO_2 Pick-up Factor" shall mean:

$$\frac{PR_i - PR_{i-1}}{CAR_i - CAR_{i-1}}$$

where:

PR_i
=Pollutant (NOx or SO_2) reduction rate at increment i in pounds per day from the baseline

PR_{i-1}
=Pollutant (NOx or SO_2) reduction rate at the increment prior to increment i in pounds per day from the baseline

CAR_i
=Pollutant (NOx or SO_2) Reducing Catalyst Additive Rate at increment i in pounds per day from the baseline

CAR_{i-1}
=Pollutant (NOx or SO_2) Reducing Catalyst Additive Rate at the increment prior to increment i in pounds per day from the baseline

EE. "Lake Charles Refinery" shall mean the refinery owned and operated by CITGO and located in Lake Charles, Louisiana;

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

GG. "Lemont Refinery" shall mean the refinery owned and operated by CITGO and located in Lemont, Illinois;

HH. "Low NOx Combustion Promoter" shall mean a catalyst that contains no platinum that is added to an FCCU, consistent with Appendix D, or such other technology as may be approved by EPA, that minimizes NOx formation while maintaining its effectiveness as a combustion promoter.

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

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

KK. "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.

LL. "NJDEP" shall mean the New Jersey Department of Environmental Protection and any successor departments or agencies of the State of New Jersey.

MM. "NOx" shall mean nitrogen oxides.

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

OO. "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.

PP. "NSPS Hydrocarbon Flaring Device" or "NSPS HC Flaring Device" shall mean the Hydrocarbon Flaring Devices listed in Appendix B-1 which are, or will be, regulated as fuel gas combustion devices under NSPS Subparts A and J.

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

RR. "PM" shall mean particulate matter.

SS. "Parties" shall mean the United States, the Co-Plaintiffs, and CITGO.

TT. "Paulsboro Refinery" shall mean the asphalt refinery owned and operated by CITGO and located in Paulsboro, New Jersey.

UU. "Co-Plaintiffs" shall mean the States of Georgia, Illinois, Louisiana, and New Jersey.

VV. "Pollutant Reducing Catalyst Additive" shall mean either a NOx Reducing Catalyst Additive or a SO_2 Reducing Catalyst Additive.

WW. "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.

XX. "Savannah Refinery" shall mean the asphalt refinery owned and operated by CITGO and located in Savannah, Georgia.

YY. "Scheduled Maintenance" shall mean any shutdown of any emission unit or control equipment that CITGO schedules at least fourteen (14) days in advance of the shutdown for the purpose of undertaking maintenance of such unit or control equipment.

ZZ. "Shutdown" shall mean the cessation of operation of an affected facility for any purpose.

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

BBB. "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.

CCC. "Startup", as specified in 40 C.F.R. Section 60.2, shall mean the setting in operation of an affected facility for any purpose.

DDD. "SO_2" shall mean sulfur dioxide.

EEE. "SRP" or "Claus Sulfur Recovery Plant" shall mean a process unit that recovers sulfur from hydrogen sulfide by a vapor phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

FFF. "Tail Gas" or "TG" shall mean exhaust gas from the Claus trains and/or the tail gas unit ("TGU") section of the SRP.

GGG. "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.

HHH. "Tail Gas Incident" shall mean combustion of Tail Gas that either is:

i. combusted in a flare and results in 500 pounds or more of SO_2 emissions in any 24 hour period ; or

ii. 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.

CITGO 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.

III. "Total Catalyst" shall mean all forms of catalyst added to the FCCU, including but not limited to base catalyst and equilibrium catalyst, but excluding Pollutant Reducing Catalyst Additive.

JJJ. "Upstream Process Units" shall mean all amine contactors, amine scrubbers, and sour water strippers at the Covered Refineries, 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.

KKK. "Weight % Pollutant Reducing Catalyst Additive Rate" shall mean:

$$\frac{\text{Amount of Pollutant Reducing Catalyst Additive (lb/day)}}{\text{Amount of Total Catalyst added (lb/day)}} \times 100\%$$

V. AFFIRMATIVE RELIEF / ENVIRONMENTAL PROJECTS

A. NOx EMISSIONS REDUCTIONS FROM FCCUs.

11. **General.** CITGO shall implement a program to reduce NOx emissions from the Covered FCCUs. Pursuant to Section V.N of this Consent Decree, CITGO shall apply for permits containing NO_x emission limits established under this Consent Decree. CITGO will monitor compliance with the emission limits through the use of CEMS.

12. **Continuous Emissions Monitoring Systems ("CEMS").** Beginning no later than the dates listed below, CITGO shall, commence operation of, calibrate and certify CEMS for NOx,O_2, SO_2, CO and Opacity at the following FCCUs:

	O_2	SO_2	NOx	CO	Opacity
Corpus Christi East #1	Date of Entry	April 1, 2007	Date of Entry	April 1, 2007	Date of Entry
Corpus Christi East #2	Date of Entry	Date of Entry	Date of Entry	Date of Entry	Date of Entry
Lake Charles Unit A	October 1, 2005	October 1, 2005	October 1, 2005	October 1, 2005	October 1, 2005
Lake Charles Unit B	October 1, 2005	October 1, 2005	October 1, 2005	October 1, 2005	October 1, 2005
Lake Charles Unit C	October 1, 2005	October 1, 2005	October 1, 2005	October 1, 2005	October 1, 2005
Lemont	Date of Entry	Date of Entry	Date of Entry	Date of Entry	Date of Entry

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. However, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3, and 5.1.4, CITGO 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 will need to be re-calibrated and re-certified. If use of a continuous opacity monitor ("COMS") is not feasible on an FCCU with a Wet Gas Scrubber, CITGO shall submit to EPA an alternative monitoring plan no later than six (6) months prior to the date CITGO intends to commence operation of each Wet Gas Scrubber ("WGS").

13. **NOx Emission Limit at Corpus Christi FCCU 2**. Beginning no later than June 1, 2005, CITGO shall comply with an interim NO_x emission limit of 23 ppmvd at 0% O_2 on a 365-day rolling average basis and 60 ppmvd at 0% O_2 on a 24-hour rolling average basis from FCCU 2 at the Corpus Christi East Refinery ("Corpus Christi FCCU 2").

14. [Intentionally left blank]

15. [Intentionally left blank]

16. **NOx Minimization Study at Corpus Christi FCCU 2.** By no later than June 1, 2005, CITGO shall begin a 2-month study of the Corpus Christi FCCU 2 regenerator in an effort to minimize NOx emissions by minimizing regenerator oxygen and usage of platinum combustion promoter to the extent practicable without creating a safety problem, interfering with conversion or processing rates, yield selectivity or otherwise exceeding previously established

and complied with operating limits, provided such cannot be reasonably compensated for by adjustment(s) to other operating parameters. ("NOx Minimization Study"). By no later than August 31, 2005, CITGO shall submit the results of such NOx Minimization Study to EPA. As part of the NOx Minimization Study, CITGO shall provide all of the parameters listed in Paragraph 19 on a daily average basis during the NOx Minimization Study. Upon request by EPA, CITGO shall submit any additional, readily available data that EPA determines it needs to evaluate the NOx Minimization Study.

17. **NOx Minimization Protocol for Corpus Christi FCCU 2.** By no later than August 31, 2005, CITGO shall propose for EPA review and approval a protocol for operation of Corpus Christi FCCU 2 in a way that minimizes NOx emissions to the extent practicable and without creating a safety problem, interfering with conversion or processing rates, yield selectivity or otherwise exceeding previously established and complied with operating limits, provided such cannot be reasonably compensated for by adjustment(s) to other operating parameters ("NOx Minimization Protocol").

18. **NOx Minimization Demonstration at the Corpus Christi FCCU 2.** By no later than November 30, 2005, CITGO shall begin an 18-month demonstration ("Demonstration Period") of Corpus Christi FCCU 2 to establish long term (i.e., 365-day rolling average) and short term (e.g., 7-day or 24-hour rolling average) emission limits for NOx in ppmvd at 0% O_2. During the Demonstration Period, CITGO shall operate Corpus Christi FCCU 2 in accordance with the EPA-approved NOx Minimization Protocol.

19. **NOx Minimization Demonstration Report for Corpus Christi FCCU 2.** By no later than August 31, 2007, CITGO shall report the results of the demonstration ("NOx

Minimization Demonstration Report") to EPA. The NOx Minimization Demonstration Report shall include, at a minimum, the NOx and O_2 CEMS data recorded during the Demonstration Period and the following 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. Estimated percentage, and where available, actual percentage by volume of the FCCU feed that is hydrotreated;
h. FCCU feed hydrotreater reactor pressures and temperatures;
i. CO boiler firing rate and fuel type, if applicable;
j. CO boiler combustion temperature, if applicable;
k. Total Catalyst addition and catalyst circulation rates;
l. Conventional combustion promoter addition rates;
m. Hourly and daily volume percent oxygen in the regenerator fuel gas and at the point of CEMs measurement; and
n. 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.

Upon request by EPA, CITGO shall submit any additional, reasonably available data to EPA.

In the NOx Minimization Demonstration Report, CITGO shall propose a short term (i.e., 7-day and 24-hour rolling average) and a 365-day rolling average concentration-based (ppmvd) NOx emission limits, as measured at 0% O_2. CITGO shall comply with the emission limits it proposes for Corpus Christi FCCU 2 beginning immediately upon submission of the NOx Minimization Demonstration Report. CITGO shall continue to comply with these limits unless and until CITGO is required to comply with the emissions limits set by EPA pursuant to Paragraph 20.

20. **Establishing NOx Emission Limits for Corpus Christi FCCU 2.** EPA will use the data collected about the Corpus Christi FCCU 2 during the NOx Minimization Study and the Demonstration Period, as well as all other available and relevant information, to establish limits which can be met with a reasonable certainty of compliance but which shall be no lower than 20 ppmvd at 0% oxygen on a 365-day rolling average basis and no higher than 23 ppmvd at 0% oxygen on a 365-day rolling average basis for NOx emissions from Corpus Christi FCCU 2. Upon request by EPA, CITGO shall submit any additional, readily available data that EPA determines it needs to evaluate the demonstration. EPA will establish a short-term (*e.g.*, 24-hour or 7-day rolling average) and a 365-day rolling average concentration-based (ppmvd) NOx emission limit corrected to 0% oxygen, provided, however, that if EPA establishes a 365-day rolling average concentration-based NOx limit of 20 ppmvd at 0% oxygen, the short-term limit will then be 40 ppmvd at 0% oxygen (7-day rolling average). EPA will determine the limits based on: (i) the level of performance during the baseline, Minimization Study and Demonstration Period; (ii) a reasonable certainty of compliance; and (iii) any other available and relevant information. EPA will notify CITGO of its determination of the concentration-based NOx emissions limit and averaging times. EPA may establish alternative emissions limits to be applicable during alternative operating scenarios (e.g., during Hydrotreater Outages). CITGO shall immediately (or within thirty (30) days, if EPA's limit is more stringent than the limit proposed by CITGO) 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, CITGO shall comply with the emission limits it proposed under Paragraph 19. CITGO shall demonstrate compliance with its emission limits pursuant to Paragraph 31.

21. **Conversion of Corpus Christi FCCU 1 and the Lemont FCCU to Full Burn Operation.** CITGO shall no later than December 31, 2006 either convert FCCU 1 at the Corpus Christi East Refinery ("Corpus Christi FCCU 1") to Full Burn Operation, or accept and agree to comply with concentration based emission limits of 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average basis, both at 0% oxygen, at the Corpus Christi FCCU 1. CITGO shall no later than December 31, 2007 either convert the FCCU at the Lemont Refinery ("Lemont FCCU") to Full Burn Operation, or accept and agree to comply with concentration based emission limits of 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average basis, both at 0% oxygen, at the Lemont FCCU. As part of the conversion to Full Burn Operation, CITGO shall take into account changes that may be necessary to accommodate Low NOx Combustion Promoter at the maximum operating rate of each FCCU while controlling afterburn adequately and maintaining CO emissions at compliant levels.

22. **Installation of Low NOx Burners in Lemont CO Boiler.** By no later than December 31, 2007, CITGO shall install low NOx burners designed to achieve 0.060 lb/mmBTU HHV of NOx in the FCCU CO Boiler at the Lemont Refinery (assuming no air preheat and the use of natural gas) to reduce NOx emissions from combustion of auxiliary fuel.

23. **Use of Low NOx Combustion Promoters and NOx Reducing Catalyst Additives at the Corpus Christi 1, Lake Charles A, Lake Charles B, Lake Charles C and Lemont FCCUs: In General.** CITGO shall implement a program to reduce NOx emissions from the Corpus Christi 1, Lake Charles A, Lake Charles B, Lake Charles C and Lemont FCCUs

(collectively, "Corpus Christi 1, Lake Charles, and Lemont FCCUs"). As required under Section V.N. of this Consent Decree, CITGO shall apply for permits containing new NOx emission limits and will use CEMS to monitor for compliance with the emission limits.

24. **NOx Baseline Data for the Corpus Christi 1, Lake Charles, and Lemont FCCUs.** CITGO shall for each FCCU listed in the following table, no later than the dates specified in the table, submit to the Applicable Federal and State Agencies a report of at least twelve (12) months of baseline data, including baseline data for the baseline periods specified in the table:

FCCU	**Baseline Start**	**Baseline End**	**Report**
Corpus Christi 1	April 1, 2007	March 31, 2008	June 30, 2008
Lake Charles A	October 1, 2005	September 30, 2006	December 31, 2006
Lake Charles B	October 1, 2005	September 30, 2006	December 31, 2006
Lake Charles C	October 1, 2005	September 30, 2006	December 31, 2006
Lemont	April 1, 2008	March 31, 2009	June 30, 2009

The baseline data shall include at a minimum, the data set forth in Paragraph 19.

25. [Intentionally Left Blank]

26. **Low-NOx Combustion Promoter - Short-Term Trials for the Corpus Christi 1, Lake Charles, and Lemont FCCUs.**

a. Identification and Selection of Low NOx Combustion Promoters for Trial Use. By the following dates, CITGO shall select and submit for EPA approval at least two commercially available Low NOx Combustion Promoters that CITGO proposes to use for later short-term trials at the Corpus Christi 1, Lake Charles, and Lemont FCCUs and shall submit a protocol for conducting the trials by the following dates:

Corpus Christi 1:	December 31, 2007
Lake Charles A:	June 30, 2006
Lake Charles B:	June 30, 2006
Lake Charles C:	June 30, 2006
Lemont:	December 31, 2008

CITGO shall propose use of at least two Low NOx Combustion Promoters that are likely to perform the best at reducing NOx emissions in each FCCU. EPA will base its approval or disapproval on its assessment of the performance of the proposed Promoters in other FCCUs and the similarity of those FCCUs to CITGO's FCCUs, with the objective of testing Low NOx Combustion Promoters likely to have the best performance in reducing NOx emissions while adequately combusting CO in the FCCU regenerator. If EPA objects to one or more of the proposed Low NOx Combustion Promoters, EPA will explain the basis of its objections in writing. In the event that CITGO submits less than two approvable Promoters, EPA shall identify and by that identification approve the use of other Low NOx Combustion Promoters by CITGO.

b. Minimization of Use of Conventional Pt-Based Combustion Promoter. CITGO shall commence and complete a program of minimization of use of conventional Platinum-based ("Pt-based") combustion promoter to the amount necessary to adequately control afterburn. CITGO shall complete this program in accordance with the protocol set forth in Appendix D by the following dates for each of the following FCCUs:

FCCU	**Commence Date**	**Complete Date**
Corpus Christi 1	April 1, 2008	June 30, 2008
Lake Charles A	October 1, 2006	December 31, 2006
Lake Charles B	October 1, 2006	December 31, 2006
Lake Charles C	October 1, 2006	December 31, 2006
Lemont	April 1, 2009	June 30, 2009

c. Short-Term Trials of Low NOx Combustion Promoters. CITGO shall conduct trials of at least two EPA-approved Low NOx Combustion Promoters that were selected and approved under Subparagraph 26a, and such other Low NOx Combustion Promoters as CITGO may elect, for each of the following FCCUs in accordance with Appendix D by the following dates:

FCCU	**Commence Date**
Corpus Christi 1	July 1, 2008
Lake Charles A	January 1, 2007
Lake Charles B	January 1, 2007
Lake Charles C	January 1, 2007
Lemont	July 1, 2009

d. Report on Results of Short-Term Trials and Minimization Program for Conventional Pt-Based Combustion Promoters. CITGO shall submit a report to EPA that describes the results of the minimization of use of conventional Pt-based combustion promoter and the performance of each Low NOx Combustion Promoter that was tested by the following dates for each of the following FCCUs:

FCCU	**Report Date**
Corpus Christi 1	December 31, 2008
Lake Charles A	June 30, 2007
Lake Charles B	June 30, 2007
Lake Charles C	June 30, 2007
Lemont	December 31, 2009

In the report, CITGO shall propose to use the best performing Combustion Promoter, as demonstrated and explained by CITGO (*e.g.* by percentage of NOx emissions reduced and the concentration to which NO_x emissions were reduced in the trials without creating a safety problem or limiting conversion rates, processing rates or yield selectivity).

e. EPA Approval of Combustion Promoters. For each of the five FCCUs subject to this Paragraph, EPA will either approve the Low NOx Combustion Promoter proposed by CITGO, approve another Low NOx Combustion Promoter that was tested by CITGO, or approve the use of a conventional Pt-based promoter based on the criteria in Appendix D. If EPA objects to CITGO's selection of Low NOx Combustion Promoter or conventional Pt-based promoter, EPA will explain the basis of its objections in writing. Upon request by EPA, CITGO shall submit any additional, reasonably available data that EPA determines it needs to evaluate the trials.

CITGO shall use the approved Low NOx Combustion Promoter, or if applicable, a conventional Pt-based combustion promoter under the terms of Appendix D.

f. Discontinuance of Low NOx Combustion Promoters. CITGO may, upon EPA approval, discontinue use of a Low NOx Combustion Promoter at a particular FCCU if CITGO demonstrates that, as to that particular FCCU, CITGO has adjusted other parameters and the Promoter being used does not adequately control afterburn and/or causes CO emissions to approach or exceed applicable limits and/or exceeds safe operation limits or equipment design limits. Notwithstanding the foregoing, CITGO shall not be required to adjust operating parameters in a way that would create a safety problem or limit conversion rates, processing rates or yield selectivity.

g. Use of Conventional Pt-Based Combustion Promoter. CITGO may use conventional Pt-based combustion promoter on an intermittent basis during the short-term trials under this Paragraph, and the short-term trials, optimization studies and demonstration periods under Paragraphs 27, 28, and 29, as needed to avoid unsafe operation of the FCCU regenerator and to comply with CO emission limits. CITGO shall undertake all reasonable measures and/or adjust operating parameters with a goal of eliminating such use. Notwithstanding the foregoing, CITGO shall not be required to adjust operating parameters in a way that would create a safety problem or limit conversion rates, processing rates or yield selectivity.

27. **NOx Reducing Catalyst Additives - Short-Term Trials at the Corpus Christi 1, Lake Charles and Lemont FCCUs.**

a. Identification and Selection of NOx Reducing Catalyst Additives for Trial Use. CITGO shall select and submit for EPA approval at least two commercially available NOx

Reducing Catalyst Additives that CITGO proposes to use for later short-term trials at the Corpus Christi 1, Lake Charles and Lemont FCCUs and shall submit a protocol for conducting the trials by the following dates:

FCCU	**Report Date**
Corpus Christi 1	December 31, 2009
Lake Charles A	June 30, 2008
Lake Charles B	December 31, 2006
Lake Charles C	December 31, 2006
Lemont	June 30, 2009

CITGO shall propose use of at least two NOx Reducing Catalyst Additives that are likely to perform the best at reducing NOx emissions in each FCCU. EPA will base its approval or disapproval on its assessment of the performance of the proposed Additives in other FCCUs and the similarity of those FCCUs to CITGO's FCCUs, with the objective of testing NOx Reducing Catalyst Additives likely to have the best performance in reducing NOx emissions. If EPA objects to one or more of the proposed NOx Reducing Catalyst Additives, EPA will explain the basis of its objections in writing. In the event that CITGO submits less than two approvable NOx Reducing Catalyst Additives, EPA shall identify and by that identification approve the use of other NOx Reducing Catalyst Additives by CITGO.

b. Short-Term Trials of NOx Reducing Catalyst Additives. CITGO shall conduct trials of at least two EPA-approved NOx Reducing Catalyst Additives, and such other NOx Reducing Catalyst Additives as CITGO may elect, for each of the following FCCUs in accordance with the protocol approved pursuant to Subparagraph 27.a as soon as practicable, but by no later than the following dates:

FCCU	**Commence Date**	**Complete Date**
Corpus Christi 1	July 1, 2010	December 31, 2010
Lake Charles A	January 1, 2009	June 30, 2009
Lake Charles B	July 1, 2007	December 31, 2007
Lake Charles C	July 1, 2007	December 31, 2007
Lemont	January 1, 2010	June 30, 2010

c. Report on the Performance of NOx Reducing Catalyst Additives. CITGO shall submit a report to EPA that describes the performance of each NOx Reducing Catalyst Additive that was tested no later than the following dates for each of the following FCCUs:

FCCU	**Report Date**
Corpus Christi 1	February 28, 2011
Lake Charles A	August 31, 2009
Lake Charles B	February 28, 2008
Lake Charles C	February 28, 2008
Lemont	August 31, 2010

In the report, CITGO shall propose to use the best performing NOx Reducing Catalyst Additive, as demonstrated and explained by CITGO (*e.g.* by percentage of NOx emissions reduced and the concentration to which NOx emissions were reduced in the trials without creating a safety problem or limiting conversion rates, processing rates or yield selectivity, provided such cannot reasonably be compensated for by adjustment(s) to other operating parameters).

d. EPA Approval of the NOx Reducing Catalyst Additives. EPA will either approve the NOx Reducing Catalyst Additive proposed by CITGO or approve another NOx Reducing Catalyst Additive that was tested. Upon request by EPA, CITGO shall submit any additional, reasonably available data that EPA determines it needs to evaluate the trials. If EPA objects to CITGO's selection of a NOx Reducing Catalyst Additive, EPA will explain the basis of its objections in writing. CITGO shall use the approved NOx Reducing Catalyst Additive selected pursuant to this Paragraph in the Optimization Studies and Demonstration Periods required pursuant to Paragraphs 28 and 29.

28. **NOx Reducing Catalyst Additives - Optimization Studies at the Corpus Christi 1, Lake Charles and Lemont FCCUs.**

a. Optimization Study Protocol. CITGO shall submit, for EPA approval, a proposed protocol consistent with the requirements of Appendix D for optimization studies to establish the optimized NOx Reducing Catalyst Additive and combustion promoter addition rates by the following dates for each of the following FCCUs:

FCCU	Deadline
Corpus Christi 1	February 28, 2011
Lake Charles A	August 31, 2009
Lake Charles B	February 28, 2008
Lake Charles C	February 28, 2008
Lemont	August 31, 2010

The protocol shall include identification of the NOx Reducing Catalyst Additive, methods to calculate effectiveness, cost effectiveness, methods for base loading, and percent NOx Reducing Catalyst Additive used at each increment tested.

b. Optimization Studies. CITGO shall commence and complete the optimization study of each NOx Reducing Catalyst Additive and combustion promoter selected under Paragraphs 27.d and 26.e in accordance with the approved protocol and with Appendix D by the following dates for each of the following FCCUs:

FCCU	**Commence Date**	**Complete Date**
Corpus Christi 1	May 1, 2011	October 31, 2011
Lake Charles A	November 1, 2009	April 31, 2010
Lake Charles B	May 1, 2008	October 31, 2008
Lake Charles C	May 1, 2008	October 31, 2008
Lemont	November 1, 2010	April 30, 2011

c. Optimization Study Reports. By the following dates for each of the FCCUs subject to this Paragraph, CITGO shall report the results of the optimization studies and propose, for EPA approval, optimized addition rates of the NOx Reducing Catalyst Additives and combustion promoters to be used for the demonstration period:

FCCU	**Deadline**
Corpus Christi 1	December 31, 2011
Lake Charles A	June 30, 2010
Lake Charles B	December 31, 2008
Lake Charles C	December 31, 2008
Lemont	June 30, 2011

Upon request by EPA, CITGO shall submit any additional, reasonably available data that EPA determines it needs to evaluate the optimization study.

CITGO shall include in its report a description of any model CITGO used to predict uncontrolled NOx concentration and mass emission rate unless CITGO agrees to add NOx Reducing Catalyst Additive at 2.0 weight % as the optimized addition rate. Such description shall describe how the model was developed, which parameters were considered, why parameters were eliminated, efforts and results of model validation, the statistical methods used to arrive at the equation to predict uncontrolled NO_X concentration and mass emission rate and all data considered in developing the model on a daily average basis. Upon request by EPA, CITGO shall submit any additional, reasonably available data that EPA determines it needs to evaluate the model.

d. <u>EPA Approval of the Optimized Addition Rates of the NOx Reducing Catalyst Additives and Low NOx Combustion Promoters</u>. EPA will either approve or disapprove each of the optimized addition rates proposed by CITGO. CITGO will not be required to add increasing increments of NOx Reducing Catalyst Additive beyond an additive rate that results in any of the following:

i. The FCCU meets 20 ppmvd NOx at 0% O_2 on a 365-day rolling average, provided CITGO agrees to accept limits of 20 ppmvd NOx at 0% O_2 on a 365-day rolling average basis at the conclusion of the Demonstration Period;

ii Incremental NOx Reducing Factor < 1.8 lb NOx/lb additive;

iii. Total cost of the NOx Reducing Catalyst Additive > $10,000/ton NOx removed; or

iv. FCCU is operating at 2.0 Weight % NOx Reducing Catalyst Additive.

If EPA disapproves the proposed optimized addition rate for either the NOx Reducing Catalyst Additives or Low NOx Combustion Promoters, EPA will explain the basis of its disapproval in writing, and will specify the approved optimized addition rate.

29. **<u>NOx Reducing Catalyst Additives - Demonstration Periods for the Corpus Christi 1, Lake Charles and Lemont FCCUs</u>.**

a. <u>Demonstration Period</u>. CITGO shall commence and complete demonstration of the NOx Reducing Catalyst Additive and the Low Nox Combustion Promoter at the final optimized addition rates selected in Paragraph 28.d, or if applicable, a conventional Pt-based combustion promoter under the terms of Appendix D, by the following dates for each of the following FCCUs:

FCCU	Commence Date	Complete Date
Corpus Christi 1	January 1, 2012	June 30, 2013
Lake Charles A	July 1, 2010	December 31, 2011
Lake Charles B	January 1, 2009	June 30, 2010
Lake Charles C	January 1, 2009	June 30, 2010
Lemont	July 1, 2011	December 31, 2012

For Corpus Christi FCCU 1 and Lake Charles FCCU A, the NOx Reducing Catalyst Additive, Low NOx combustion Promoter and SO_2 Reducing Catalyst Additive demonstrations shall occur simultaneously. During the demonstration period, CITGO shall add NOx Reducing Catalyst Additive and operate the FCCUs, CO Boilers (where they exist) and FCCU feed hydrotreaters (where they exist) in a manner that minimizes NOx emissions to the extent practicable without creating a safety problem or limiting conversion rates, processing rates or yield selectivity, provided such cannot be reasonably compensated for by adjustment(s) to other operating parameters.

b. NOx Reducing Catalyst Additive Performance Demonstration Report ("NOx Additive Demonstration Report"). CITGO will report the results of the demonstration ("NOx Additive Demonstration Report") to EPA by the following dates for each of the following FCCUs:

FCCU	**Report Date**
Corpus Christi 1	September 30, 2013
Lake Charles A	March 31, 2012
Lake Charles B	September 30, 2010
Lake Charles C	September 30, 2010
Lemont	March 31, 2013

Each NOx Additive Demonstration Report shall include, at a minimum, the NOx and O_2 CEMS data recorded during the Demonstration Period and all of the applicable parameters under Paragraph 19 for the Demonstration Period. In each NOx Additive Demonstration Report, CITGO shall propose a short-term (i.e., 24-hour and 7-day rolling average) and a long-term (365-day rolling average) concentration-based (ppmvd) NOx emission limit, both as measured at 0% O_2, for the Corpus Christi 1, Lake Charles, and Lemont FCCUs. CITGO shall comply with the emission limits it proposes for each of these FCCUs beginning immediately upon submission of the NOx Additive Demonstration Report for that FCCU. CITGO shall continue to comply with these limits unless and until CITGO is required to comply with the emissions limits set by EPA pursuant to Paragraph 30. Upon request by EPA, CITGO shall submit any additional, reasonably available data that EPA determines it needs to evaluate the demonstration.

30. **Establishing NOx Emissions Limits at the Corpus Christi 1, Lake Charles and Lemont FCCUs**. EPA will use the data collected during the baseline period, the Optimization Period, and the Demonstration Period, as well as all other available and relevant information, to establish limits for NOx emissions from the Corpus Christi 1, Lake Charles and Lemont FCCUs.

EPA will establish short-term (e.g., 24-hour or 7-day rolling average) and a 365-day rolling average concentration-based (ppmvd) NOx emission limits, both corrected to 0% oxygen, which limits can be met by CITGO with a reasonable certainty of compliance. EPA will determine the limits based on: (i) the level of performance during the baseline, Short-Term Trials, and Optimization and Demonstration periods; (ii) a reasonable certainty of compliance; and (iii) any other available and relevant information. EPA will notify CITGO of its determination of the concentration-based NOx emissions limit and averaging times for each FCCU. EPA may establish alternative emissions limits to be applicable during alternative operating scenarios (e.g., during Hydrotreater Outages). CITGO shall immediately (or within thirty (30) days, if EPA's limit is more stringent than the limit proposed by CITGO) 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, CITGO shall add additives in the manner and amount applicable during the Demonstration Period (in lieu of complying with the EPA limits).

30A. **Emission Limit Option.** CITGO may, at any time up to and including its proposing emission limits under Paragraphs 19 and/or 29, accept and agree to comply immediately with concentration based emission limits of 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average basis, both at 0% oxygen, for a particular FCCU. In such circumstances, CITGO shall be absolved of any remaining obligations for that FCCU under Paragraphs 13 through 30 of this Consent Decree.

31. **Demonstrating Compliance with FCCU NOx Emission Limits for all Covered FCCUs.** CITGO shall use NOx and O_2 CEMS to monitor performance and to report compliance with the terms and conditions of this Consent Decree. CITGO shall make CEMS data available to EPA as soon as practicable following an EPA request for such data.

B. SO_2 EMISSIONS REDUCTIONS FROM FCCUs

32. **General.** CITGO shall implement a program to reduce SO_2 emissions from the Covered FCCUs. CITGO shall apply for permits containing new SO_2 emission limits established under this Consent Decree, and CITGO will monitor compliance with the emission limits through the use of CEMS.

33. **Installation of Wet Gas Scrubbers on the Lake Charles B, Lake Charles C, and Lemont FCCUs.** CITGO shall install and commence operation of a Wet Gas Scrubber ("WGS") and comply with a SO_2 emission limit 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 for each of the following FCCUs by the dates specified:

FCCU	Deadline
Lake Charles FCCU B	December 31, 2006
Lake Charles FCCU C	December 31, 2007
Lemont FCCU	December 31, 2007

34. **Use of SO_2 Reducing Additives at the Corpus Christi 1, Corpus Christi 2, and Lake Charles A FCCUs: In General.** As described below, CITGO shall implement a program to reduce SO_2 emissions and establish lower FCCU SO_2 emission limits at the Corpus Christi 1, Corpus Christi 2, and Lake Charles A FCCUs (collectively "Corpus Christi and Lake Charles A FCCUs"), by using SO_2 Reducing Catalyst Additives.

35. **SO_2 Baseline Data for the Corpus Christi and Lake Charles A FCCUs.** CITGO shall for each FCCU listed in the following table, no later than the dates specified in the table, submit to the Applicable Federal and State Agencies a report of at least twelve (12) months of baseline data, including baseline data for the baseline periods specified in the table:

FCCU	Baseline Start	Baseline End	Report
Corpus Christi 1	April 1, 2007	March 31, 2008	June 30, 2008
Corpus Christi 2	October 1, 2005	September 30, 2006	December 31, 2006
Lake Charles A	October 1, 2005	September 30, 2006	December 31, 2006

The baseline data shall include at a minimum, the data set forth in Paragraph 19.

36. [Intentionally Left Blank].

37. **SO_2 Reducing Catalyst Additives - Short-Term Trials for the Corpus Christi and Lake Charles A FCCUs.**

a. Identification and Selection of SO_2 Reducing Catalyst Additives for Trial Use. By the following dates, CITGO shall select and submit for EPA approval at least two commercially available SO_2 Reducing Catalyst Additives that CITGO proposes to use for short-term trials at the Corpus Christi and Lake Charles A FCCUs:

Corpus Christi 1	June 30, 2008
Corpus Christi 2	May 31, 2006
Lake Charles A	December 31, 2006

CITGO shall propose use of at least two SO_2 Reducing Catalyst Additives that are likely to perform the best at reducing SO_2 emissions in each FCCU. EPA will base its approval or disapproval on its assessment of the performance of the proposed Additives in other FCCUs and the similarity of those FCCUs to CITGO's FCCUs, 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, EPA will explain the basis of its objections in writing. In the event that CITGO submits less than two approvable Additives, EPA shall identify and by that identification approve the use of other SO2 Reducing Catalyst Additives by CITGO.

b. Short-Term Trials of SO_2 Reducing Catalyst Additives. CITGO shall conduct trials of at least two EPA-approved SO_2 Reducing Catalyst Additives selected under Subparagraph 37a, and such other SO2 Reducing Catalyst Additives as CITGO may elect, for each of the following FCCUs in accordance with Appendix D by the following dates:

FCCU	Commence Date	Complete Date
Corpus Christi 1	January 1, 2009	June 30, 2009
Corpus Christi 2	January 1, 2007	June 30, 2007
Lake Charles A	July 1, 2007	December 31, 2007

c. Report on the Performance of the SO_2 Reducing Catalyst Additives. CITGO shall submit a report to EPA that describes the performance of each SO_2 Reducing Catalyst Additive that was tested under Subparagraph 37b by the following dates for each of the following FCCUs:

FCCU	Report Date
Corpus Christi 1	August 31, 2009
Corpus Christi 2	August 31, 2007
Lake Charles A	February 28, 2008

In the report, CITGO shall propose to use the best performing additive as demonstrated and explained by CITGO (e.g., by percentage of SO_2 emissions reduced and the concentration to which SO_2 emissions were reduced in the trials without creating a safety problem or limiting conversion rates, processing rates or yield selectivity, provided such cannot reasonably be compensated for by adjustment(s) to other operating parameters).

d. EPA Approval of the SO_2 Reducing Catalyst Additives. EPA will either approve the SO_2 Reducing Catalyst Additive proposed by CITGO or approve another additive that was tested. If EPA objects to CITGO's selection of SO_2 Reducing Catalyst Additive, EPA will explain the basis of its objections in writing. Upon request by EPA, CITGO shall submit any additional, reasonably available data that EPA determines it needs to evaluate the trials. CITGO shall use the SO_2 Reducing Catalyst Additive selected pursuant to this Paragraph in the Optimization Studies and Demonstration Periods required pursuant to Paragraphs 38 and 39.

38. **SO_2 Reducing Catalyst Additives - Optimization Studies at the Corpus Christi and Lake Charles A FCCUs.**

a. Optimization Study Protocol. CITGO shall submit, for EPA approval, a proposed protocol consistent with the requirements of Appendix D for optimization studies to establish the optimized SO_2 Reducing Catalyst Additive addition rates by the following dates for each of the following FCCUs:

Corpus Christi 1	August 31, 2009
Corpus Christi 2	August 31, 2007
Lake Charles A	February 28, 2008

The protocol shall include identification of the SO_2 Reducing Catalyst Additive, methods to calculate effectiveness, cost effectiveness, methods for base loading, and percent SO_2 Reducing Catalyst Additive used at each increment tested.

b. Optimization Studies. CITGO shall commence and complete the optimization study of each EPA-approved SO_2 Reducing Catalyst Additive in accordance with the approved protocol and Appendix D by the following dates for each of the following FCCUs:

FCCU	Commence Date	Complete Date
Corpus Christi 1	November 1, 2009	April 30, 2010
Corpus Christi 2	November 1, 2007	April 30, 2008
Lake Charles A	May 1, 2008	October 31, 2008

c. Optimization Study Reports. By the following dates for each of the FCCUs subject to this Paragraph, CITGO shall report the results of the optimization study and propose, for EPA approval, an optimized addition rate of SO_2 Reducing Catalyst Additive to be used for the demonstration period:

Corpus Christi 1	June 30, 2010
Corpus Christi 2	June 30, 2008
Lake Charles A	December 31, 2008

CITGO shall include in its report a description of any model CITGO used to predict uncontrolled SO2 concentration and mass emission rate unless CITGO agrees to add SO2 Reducing Catalyst Additive at 10.0 weight % as the optimized addition rate. Such description shall describe how the model was developed, which parameters were considered, why parameters were eliminated, efforts and results of model validation, the statistical methods used to arrive at the equation to predict uncontrolled SO2 concentration and mass emission rate and all data considered in developing the model on a daily average basis. Upon request by EPA, CITGO shall submit any additional, reasonably available data that EPA determines it needs to evaluate the model or the optimization study. CITGO shall use the approved SO_2 Reducing Catalyst Additive rate during the Demonstration Periods required pursuant to Paragraph 39.

d. EPA Approval of the Optimized Addition Rate of the SO_2 Reducing Catalyst Additive. EPA will either approve or disapprove the optimized addition rate proposed by CITGO. CITGO will not be required to add SO_2 Reducing Catalyst Additive beyond an additive rate that results in any of the following:

i. The FCCU meets 25 ppmvd SO_2 at $0\%O_2$ on a 365-day rolling average, provided CITGO agrees to accept limits of 25 ppmvd SO_2 at $0\%O_2$ on a 365-day rolling average basis at the conclusion of the Demonstration Period;

ii. Incremental SO_2 Pick-up Factor < 2.0 lb SO_2/lb additive; or

iii. FCCU is operating at 10.0 Weight % SO_2 reducing catalyst additive.

If EPA disapproves the proposed optimized addition rate for the SO_2 Reducing Catalyst Additive, EPA will explain the basis of its disapproval in writing, and will specify the approved optimized addition rate.

39. **SO_2 Reducing Catalyst Additives - Demonstration Periods for the Corpus Christi and Lake Charles A FCCUs**:

a. Demonstration Period. CITGO shall commence and complete demonstration of the final SO_2 Reducing Catalyst Additive at the optimized addition rates selected under Paragraph 38.d by the following dates for each of the following FCCUs:

FCCU	Commence Date	Complete Date
Corpus Christi 1	January 1, 2012	June 30, 2013
Corpus Christi 2	July 1, 2008	December 31, 2009
Lake Charles A	July 1, 2010	December 31, 2011

For Corpus Christi FCCU 1 and Lake Charles FCCU A, the NOx Reducing Catalyst Additive, Low NOx Combustion Promoter, and SO_2 Reducing Catalyst Additive demonstrations shall occur simultaneously. During the demonstration for the Lake Charles FCCU A, CITGO shall hydrotreat all of the FCCU feed to the Lake Charles FCCU A. During the demonstration period, CITGO shall add SO_2 Reducing Catalyst Additive and operate the FCCUs, CO Boilers (where they exist) and FCCU feed hydrotreaters (where they exist) in a manner that minimizes SO_2 emissions to the extent practicable without creating a safety problem or limiting conversion rates, processing rates or yield selectivity, provided such cannot be reasonably compensated for by adjustment(s) to other operating parameters.

b. SO_2 Reducing Catalyst Additive Performance Demonstration Report ("SO_2 Additive Demonstration Report"). CITGO will report the results of the demonstration ("SO_2 Additive Demonstration Report") to EPA by the following dates for each of the following FCCUs:

FCCU	Report Date
Corpus Christi 1	September 30, 2013
Corpus Christi 2	March 31, 2010
Lake Charles A	March 31, 2012

Each SO_2 Additive Demonstration Report shall include, at a minimum, the SO_2 and O_2 CEMS data recorded during the Demonstration Period and all of the applicable parameters under Paragraph 19 for the Demonstration Period. In each SO_2 Additive Demonstration Report, CITGO shall propose 7-day rolling average and 365-day rolling average concentration-based (ppmvd) SO_2 emission limits as measured at 0% O_2 for the Corpus Christi and Lake Charles A FCCUs. CITGO shall comply with the emission limits it proposes for each FCCU beginning immediately upon submission of the SO_2 Additive Demonstration Report for that FCCU. CITGO shall continue to comply with these limits unless and until it is required to comply with the emissions limits set by EPA pursuant to Paragraph 40. Upon request by EPA, CITGO shall submit any additional, reasonably available data that EPA determines it needs to evaluate the demonstration.

40. **Establishing SO_2 Emissions Limits for the Corpus Christi and Lake Charles A FCCUs.** EPA will use the data collected during the baseline period, the Short-Term Trials, the Optimization Period, and the Demonstration Period, as well as all other available and relevant information, to establish limits for SO_2 emissions from the Corpus Christi and Lake Charles A FCCUs. EPA will establish a 7-day rolling average and a 365-day rolling average concentration-based (ppmvd) SO_2 emission limit corrected to 0% oxygen, which limits can be met with a reasonable certainty of compliance. EPA will determine the limits based on: (i) the level of performance during the baseline, Optimization and Demonstration periods; (ii) a reasonable certainty of compliance; and (iii) any other available and relevant information. EPA will notify CITGO of its determination of the concentration-based SO_2 emissions limit and averaging times for each FCCU. EPA may establish alternative emissions limits to be applicable during alternative operating scenarios, including, for example, during Hydrotreater Outages. CITGO shall immediately (or within thirty (30) days, if EPA's limit is more stringent than the limit proposed by CITGO) 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, CITGO shall add additives in the manner and amount applicable during the Demonstration Period (in lieu of meeting the EPA limits).

40A. **Emission Limit Option.** CITGO may, at any time up to and including its proposing emission limits under Paragraph 39, accept and agree to comply immediately with concentration based 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 a particular FCCU. In such circumstances, CITGO shall be absolved of any remaining obligations for that FCCU under Paragraphs 34 through 40 of this Consent Decree.

41. **Demonstrating Compliance with FCCU SO_2 Emission Limits for all Covered FCCUs.** Beginning on the dates set forth in Paragraph 12, CITGO shall use SO_2 and O_2 CEMS to monitor performance and to report compliance with the terms and conditions of this Consent Decree. CITGO shall make CEMS data available to EPA as soon as practicable following an EPA request for such data.

42. **Hydrotreater Outages**. By no later than February 28, 2005, CITGO shall submit to EPA for its approval a plan to minimize SO_2 and NOx emissions from its Corpus Christi and Lake Charles FCCUs during Hydrotreater Outages. CITGO shall comply with the plan at all times during a hydrotreater outage including periods of startup, shutdown, and Malfunction of the hydrotreater. The short term emission limits for SO2 and NOx established for the FCCUs as provided in this Consent Decree shall not apply during periods of Hydrotreater Outages at the Corpus Christi and/or Lake Charles Refineries, provided that CITGO operates the units (including associated air pollution control equipment) in a manner consistent with good air pollution control practices during such periods. Following the installation of a wet gas scrubber at an FCCU covered by this Paragraph, this Paragraph shall no longer apply to that FCCU for SO2.

C. PM EMISSIONS REDUCTIONS FROM FCCUs.

43. **General**. CITGO shall control and further reduce particulate matter ("PM") emissions from the Covered FCCUs by the installation and operation of WGSs and/or third stage separators ("TSS") or continued operation of electrostatic precipitators ("ESPs").

44. **PSD Emission Limits for Lake Charles and Lemont FCCUs**

a. CITGO will install and commence operation of a WGS designed to achieve an emission limit of 0.5 pounds of PM per 1000 pounds of coke burned on a 3-hour average basis for the following FCCUs by no later than the dates set forth below for each FCCU:

Lake Charles FCCU B	December 31, 2006
Lake Charles FCCU C	December 31, 2007
Lemont FCCU	December 31, 2007

b. Unless CITGO agrees to accept an emission limit of 0.5 pounds of PM per 1000 pounds of coke burned on a 3-hour average basis, EPA will use the data collected under Paragraph 47, as well as other, available and relevant information, to establish PM emission limits for each FCCU which can be met with a reasonable certainty of compliance but which shall be no lower than 0.5 pounds of PM per 1000 pounds of coke burned on a 3-hour average basis. EPA will determine the limits based on : (i) the level of performance during the Performance Test(s); (ii) a reasonable certainty of compliance; and (iii) any other available and relevant information. EPA will notify CITGO of its determination of an appropriate emission limit or limits. During any dispute under this Paragraph, CITGO shall continue to operate the WGSs required under this Paragraph in a manner consistent with good air pollution control practices in lieu of meeting the EPA-established limit under this Paragraph.

45. **<u>PSD Emission Limits at the Corpus Christi 1, Corpus Christi 2, and Lake Charles A FCCUs</u>**. At any time during the life of the Consent Decree, CITGO may accept a PM emission limit of 0.5 pounds of PM per 1000 pounds of coke burned on a 3-hour average basis for the Corpus Christi 1, Corpus Christi 2, and/or Lake Charles A FCCUs that is/are then reflected in a federally enforceable, non-Title V permit.

46. **<u>NSPS PM Emission Limits for the Covered FCCUs</u>.** In accordance with NSPS regulations at 40 CFR, Part 60, Subpart J, CITGO shall comply with an emission limit of 1.0 pounds of PM per 1000 pounds of coke burned on a 3-hour average basis for all of the Covered FCCUs by the following dates:

Corpus Christi #1	December 31, 2006
Corpus Christi #2	April 30, 2005
Lake Charles A	March 31, 2010
Lake Charles B	December 31, 2006
Lake Charles C	December 31, 2007
Lemont	December 31, 2007

The deadlines imposed above shall not affect CITGO's obligation to comply with the MACT 2 (40 C.F.R. § 63.640) in a timely manner.

47. **<u>PM Testing for the Covered FCCUs</u>.** CITGO shall follow the stack test protocol specified in 40 C.F.R. § 60.106(b)(2) using EPA Reference Method 5B or 5F to measure PM emissions from the Covered FCCUs. CITGO shall propose and submit the stack test protocol for approval to EPA by no later than three (3) months after a PM limit becomes effective for a particular Covered FCCU. CITGO shall conduct the first stack test no later than three (3) months after EPA approves the stack test protocol. Until termination of the Consent Decree, CITGO

shall conduct annual PM stack tests at each Covered FCCU. Upon demonstrating through at least three (3) annual tests that the PM limits are not being exceeded at a particular Covered FCCU, CITGO may request EPA approval to conduct tests less frequently than annually at that Covered FCCU. Such approval will not be unreasonably withheld.

D. <u>CO EMISSIONS REDUCTIONS FROM FCCUs</u>

48. **<u>CO Emission Limits for the Corpus Christi 2, Lake Charles A, Lake Charles B, Lake Charles C, and Lemont FCCUs</u>.** CITGO shall comply with emission limits of 100 ppmvd CO corrected to 0% O_2 on a 365-day rolling average basis and 500 ppmvd CO corrected to 0% O_2 on a 1-hour average basis for the Corpus Christi 2 and Lemont FCCUs by no later than the Date of Entry of the Consent Decree. CITGO shall comply with the emission limits pursuant to this Paragraph for the Lake Charles A, Lake Charles B and Lake Charles C FCCUs by no later than the date of installation of CO CEMS pursuant to Paragraph 12 of this Consent Decree.

49. **<u>CO Emission Limits for the Corpus Christi 1 FCCU</u>.** CITGO shall comply with an emission limit of 500 ppmvd CO corrected to 0% O_2 on a 1- hour average basis for the Corpus Christi 1 FCCU by no later than the date of installation of CO CEMs pursuant to Paragraph 12 of the Consent Decree.

50. **<u>Demonstrating Compliance with CO Emissions Limits at the Covered FCCUs</u>.** Beginning on the dates set forth in Paragraph 12, CITGO shall use CO and O_2 CEMS to monitor emissions and to report compliance with the terms and conditions of this Consent Decree. CITGO shall make CEMS data available to EPA as soon as practicable following an EPA request for such data.

E. NSPS APPLICABILITY TO FCCU REGENERATORS

51. Each of CITGO's FCCU regenerators at the Corpus Christi, Lake Charles, and Lemont 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 all of the requirements of NSPS Subparts A and J for each pollutant. CITGO shall comply with the requirements of NSPS Subparts A and J for its FCCU regenerators for SO_2, PM and CO by the following dates:

	SO_2	PM	CO
Corpus Christi FCCU 1	January 1, 2012	December 31, 2006	April 1, 2007
Corpus Christi FCCU 2	July 1, 2008	April 30, 2005	Date of Entry
Lake Charles FCCU A	January 1, 2010	March 31, 2010	October 1, 2005
Lake Charles FCCU B	December 31, 2006	December 31, 2006	October 1, 2005
Lake Charles FCCU C	December 31, 2007	December 31, 2007	October 1, 2005
Lemont	December 31, 2007	December 31, 2007	Date of Entry

F. NOx EMISSIONS REDUCTIONS FROM HEATERS AND BOILERS

52. **General**. CITGO shall implement a program to reduce NOx emissions from the heaters and boilers at the Covered Refineries through the installation of NOx controls or the shut down of units and by applying for and accepting emission limits in a permit for the units controlled to meet the requirements of Paragraphs 54 and 58. CITGO will monitor compliance

with the emission limits through the use of CEMS, PEMS, or stack tests as described in more detail below.

53. **Identification of Qualifying Controls.** CITGO shall select one or any combination of the following "Qualifying Controls" to satisfy the requirements of Paragraphs 54 and 58:

a. SCR or SNCR;

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

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

d. permanent shutdown of a heater or boiler with revocation of its operating permit;

e. If Current Generation or Next Generation Ultra-Low NOx Burners are technologically infeasible for a cylindrical heater and/or boiler, CITGO may propose an alternative single burner technology which CITGO demonstrates to EPA's satisfaction will reduce NOx emissions to 0.055 lbs per mmBTU or lower; or

f. in the case of the compressor engines at the Corpus Christi East Refinery, catalytic converters that are designed to achieve 2 grams of NOx per Brake Horsepower/ Hour (Bhp/Hr).

54. **Installation of Qualifying Controls.** On or before June 30, 2011, CITGO shall use Qualifying Controls to reduce NOx emissions from the heaters and boilers listed in Appendix C (excluding those at the Paulsboro and Savannah Refineries) by at least 50% of the revised

baseline identified under Paragraph 55A. For example and based on the baseline identified in Paragraph 55, this amount would be 4,949 tons per year. The emission reductions required by this Paragraph 54 shall be demonstrated by satisfying the following inequality:

$$\sum_{i=1}^{n} \left[(E_{actual})_i - (E_{allowable})_i \right] \geq XXXX$$

Where:

$(E_{allowable})_i$	=	[(The permitted allowable pounds of NOx per million BTU for heater or boiler i)/(2000 pounds per ton)] x [(the lower of permitted or maximum heat input rate capacity in million BTU per hour for heater or boiler 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 C for heater or boiler (unless prior actual emissions exceed allowable emissions, then use allowable); and
n	=	The number of heaters and boilers with Qualifying Controls from those listed in Appendix C that are selected by CITGO to satisfy the requirements of the equation set forth in this Paragraph 54.

CITGO shall have sole discretion to select the Qualifying Controls to be applied on any particular heater, boiler or compressor engine and shall choose which heaters, boilers or compressor engines to control. Permit limits established to implement this Paragraph may use a 365-day rolling average for heaters and boilers that use a CEMS or PEMS to monitor compliance. CITGO shall install Qualifying Controls on two additional heaters or boilers with a heat input capacity of 40 mmBtu/hr or more, one at the Paulsboro Refinery and the other at the Savannah Refinery.

55. **Baseline Heater and Boiler Information.** Appendix C to this Consent Decree provides the following information for each heater or boiler larger than 40 mmBtu/hr that operated during the baseline years listed in Appendix C at the Covered Refineries (excluding those at the Paulsboro and Savannah Refineries):

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

b. the actual emission rate for baseline years in pounds of NOx per mmBtu heat input (HHV) and tons per year;

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

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

55A. **Revised Baseline Heater and Boiler Information.** By no later than February 28, 2005, CITGO shall submit a revised Appendix C to EPA for review and comment. This revision shall either (i) reflect that at least 75% of CITGO's total estimated ton per year average NOx emissions (derived from 1999 and 2000 data for the Lemont Refinery and 2001 and 2002 data for the Corpus Christi and Lake Charles Refineries) were derived from stack tests, CEMs, or portable analyzer or such other measurement device as maybe approved by EPA, or (ii) include results of stack tests (Method 7E or an alternative method as approved by EPA) on NOx emissions for the five heaters and boilers designated for stack tests in Appendix C. Appendix C (revised) will then be used to calculate the emission reductions required under this Section, including Paragraphs 54 and 57. The required reductions as specified in the inequality shall be 50% of the updated average CITGO NOx emissions (derived from 1999 and 2000 data for the Lemont Refinery and 2001 and 2002 data for the Corpus Christi and Lake Charles Refineries) in tons per year in the revised Appendix C.

56. **NOx Control Plan**. CITGO shall submit a detailed NOx control plan ("Control Plan") to EPA for review and comment by no later than March 31, 2005, with annual updates (covering the prior calendar year) with the first report submitted pursuant to Section IX (Record-keeping and Reporting) following the passage of each calendar year until termination of the Consent Decree or until the reductions required by Paragraph 54 are achieved, whichever occurs first. The Control Plan and its updates shall describe the achieved and anticipated progress of the NOx emissions reductions program for heaters and boilers and shall contain the following information for each heater and boiler greater than 40 mmBtu/hr that CITGO plans to use to satisfy the requirements of Paragraphs 54, 57, 58, and, if applicable, 57A:

a. All of the information in Appendix C;

b. Identification of the type of Qualifying Controls installed or planned with date installed or planned (including identification of the heaters and boilers to be permanently shut down);

c. 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;

d. The results of emissions tests and annual average CEMS data (in ppmvd at 0% O_2, and lbs/mmBtu) conducted pursuant to Paragraph 59 and tons per year; and

e. The amount in tons per year applied or to be applied toward satisfying Paragraph 54.

Appendix C, the Control Plan, and the updates required by this Paragraph shall be for informational purposes only and shall not be used to develop permit requirements or other operating restrictions. CITGO may change any projections, plans, or information (including, but not limited to, which units CITGO plans to control) that is included in the Control Plan or updates at any time.

57. By September 30, 2008, CITGO 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 54. In the first semi-annual update to be submitted to the Applicable Federal and State Agencies after September 30, 2008, CITGO shall include a report showing how it satisfied the requirement of this Paragraph. Consistent with Paragraph 54, CITGO shall install the remainder of the required Qualifying Controls by no later than June 30, 2011.

57A. By no later than December 31, 2005, CITGO shall inform EPA and the Co-Plaintiffs whether it will install a cogeneration system at the Lake Charles Refinery. If CITGO so informs EPA and the Co-Plaintiffs and installs the cogeneration system, the emission reduction required by Paragraph 54 shall be raised by 525 tons per year, but the interim emission reduction required by Paragraph 57 shall be reduced to 1125 tons per year.

58. By no later than June 30, 2011, CITGO shall have installed Qualifying Controls on at least 30% of the total heat input capacity in mmBtu per hour (at HHV) of heaters and boilers with capacities greater than 40 mmBtu/hr at each of the following refineries: Corpus Christi East, Corpus Christi West, Lake Charles and Lemont. Any Qualifying Controls may be used to satisfy this requirement, regardless of when the Qualifying Controls were installed.

59. For heaters and boilers where Qualifying Controls are installed after the Date of Lodging and beginning no later than 180 days after installing Qualifying Controls on and commencing operation of a heater and boiler that will be used to satisfy the requirements of Paragraph 54, CITGO shall monitor the heaters or boilers as follows:

a. For heaters and boilers with a capacity greater than 150 mmBtu/hr (HHV), install or continue to operate a NOx CEMS;

b. For heaters and boilers with a capacity greater than 100 mmBtu/hr (HHV) but less than or equal to 150 mmBtu/hr (HHV), install or continue to operate a NOx CEMS, or monitor NOx emissions with a predictive emissions monitoring system ("PEMS") developed and operated pursuant to the requirements of the PEMS Program prepared by CITGO under this Paragraph.

c. For heaters and boilers with a capacity of less than or equal to 100 mmBtu/hr (HHV), conduct an initial performance test and any periodic tests that may be required by EPA or by the applicable State or local permitting authority under other applicable regulatory authority. The results of the initial performance testing shall be reported to EPA and Applicable Permitting Authority within 90 days of completing the stack test.

CITGO shall use Method 7E to conduct initial performance testing required by Subparagraph 59c. Monitoring with a PEMS that is required by this Paragraph shall be conducted in accordance with the requirements of Appendix H. By no later than September 30, 2005, CITGO shall submit to EPA for review and comment a PEMS Program in accordance with Appendix H. By no later than September 30, 2005, CITGO shall implement the specified monitoring requirements (CEMS, PEMS, stack test) based on the capacity of the heater or boiler as listed in Appendix C for units that utilize Qualifying Controls as of the Date of Lodging and which CITGO intends to use to achieve the NOx reductions required by Paragraph 54.

60. **<u>Demonstrating Compliance through Use of a NOx CEMS</u>.** CITGO shall install, certify, calibrate, maintain, and operate the CEMS required by Paragraph 59 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. However, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, CITGO 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.

61. The requirements of this Section V.F. do not exempt CITGO 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 Section V.F. is meant to prevent CITGO 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.

62. CITGO shall retain records demonstrating installation of Qualifying Controls under Paragraph 54 and monitoring/test data under Paragraph 59 until termination of the Consent Decree. CITGO shall submit such records to EPA upon request.

G. SO_2 EMISSIONS REDUCTIONS FROM AND NSPS APPLICABILITY OF HEATERS, BOILERS AND OTHER FUEL GAS COMBUSTION DEVICES

63. **General**. CITGO shall undertake measures to limit SO_2 emissions from refinery heaters and boilers and other fuel combustion devices by restricting H2S in refinery fuel gas and by agreeing not to burn Fuel Oil except as specifically permitted under the provisions of this Section V.G. Flaring Devices are not subject to the provisions of Section V.G., but rather are subject to the provisions of Sections V.I., V.J. and V.K.

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

a. Upon the Date of Entry, each heater and boiler that combusts refinery fuel gas at 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 E, 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 E.

b. By the date listed in Appendix F, each of the fuel gas combustion devices listed in Appendix F 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 E or F specifies an alternative monitoring plan ("AMP") submittal date (rather than a final NSPS Subpart J compliance date), CITGO shall submit to EPA a timely and complete AMP application by the date(s) specified. To the extent that CITGO 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" attached to EPA's December 7, 1999 letter to Koch Refining Company LP, which is attached hereto in Appendix I, CITGO may begin using such method immediately upon submitting its application for approval to use such method. If an AMP is not approved, CITGO shall submit to EPA for approval a plan for complying with the monitoring requirements of NSPS Subpart J for the particular equipment within ninety (90) days of receiving notice of the disapproval. The equipment will become an affected facility when the AMP has been approved or CITGO has fully implemented its approved plan. Such plan 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 H2S 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 H2S concentration is not likely to exceed 0.1 grains H2S 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.

65. **Elimination/Reduction of Fuel Oil Burning.** Effective on the Date of Entry, CITGO shall not burn Fuel Oil in any combustion unit at the Covered Refineries except during periods of Natural Gas Curtailment. Nothing herein is intended to limit, or shall be interpreted as limiting, the use of torch oil during FCCU Startups.

H. SULFUR RECOVERY PLANTS

66. **Description of Sulfur Recovery Plants.** CITGO owns and operates Claus Sulfur Recovery Plants ("SRPs") at the Lemont, Lake Charles, Corpus Christi East and Corpus Christi West Refineries.

a. Lemont SRP: The SRP at the Lemont Refinery ("Lemont SRP") consists of four Claus trains, Units 119 A, 119 B, 121 C and 121 D. There is a single Beavon Stretford Tail Gas Unit ("TGU") which serves as the control device for the two 121 Claus trains.

b. Lake Charles SRP: The SRP at the Lake Charles Refinery consists of four Claus trains, A, C, D and E. There are two amine solution TGUs that serve the above-listed Claus trains.

c. Corpus Christi (East) SRP: The SRP at the Corpus Christi (East) Refinery consists of two Claus trains. There is a single SCOT TGU which serves as the control device for the two Claus trains.

d. Corpus Christi (West) SRP: The SRP at the Corpus Christi (West) Refinery consists of two Claus trains. There is a single SCOT TGU which serves as the control device for the two Claus trains.

67. **Claus Sulfur Recovery Plant NSPS Applicability.** Each of the following Claus Sulfur Recovery Plants shall be an "affected facility," as that term is used in 40 C.F.R. Part 60, as follows:

a. Effective on the Date of Entry of the Consent Decree, each SRP at the Lake Charles, Corpus Christi East and Corpus Christi West Refineries shall be an "affected facility" under NSPS, 40 C.F.R. Part 60, Subparts A and J;

b. Effective no later than 90 days after installation of one or more TGU(s) to control the emissions from the Lemont Claus trains 119 A and B, as required under Paragraph 69, the SRP at the Lemont Refinery shall be an "affected facility" under NSPS, 40 C.F.R. Part 60, Subparts A and J;

c. Notwithstanding Paragraph 67.b, above, effective on the Date of Entry of the Consent Decree until such time as the SRP at the Lemont Refinery is an "affected facility," the Lemont Claus Trains 121 C and D ("Lemont Claus Trains") shall be treated under this Consent Decree as an SRP that is an "affected facility" that must comply with all provisions applicable to such an affected facility under 40 C.F.R. Part 60, Subparts A and J.

68. **Claus Sulfur Recovery Plant NSPS Compliance.** By no later than the effective date of NSPS applicability for each of the SRPs and the Lemont Claus Trains as set forth in Paragraph 67, above, the SRPs and the Lemont Claus Trains shall 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. CITGO shall, for all periods of operation of the SRPs, comply with 40 C.F.R. § 60.104(a)(2) at each SRP except during periods of Startup, Shutdown or Malfunction of the respective SRP, or during a Malfunction of a TGU serving as a control device for the SRP. For the purpose of determining compliance with the Sulfur Recovery Plant emission limits of 40 C.F.R. § 60.104(a)(2), the "Startup/Shutdown" provisions set forth in NSPS Subpart A shall apply to each SRP and not to the independent start-up or shutdown of a TGU serving as a control device for the SRP. However, the Malfunction exemption set forth in NSPS Subpart A shall apply to each SRP and to the TGU serving as the control device for the SRP.

b. Monitoring. CITGO 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 life of this Consent Decree, CITGO shall conduct emissions monitoring from these SRPs with CEMS at all of the emission points, unless an SO_2 alternative monitoring procedure has been approved by EPA, per 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.

69. **Lemont SRP Requirements.**

a. CITGO shall install one or more TGU(s) to control the emissions from the Lemont Claus Trains 119 A and B by no later than December 31, 2008. By no later than February 28, 2005, CITGO shall submit to EPA and IEPA a schedule for Lemont Claus trains 119 A and B that will ensure compliance with SRP NSPS requirements by no later than December 31, 2008.

b. CITGO shall also implement the following interim measures at the Lemont Claus Trains 119 A and B:

i. CITGO shall continue to operate and maintain an SO_2 CEMS for monitoring the emissions from Lemont Claus Trains 119 A and B in accordance with 40 C.F.R. Part 60, Subpart A, § 60.13.

ii. By no later than February 28, 2005, CITGO shall complete an optimization study to minimize emissions and maximize sulfur recover efficiencies at Lemont Claus Trains 119 A and B and shall submit a copy of that study to EPA and IEPA. This study shall meet the requirements set forth in Paragraph 70. CITGO shall promptly implement the physical improvements and operating parameters recommended in the study to optimize performance of Lemont Claus Trains119 A and B.

iii. By no later than April 30, 2005, CITGO shall submit a report to EPA and IEPA that proposes an appropriate interim performance standard (percent recovery efficiency and/or emission limitation) and, if necessary, a schedule for implementing related optimization study recommendations that are necessary to comply with CITGO's proposed standard. Beginning with the date of such submission, CITGO shall comply with its proposed interim performance standard or, if necessary, implement its proposed implementation schedule.

iv. 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, after an opportunity for consultation with IEPA, EPA shall so notify CITGO. Unless CITGO disputes EPA's determination(s) within 90 days of its receipt of that notice, it shall 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. CITGO shall continue to comply with the appropriate interim performance standard until such time as CITGO completes installation of the TGU(s) in accord with the schedule under Paragraph 69.a and operates the Lemont SRP in compliance with NSPS Subpart J.

70. **Optimization**. The optimization studies required for the Lemont Claus Trains 119 A and B shall meet the following requirements:

a. Detailed evaluation of plant design and capacity, operating parameters and efficiencies - including catalytic activity, and material balances;
b. 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, in those Claus trains;
c. A 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;

d. Establishment of baseline data through testing and measurement of key parameters throughout the Claus train;
e. Establishment of a thermodynamic process model of the Claus train;
f. For any key parameters that have been determined to be at less than optimal levels, initiation of changes designed to move such parameters toward their optimal values;
g. Verification through testing, analysis of continuous emission monitoring data or other means, of incremental and cumulative improvements in sulfur recovery efficiency, if any;
h. Establishment of new operating procedures for long-term efficient operation; and
i. Each study shall be conducted to optimize the performance of the Claus trains in light of the actual characteristics of the feeds to the trains.

71. **Sulfur Pit Emissions.** CITGO shall continue to route or re-route all sulfur pit emissions at the Lemont, Lake Charles, and Corpus Christi East and West Refineries so that they are eliminated, controlled, or included and monitored as part of the SRP's emissions subject to the NSPS Subpart J limit for SO_2, 40 C.F.R. § 60.104(a)(2), by no later than the earlier of: (i) the first turnaround of the applicable Claus train that occurs on or after October 31, 2004; or (ii) March 30, 2007, provided, however, that if Lemont Claus Trains 119A and/or 119B elect to route such emissions to the TGU required under Paragraph 69.a, then by the date of such TGU installation.

72. **Sulfuric Acid Plant.** By no later than December 31, 2006, the Lake Charles Sulfuric Acid Plant shall be an "affected facility," as that term is used in 40 C.F.R. Part 60, Subparts A and H, and shall comply with an emission limitation of 3.5 pounds of sulfur dioxide per ton of acid produced, three hour average, (production expressed as 100 percent sulfur acid); the acid mist standards found in 40 C.F.R. § 60.83; and the emissions monitoring and testing requirements in 40 C.F.R. Part 60, Subparts A and H. The Lake Charles Sulfuric Acid Plant

shall comply with the 3.5 lb SO_2 per ton limit and the acid mist standards at all times except during periods of Startup, Shutdown or Malfunction of the Sulfuric Acid Plant.

73. **Good Operation and Maintenance**.

a. By no later than February 28, 2005, CITGO shall submit to EPA and the appropriate Co-Plaintiff a summary of the plans, implemented or to be implemented, at the Lemont, Lake Charles, and Corpus Christi East and West Refineries for enhanced maintenance and operation of their SRPs, the Lake Charles Sulfuric Acid Plant and the appropriate Upstream Process Units. This plan shall be termed a Preventive Maintenance and Operation Plan ("PMO Plan"). The PMO Plan shall be a compilation of CITGO's approaches for exercising good air pollution control practices and for minimizing SO_2 emissions from sulfur processing and other production processes at these refineries. PMO Plans shall have as their goals the elimination of Acid Gas Flaring and operation of SRPs between Scheduled Maintenance turnarounds with minimization of emissions. The PMO Plan shall include, but not be limited to, sulfur shedding procedures, startup and shutdown procedures of SRP's, 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. CITGO shall implement the PMO Plans at all times, including periods of Startup, Shutdown and Malfunction of its SRPs. Changes to a PMO Plan related to minimizing Acid Gas Flaring and/or SO_2 emissions shall be summarized and reported by CITGO to EPA and the appropriate Co-Plaintiff in the semi-annual report required under Paragraph 144.

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

I. HYDROCARBON FLARING

74. **Good Air Pollution Control Practices**. On and after the Date of Entry, CITGO 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 Hydrocarbon Flaring Devices consistent with 40 C.F.R. § 60.11(d). CITGO shall implement such good air pollution control practices to minimize Hydrocarbon Flaring Incidents by investigating, reporting and correcting all Hydrocarbon Flaring Incidents in accordance with the procedures in Paragraph 94.

75. **NSPS Applicability of Hydrocarbon Flaring Devices**: CITGO owns and operates the NSPS Hydrocarbon Flaring Devices identified in Appendix B-1 to this Consent Decree. By no later than the dates identified in Appendix G, CITGO agrees that each such NSPS HC Flaring Device is an "affected facility" (as that term is used in NSPS, 40 C.F.R. Part 60) 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 used as emergency control devices for quick and safe release of gases.

a. CITGO shall meet the NSPS Subparts A and J requirements for each NSPS HC Flaring Device by using one or any combination of the following methods:

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

ii. Eliminating the routes of continuous or intermittent, routinely-generated refinery fuel gases to an NSPS HC Flaring Device and operating the Flaring Device such that it only receives non-routinely generated gases, process upset gases, fuel gas released as a result of relief valve leakage or gases released due to other emergency malfunctions; or

iii. Operating the NSPS HC Flaring Device as a fuel gas combustion device, monitoring it for the continuous or intermittent, routinely-generated refinery fuel gases streams put into the flare header, with a CEMS as required by 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) and complying with emission limits when and as required by Paragraph 76.a.

CITGO shall implement the compliance option chosen for each NSPS Hydrocarbon Flaring Device according to the schedule in Appendix G and identify the option that was implemented for each NSPS Hydrocarbon Flaring Device in the first Semi-Annual Report due under Paragraph 144 after such compliance is achieved. The Parties recognize that periodic maintenance may be required for properly designed and operated flare gas recovery systems. CITGO shall take all reasonable measures to minimize emissions while such periodic maintenance is being performed.

b. Within 90 days after bringing an NSPS Hydrocarbon Flaring Device into compliance with NSPS Subparts A and J, CITGO shall conduct a flare performance test pursuant to 40 C.F.R.§§ 60.8 and 60.18, or an EPA-approved equivalent method. In lieu of conducting the velocity test required in 40 C.F.R. §60.18, CITGO may submit velocity calculations which demonstrate that the NSPS Hydrocarbon Flaring Device meets the performance specification required by 40 C.F.R. §60.18.

76. **<u>Compliance with the Emission Limit at 40 C.F.R. § 60.104(a)(1)</u>.**

a. <u>Continuous or Intermittent, Routinely-Generated Refinery Fuel Gases</u>. For continuous or intermittent, routinely-generated refinery gases that are combusted in any of the NSPS Hydrocarbon Flaring Devices, CITGO shall comply with the emission limit at 40 C.F.R. § 60.104(a)(1) by the dates specified in Appendix G.

b. <u>Non-Routinely Generated Gases</u>. The combustion of gases generated by the Startup, Shutdown, or Malfunction of a refinery process unit or released to an NSPS Flaring Device as a result of relief valve leakage or other emergency Malfunction are exempt from the requirement to comply with 40 C.F.R. § 60.104(a)(1).

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

77. **<u>Flaring History and Corrective Measures</u>**. CITGO has conducted a look-back analysis of AG Flaring Incidents that occurred at the Covered Refineries from October 1, 1998, through September 30, 2003, and submitted a report on such incidents to EPA.

78. **<u>Future Acid Gas Flaring and Tail Gas Incidents:</u>**. CITGO shall investigate the cause of future Acid Gas Flaring and Tail Gas Incidents, take reasonable steps to correct the conditions that have caused or contributed to such Acid Gas Flaring and Tail Gas Incidents, and minimize Acid Gas Flaring and Tail Gas Incidents at the Corpus Christi East, Corpus Christi West, Lemont and Lake Charles Refineries.

79. **Investigation and Reporting.** No later than forty-five (45) days following the end of an Acid Gas Flaring Incident occurring after the Date of Entry, CITGO shall submit to EPA and the appropriate Co-Plaintiff a report that sets forth the following:

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

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

c. The steps, if any, that CITGO took to limit the duration and/or quantity of sulfur dioxide emissions associated with the Acid Gas Flaring Incident;

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

e. An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Acid Gas 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 CITGO concludes that corrective action(s) is (are) required under Paragraph 80, 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 CITGO concludes that corrective action is not required under Paragraph 80, the report shall explain the basis for that conclusion;

f. A statement that: (a) specifically identifies each of the grounds for stipulated penalties in Paragraphs 86 and 87 of this Decree and describes whether or not the Acid Gas Flaring Incident falls under any of those grounds, provided, however, that CITGO 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 CITGO's potential defenses; (b) if an Acid Gas Flaring Incident falls under Paragraph 88 of this Decree, describes which Subparagraph 88.a or 88.b applies and why; and (c) if an Acid Gas Flaring Incident falls under either Paragraph 87 or 88.b, states whether or not CITGO asserts a defense to the Flaring Incident, and if so, a description of the defense;

g. 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 79.d and 79.e shall be submitted; provided, however, that if CITGO 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 79 (or such additional time as EPA may allow) after the due date for the initial report for the Acid Gas Flaring Incident, the stipulated penalty provisions of Section XI shall apply, but CITGO 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 CITGO'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 CITGO from its investigation, reporting, and corrective action obligations under this Section for any Acid Gas Flaring Incident which occurs after an Acid Gas Flaring Incident for which CITGO has requested an extension of time under this Subparagraph 79.g; and

h. 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), CITGO shall submit a report identifying the corrective action(s) taken and the dates of commencement and completion of implementation.

80. **Corrective Action.**

a. In response to any AG Flaring Incident occurring after the Date of Entry, CITGO 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 CITGO in writing within forty-five (45) days of receipt of the report(s) required by Paragraph 79 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 Paragraph 80.a of this Decree. EPA does not, however, by its failure to object to any corrective action that CITGO 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 CITGO and explain the basis for its objection (s) in writing within forty-five (45) days following receipt of the report(s) required by Paragraph 79, and CITGO shall respond promptly to EPA's objection(s).

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

81. [Intentionally Left Blank]

82. [Intentionally Left Blank]

83. [Intentionally Left Blank]

84. [Intentionally Left Blank]

85. **Stipulated Penalties for Acid Gas Flaring Incidents.** The provisions of Paragraphs 86 through 89 are to be used by EPA in assessing stipulated penalties for AG Flaring Incidents

occurring after the Date of Entry of this Consent Decree and by the United States in demanding stipulated penalties under this Section V.J. The provisions of Paragraphs 86-89 do not apply to HC Flaring Incidents.

86. The stipulated penalty provisions of Paragraph 181 shall apply to any Acid Gas Flaring Incident for which the Root Cause was one or more or the following acts, omissions, or events:

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

b. Failure to follow written procedures;

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

87. If the Acid Gas Flaring Incident is not a result of one of the Root Causes identified in Paragraph 86, then the stipulated penalty provisions of Paragraph 181 shall apply if the Acid Gas Flaring Incident:

a. 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 CITGO failed to act in accordance with its PMO Plan and/or to take any action during the Acid Gas Flaring Incident to limit the duration and/or quantity of SO_2 emissions associated with such incident; or

b. Causes the total number of Acid Gas Flaring Incidents in a rolling twelve (12) month period to exceed five (5) per refinery.

88. With respect to any Acid Gas Flaring Incident not identified in Paragraphs 86 or 87, the following provisions shall apply:

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

(i) If the Root Cause of the Acid Gas 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 Acid Gas Flaring Incidents;

(ii) If the Root Cause of the Acid Gas Flaring Incident was sudden and infrequent, and was reasonably preventable through the exercise of good engineering practice, then CITGO shall implement corrective action(s) pursuant to Paragraph 80, and the stipulated penalty provisions of Section XI shall not apply.

b. Recurrence: If the Root Cause is a recurrence of the same Root Cause that resulted in a previous Acid Gas Flaring Incident that occurred since the Date of Entry, then CITGO shall be liable for stipulated penalties under Section XI unless:

(i) the Flaring Incident resulted from a Malfunction; or

(ii) the Root Cause previously was designated as an agreed-upon malfunction under Paragraph 88.a.i; or

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

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

a. Force majeure.

b. As to Paragraph 86, the Acid Gas Flaring Incident does not meet the identified criteria.

c. As to Paragraph 87, Malfunction

d. As to Paragraph 88, the Incident does not meet the identified criteria and/or was due to a Malfunction.

90. In the event a dispute under Paragraphs 85 through 89 is brought to the Court pursuant to the Dispute Resolution provisions of this Consent Decree, CITGO may also assert a

Start up, Shutdown and/or upset defense (including of an individual sulfur recovery unit within an SRP), but the United States shall be entitled to assert that such defenses are not available. If CITGO prevails in persuading the Court that the defenses of Startup, Shutdown and/or upset are available for AG Flaring Incidents under 40 C.F.R. 60.104(a)(1), CITGO shall not be liable for stipulated penalties for emissions resulting from such Startup, Shutdown and/or upset. If the United States prevails in persuading the Court that the defenses or Startup, Shutdown and/or upset are not available, CITGO shall be liable for such stipulated penalties.

91. Other than for a Malfunction or force majeure, if no Acid Gas Flaring Incident occurs at either the Corpus Christi East, Corpus Christi West, Lake Charles or Lemont Refinery for a rolling 36 month period, then the stipulated penalty provisions of Section V.J. shall no longer apply to that Refinery. EPA may elect to reinstate the stipulated penalty provision if such Refinery has an Acid Gas Flaring Incident which would otherwise be subject to stipulated penalties. EPA's decision shall not be subject to dispute resolution. Once reinstated, the stipulated penalty provision shall continue for the remaining life of this Consent Decree for that Refinery.

92. **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:

$$\text{Tons of } SO_2 = [FR][TD][ConcH_2S][8.44 \times 10^{-5}].$$

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 92:

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 tube analysis or by any other method approved by EPA or the Co-Plaintiffs. 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 79 shall include the data used in the calculation and an explanation of the basis for any estimates of missing data points.

93. **Tail Gas Incidents**.

a. Investigation, Reporting, Corrective Action and Stipulated Penalties. For Tail Gas Incidents, CITGO shall follow the same investigative, reporting, corrective action and assessment of stipulated penalty procedures as those set forth in Paragraphs 79 through 91 for Acid Gas 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 a Claus Sulfur Recovery Plant. Notwithstanding the foregoing, stipulated penalties shall not apply to a Tail Gas Incident attributable to the scheduled startup or shutdown of an individual train at the SRP located at the Lake Charles Refinery, provided that CITGO demonstrates that it has implemented good air pollution control practices. This Paragraph 93 shall apply after the effective date of NSPS applicability at each of the Covered Refineries' SRPs, as provided in Paragraph 67 above.

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 92; or

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

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

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 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 CITGO shall estimate emissions based on best engineering judgment.

K. CONTROL OF HYDROCARBON FLARING INCIDENTS

94. For Hydrocarbon Flaring Incidents occurring after the Date of Entry, CITGO shall follow the same investigative, reporting, and corrective action procedures as those set forth in Section V.J. for Acid Gas Flaring Incidents; provided however, that in lieu of analyzing possible corrective actions under Paragraph 79.e and taking interim and/or long-term corrective action under Paragraph 80 for a Hydrocarbon Flaring Incident attributable to the startup or shutdown of a unit that CITGO has previously analyzed under this Paragraph, CITGO may identify such prior analysis when submitting the report required under this Paragraph. By no later than the dates specified in Appendix G for identified coker flares, CITGO will install equipment to minimize HC Flaring from coker blowdown cycles. Prior to the completion of these projects, CITGO shall not be required to identify or implement corrective action(s), as under Paragraph 80, for HC Flaring Incidents from coker blowdown cycles, unless more than 500 lbs. of SO_2 would have been released if such equipment had been installed and in use. CITGO shall submit the Hydrocarbon Flaring Incident(s) reports as part of the Semi-annual Progress Reports required pursuant to Section IX. Stipulated penalties under Paragraphs 85 - 91 and Section XI shall not apply to Hydrocarbon Flaring Incident(s). The formulas at Paragraph 92, used for calculating the quantity and rate of sulfur dioxide emissions during AG Flaring Incidents, shall be used to calculate the quantity and rate of sulfur dioxide emissions during HC Flaring Incidents. Neither this Paragraph 94 nor Section V.J. of this Consent Decree shall apply to Hydrocarbon Flaring Device 343 B-5 Flare Central at the Lake Charles Refinery.

L. BENZENE WASTE NESHAP PROGRAM ENHANCEMENTS

95. In addition to continuing to comply with all applicable requirements of 40 C.F.R. Part 61, Subpart FF ("Benzene Waste NESHAP" or "Subpart FF"), CITGO agrees to undertake

the measures set forth in Section V.L. to ensure continuing compliance with Subpart FF and to minimize or eliminate fugitive benzene waste emissions at each Covered Refinery.

96. **Current Subpart FF Status.**

a. CITGO has determined that the Lake Charles, Lemont, and Corpus Christi East Refineries each has a total annual benzene (TAB) of greater than 10 megagrams (Mg) per year. Commencing on the Date of Entry of the Consent Decree, each of the above referenced refineries shall comply with the compliance option set forth at 40 C.F.R. § 61.342(e) (herein referred to as the "6BQ Compliance Option"); and

b. CITGO has determined that the Corpus Christi West, Paulsboro and Savannah Refineries each has a TAB of less than 10 Mg/yr and that the Corpus Christi West Refinery has a TAB of greater than 1.0 Mg/yr.

97. **Refinery Compliance Status Changes.** Commencing on the Date of Entry of the Consent Decree and for the duration of the Consent Decree, CITGO shall not change the compliance option of the Lake Charles, Lemont, or Corpus Christi East Refineries from the 6BQ Compliance Option to the compliance options set forth at 40 C.F.R. § 61.342(c) or (d). If at any time from the Date of Entry of the Consent Decree through its termination, the Paulsboro, Savannah or Corpus Christi West Refineries are determined to have a TAB equal to or greater than 10 Mg/yr, each such refinery shall comply with the 6 BQ Compliance Option.

98. **One-Time Review and Verification of Each Refinery's TAB and Compliance with the Benzene Waste NESHAP, including the 6 BQ Compliance Option**.

a. Phase One of the Review and Verification Process. By no later than April 30, 2005, CITGO shall complete a review and verification of the Lake Charles, Lemont, Corpus Christi East, Corpus Christi West, and Savannah Refineries TAB and its compliance with the Benzene Waste NESHAP, including the 6 BQ Compliance Option (if applicable). CITGO shall complete a review and verification of the Paulsboro Refinery TAB and compliance with the Benzene Waste NESHAP by no later than August 31, 2005. CITGO's review and verification process at each Covered Refinery 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 where these waste streams meet the definition of a waste under 40 C.F.R. § 61.341 (e.g., slop oil, tank water draws, spent caustic, spent caustic hydrocarbon layer, 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 Refinery for the Lake Charles, Lemont, Corpus Christi East and Corpus Christi West Refineries, and no less than 5 waste streams per Refinery for the Paulsboro and Savannah Refineries, 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;

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 thirty (30) days following the completion of Phase One of the review and verification process, CITGO shall submit a Benzene Waste NESHAP Compliance Review and Verification report ("BON Compliance Review and Verification Report") that sets forth the results of Phase One, including but not limited to the items identified in Subparagraphs (i) through (v) of this Paragraph.

b. Phase Two of the Review and Verification Process. Based on EPA's review of the BON Compliance Review and Verification Report(s), EPA may select up to 20 additional waste streams at each Covered Refinery for sampling for benzene concentration. CITGO shall conduct the required sampling under representative conditions and submit the results to EPA within sixty (60) days of receipt of EPA's request. CITGO shall use the results of this additional sampling to recalculate the TAB and the uncontrolled benzene quantity, except where such results are not accurate due to identified laboratory or analytical error, and to amend the BON Compliance Review and Verification Report, as needed. To the extent that EPA requires CITGO to re-sample any waste stream sampled by CITGO on or after January 1, 2003, CITGO may average the results of such sampling events. CITGO shall submit an amended BON Compliance Review and Verification Report within ninety (90) days following the date of the completion of the required Phase Two sampling, if Phase Two sampling is required by EPA.

99. [Intentionally Left Blank]

100. **Implementation of Actions Necessary to Correct Non-Compliance or to Come Into Compliance.**

a. Amended TAB Reports. If the results of the BON Compliance Review and Verification Report(s) indicate(s) that the reports submitted by CITGO pursuant to 40 C.F.R. § 61.357(c) or 61.357(d) for the Covered Refineries have not been filed or are inaccurate and/or do not satisfy the requirements of Subpart FF, CITGO shall submit, by no later than sixty (60) days after completion of the BON Compliance Review and Verification Report(s), an amended TAB report to the Applicable Federal and State Agencies.

b. Submittal of Compliance Plans for the Paulsboro, Savannah, and Corpus Christi West Refineries. If the results of the BON Compliance Review and Verification Report indicate that the TABs at the Paulsboro, Savannah, or Corpus Christi West Refineries exceed 10 Mg/yr, CITGO shall submit to EPA and the appropriate Co-Plaintiff, by no later than 180 days after completion of the BON Compliance Review and Verification Report, a plan that identifies with specificity the compliance strategy and schedule that CITGO will implement to ensure that the subject Refinery complies with the 6 BQ Compliance Option as soon as practicable. If the results of the BON Compliance Review and Verification Report indicate that the TAB at the Paulsboro, Savannah, or Corpus Christi West Refineries is: (i) below 1 Mg/yr; or (ii) less than 10 Mg/yr but equal to or greater than 1 Mg/yr, CITGO shall comply with the applicable Benzene Waste NESHAP regulations for such categories of refineries.

c. Submittal of Compliance Plans for the Lake Charles, Lemont, and Corpus Christi East Refineries. If the results of the BON Compliance Review and Verification Report indicate that the uncontrolled benzene quantity at the Lake Charles, Lemont, or Corpus Christi East Refineries exceeds 6 Mg/yr, CITGO shall submit to the Applicable Federal and State Agencies, by no later than 180 days after completion of the BON Compliance Review and Verification Report, a plan that identifies with specificity the compliance strategy and schedule that CITGO will implement to ensure that the subject Refinery complies with the 6 BQ Compliance Option as soon as practicable.

d. Review and Approval of Plans Submitted Pursuant to Paragraphs 100.b and 100.c. Any plan submitted pursuant to Paragraphs 100.b or 100.c shall be subject to approval or disapproval by EPA, which shall act after an opportunity for consultation with the appropriate Co-Plaintiff. Within sixty (60) days after receiving any notification of disapproval from EPA, CITGO shall submit to EPA and the appropriate Co-Plaintiff a revised plan that responds to all identified or alleged deficiencies. Upon receipt of approval or approval with conditions, CITGO shall implement the plan according to the schedule provided in the approved plan.

e. Certification of Compliance with the 6 BQ Compliance Option. By no later than thirty (30) days after completion of the implementation of all actions, if any, required pursuant to Paragraphs 100.b, 100.c, or 100.d to come into compliance with the 6 BQ Compliance Option, CITGO shall submit a report to EPA and the appropriate Co-Plaintiff certifying that, as to the subject Refinery, the Refinery complies with the Benzene Waste NESHAP.

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

a. CITGO shall continue to use primary and secondary carbon canisters and operate them in series at all Covered Refineries where such systems are in use as of the Date of Entry of the Consent Decree and shall maintain a complete, accurate and up-to-date list at each such Covered Refinery that identifies the location where each secondary carbon canister is installed and whether VOC or benzene is used to monitor for breakthrough at each such canister under Paragraph 101.d, including the date of any change to the constituent being monitored for breakthrough.

b. Except as expressly permitted under Paragraph 101.f, CITGO shall not use single carbon canisters for any new units or installations that require controls pursuant to the Benzene Waste NESHAP at any of its Covered Refineries.

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 volatile organic compounds, excluding ethane and methane (hereinafter in Section V.L. only "VOC"), or 5 ppm benzene.

d. CITGO 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 Date of Entry where dual carbon canisters currently are in service; and (ii) within seven days after installation of a new, dual carbon canister system.

e. CITGO shall replace the original primary carbon canisters immediately when breakthrough is detected between the primary and secondary canister. The original secondary carbon canister will become the new primary carbon canister and a fresh carbon canister will become the secondary canister. For purposes of this Paragraph, "immediately" shall mean within twelve (12) 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, CITGO may elect to monitor the outlet of the secondary canister the day 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, the primary canister must be replaced within twelve (12) hours of the detection of a breakthrough. The original secondary carbon canister will become the new primary carbon canister and a fresh carbon canister will become the secondary canister.

f. <u>Temporary Applications</u>. CITGO 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 Decree as any reading of VOC above background or benzene above 1 ppm. Beginning no later than October 31, 2004, CITGO shall monitor for breakthrough from single carbon canisters each day such canister is used. CITGO 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 this Paragraph, "immediately" shall mean within twelve (12) 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. If CITGO discontinues flow to the single carbon canister or routes the stream to an alternate, appropriate control device, such canister must be replaced before it is returned to service.

g. CITGO shall maintain a readily available supply of fresh carbon canisters at each Covered Refinery at all times or otherwise ensure that such canisters are readily available to implement the requirements of this Paragraph 101.

h. CITGO 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.

102. **<u>Annual Program.</u>** By no later than May 31, 2005, CITGO shall establish or modify its 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 Covered Refinery's waste stream inventory. CITGO shall conduct such reviews on an annual basis.

103. **Laboratory Audits**. CITGO shall conduct audits of all laboratories that perform analyses of CITGO'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 September 30, 2005, CITGO shall complete initial audits of each laboratory used by it. In addition, CITGO shall conduct a similar audit of any laboratory to be used for analyses of benzene samples prior to such use. If CITGO has completed an audit of any laboratory on or after June 30, 2003, initial audits of those laboratories pursuant to this subparagraph shall not be required.

b. If and to the extent that a Covered Refinery submits its Benzene Waste NESHAP samples to laboratories audited and certified by New Jersey for the testing method required by the Benzene Waste NESHAP (as required for the Paulsboro Refinery under New Jersey law), CITGO need not separately audit such laboratory(ies) under this Paragraph.

c. During the life of this Consent Decree, CITGO shall conduct subsequent laboratory audits, such that each laboratory is audited every two (2) years.

d. CITGO 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 CITGO's.

104. **Benzene Spills**. For each spill at each Covered Refinery after the Date of Entry of this Consent Decree, CITGO 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, CITGO shall: (i) include the benzene waste generated by the spill in the relevant 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.

105. **Training.**

a. By no later than May 31, 2005, CITGO shall develop and begin implementation of annual (i.e., once each calendar year) training for all employees who draw benzene waste samples for Benzene Waste NESHAP purposes.

b. For the Lake Charles, Corpus Christi East, and Lemont Refineries, by no later than September 30, 2005, CITGO shall complete the development of standard operating procedures for all control devices and treatment processes used to comply with the Benzene Waste NESHAP. By no later than December 31, 2005, CITGO shall complete an initial training program regarding these procedures for all operators assigned to applicable control devices and treatment processes. 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.

c. If and when the Paulsboro, Savannah, or Corpus Christi West Refineries' TAB reaches 10 Mg/yr or more, CITGO shall complete the development of standard operating procedures for all control devices and treatment processes used to comply with the Benzene Waste NESHAP. CITGO shall complete an initial training program regarding these procedures for all operators assigned to the relevant equipment. Training shall be provided to any persons who subsequently become operators, prior to their assumption of this duty. "Refresher" training shall be performed on a periodic basis. CITGO shall propose a schedule for the initial and refresher training at the same time that CITGO proposes a plan pursuant to Paragraph 100.b that identifies the compliance strategy and schedule that CITGO will implement to come into compliance with the 6 BQ Compliance Option.

d. CITGO shall assure that the employees of any contractors hired to perform any of the requirements of Section V.L of this Consent Decree are properly trained to implement such requirements that they are hired to perform, as under Paragraph 105.a-c.

106. **Waste/Slop/Off-Spec Oil Management**. By no later than February 28, 2005, for each Covered Refinery, CITGO shall submit to EPA and the appropriate Co-Plaintiff schematics that: (a) depict the waste management units (including sewers) that handle, store, and transfer waste/slop/off-spec oil streams; (b) identify the control status of each waste management unit; and (c) show how such oil is transferred within each Refinery. Representatives from CITGO and EPA thereafter may confer about the appropriate characterization of each Covered Refinery's waste/slop/off-spec oil streams and the necessary controls, if any, for the waste management units handling such oil streams for purposes of each Covered Refinery's TAB calculation and/or compliance with the 6 BQ Compliance Option. If requested by EPA, CITGO shall promptly submit revised schematics that reflect the Parties' agreements regarding the characterization of these oil streams and the appropriate control standards. CITGO shall use these schematics in preparing the end-of-line sampling plans required under Paragraph 107.

107. **Quarterly Sampling at End of Line and Point of Waste Generation for Refineries under the 6 BQ Compliance Option**. CITGO shall conduct quarterly sampling at the Lake Charles, Lemont, and Corpus Christi East Refineries under the terms of this Paragraph for the purpose of calculating quarterly, uncontrolled benzene quantities.

a. By no later than September 30, 2005, CITGO shall submit to EPA for approval a sampling plan designed to identify the quarterly benzene quantity in uncontrolled benzene waste streams, including waste/slop/off-spec oil. The sampling plan ("EOL 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 sampling, at the "point of waste generation," of each waste stream that contributes 0.05 Mg/yr or more to a Refinery's BQ; and (iv) quarterly sampling at all "end of line" and point of waste generation locations identified in Paragraph 107.a (i) and (iii).

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

c. CITGO shall commence sampling under its EOL Plan during the fourth calendar quarter of 2005 (regardless of whether or not the Plan is approved at that time). CITGO shall take, and have analyzed, at least three representative samples from each identified sampling location. CITGO 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 each Refinery.

108. **Quarterly Sampling at End of Line and Point of Waste Generation for the Paulsboro, Savannah, and Corpus Christi West Refineries**.

a. TAB is under 1 Mg/yr. If the results of the BON Compliance and Review Report indicate that the TAB for the Paulsboro or Savannah Refineries is less than 1 Mg/yr, no quarterly sampling shall be required.

b. TAB is less than 10 Mg/yr but equal to or greater than 1 Mg/yr. If the results of the BON Compliance and Review Report indicate that the TAB for the Paulsboro, Savannah, or Corpus Christi West Refineries is less than 10 Mg/yr but equal to or greater than 1 Mg/yr, CITGO shall comply with the provisions of Paragraph 107 except that: (i) the EOL Plan shall be due by no later than December 31, 2005; (ii) the quarterly sampling shall commence during the first month of the first full calendar quarter of 2006 (regardless of whether or not the Plan is approved at the time); and (iii) after eight (8) quarters of quarterly sampling, and based upon an evaluation of the prior sampling results, CITGO may submit a request to EPA to modify the frequency of the sampling. EPA, after an opportunity for consultation with the appropriate Co-Plaintiff, shall not unreasonably withhold its consent to such modification.

c. TAB is 10 Mg/yr or greater. If the results of the BON Compliance and Review Report indicate that the TAB for the Paulsboro, Savannah, or Corpus Christi West Refineries is 10 Mg/yr or greater, CITGO shall comply with the provisions of Paragraph 107 except that: (i) the EOL Plan shall be due by no later than ninety (90) days after the date of the submission of the final BON Compliance and Review Report; and (ii) the quarterly sampling shall commence during the first month of the first full calendar quarter immediately following CITGO's submission of the EOL Plan to EPA (regardless of whether or not the Plan is approved at the time).

109. **Calculation of Quarterly and Projected Calendar Year Uncontrolled Benzene Quantities and TABs**. For any Covered Refinery that is or becomes subject to the 6 BQ Compliance Option at any time during the duration of this Consent Decree, at the end of each Calendar Quarter following commencement of quarterly sampling, CITGO shall calculate a quarterly uncontrolled benzene quantity and shall estimate a projected calendar year uncontrolled benzene quantity based on the quarterly EOL sampling results, non-EOL sampling results, and the approved flow calculations. If, at any time during the duration of this Consent Decree, the TAB at the Paulsboro, Savannah, or Corpus Christi West Refineries is less than 10 Mg/yr but equal to or greater than 1 Mg/yr, CITGO shall calculate, at the end of each Calendar Quarter following commencement of quarterly sampling, a quarterly TAB and a projected calendar year TAB based on the quarterly EOL sampling results, non-EOL sampling results, and the approved flow calculations. CITGO shall submit the uncontrolled benzene quantity and, if applicable, TAB calculations in the progress reports due under Section IX of this Decree.

110. **Corrective Measures**.

a. Applicability. If, at any Covered Refinery that is or becomes subject to the 6 BQ Compliance Option at any time during the duration of this Consent Decree, the calculations in Paragraph 109 indicate that the quarterly uncontrolled benzene quantity exceeds 1.5 Megagrams or the projected calendar year uncontrolled benzene quantity exceeds 6.0 Megagrams, CITGO shall submit a written report to EPA and the appropriate 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, CITGO will include in its written report a plan as specified in Paragraph 110.b. If, at any time during the duration of this Consent Decree, the TAB at the Paulsboro or Savannah Refineries is equal to or greater than 1 Mg/yr, and the calculations in Paragraph 109 indicated that the quarterly TAB exceeds 2.5 Megagrams or the projected calendar year TAB exceeds 10.0 Megagrams, CITGO shall submit a written report to EPA and the appropriate 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 that its TAB remains below 10 Mg/yr, CITGO will include in its written report a plan as specified in Paragraph 110.b.

b. Corrective Measures Plan. CITGO shall, in any such corrective measures plan required by this Paragraph, identify: (i) the cause of the potentially elevated benzene quantities; (ii) all corrective actions that CITGO has taken or plans to take to ensure that the cause will not recur; and (iii) a specific strategy and schedule that CITGO shall implement to ensure that CITGO complies with the 6 BQ Compliance Option or generates less than 10 Mg/yr, as applicable. CITGO shall submit such plan and schedule, along with its report under Paragraph 110.a, by no later than 60 days after the end of the Calendar Quarter in which one or more of the conditions specified in the Paragraph 110.a is satisfied. CITGO shall implement its 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 Paragraph 110.a continues to exist and CITGO is not then able to identify the cause(s) and/or appropriate corrective measures to ensure compliance with the 6 BQ option or that the refinery's TAB remains below 10 Mg/yr, CITGO shall retain a third-party contractor to undertake a comprehensive TAB study and compliance review ("Third-Party TAB Study and Compliance Review") at the subject Refinery. By no later than the last day of the next following quarter, CITGO 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, CITGO shall authorize the contractor to commence work. CITGO shall ensure that the work is completed in accordance with the schedule provided therein. No later than thirty (30) days after CITGO receives the results of the Third-Party TAB Study and Compliance Review, CITGO shall submit the results to EPA. After the report is submitted to EPA, CITGO and EPA shall discuss informally the results of the Third-Party TAB Study and Compliance Review. No later than ninety (90) days after CITGO receives the results of the Third-Party TAB Study and Compliance Review or at such other time as CITGO and EPA may agree, CITGO 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, CITGO shall implement the remedial plan in accordance with the schedule included in its plan.

111. **Miscellaneous Measures.** The provisions of this Paragraph shall apply: (i) to the Lake Charles, Lemont, and Corpus Christi East Refineries, as of the Date of Entry of this

Consent Decree; and (ii) to the Paulsboro, Savannah, and Corpus Christi West Refineries only if the TAB reaches or exceeds 10 Mg/yr. CITGO shall:

a. Conduct monthly visual inspections of and, if appropriate, refill all Subpart FF water traps within each Refinery's individual drain systems;

b. Identify and mark at the drain all area drains that are segregated stormwater drains by no later than February 28, 2005;

c. If CITGO 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, CITGO 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. Nothing in this subparagraph shall require CITGO to monitor conservation vents on fixed roof tanks; and

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

112. **Recordkeeping and Reporting Requirements** CITGO shall submit to EPA, as and to the extent required, the following materials in the progress report(s) pursuant to Section IX (Reporting and Recordkeeping) for the six month period covered by the report:

a. 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;

b. A description of the measures taken, if any, during the six month period to comply with the training provisions of Paragraph 105; and

c. A summary of the sampling results required under Paragraphs 107 and 108, including the quarterly and projected annual uncontrolled benzene quantities or TABs, as applicable.

M. LEAK DETECTION AND REPAIR ("LDAR") PROGRAM ENHANCEMENTS.

113. 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, CITGO shall undertake the enhancements identified in this Section V.M. to its LDAR programs for each Covered Refinery 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. CITGO is not required to include in the enhanced program described herein any equipment or units not otherwise subject to the applicable federal, state or local LDAR regulation, nor is any requirement of this Section V.M. intended to change the criteria for identifying valves or pumps that are subject to the various LDAR programs.

114. [Intentionally Left Blank]

115. **Written Refinery-Wide LDAR Program**. By no later than April 30, 2005, CITGO shall develop and maintain a written program for compliance with all applicable federal and state LDAR regulations at each Covered Refinery. CITGO shall update the program as may be necessary to ensure continuing compliance. Such program shall include, at a minimum:

a. A leak rate goal for each Covered Refinery and a target for achievement on a process-unit-by-process-unit basis;

b. A procedure to identify all equipment in light liquid and/or in gas/vapor service that has the potential to leak VOCs, HAPs, VHAPs, and benzene within each Covered Refinery's process units;

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

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

e. Procedures for identifying and including in the LDAR program new equipment;

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

g. A definition or designation of "LDAR Personnel" responsible for the day-to-day implementation of the LDAR program and the designation of an "LDAR Coordinator" who has the authority and responsibility for implementing the enhanced LDAR program at each Covered Refinery (by name or position); and

h. A procedure for regularly communicating LDAR information to appropriate CITGO personnel.

116. **Training.** By no later than May 31, 2005, CITGO shall begin to implement the following training programs at each Covered Refinery:

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

b. For all personnel assigned LDAR responsibilities, CITGO shall provide and require completion of annual LDAR training. Initial annual LDAR training for all such personnel will be completed no later than September 30, 2005.

c. For all other operations and maintenance personnel (including contract personnel) at each Covered Refinery, CITGO 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 no later than September 30, 2005. "Refresher" training shall be performed annually; and

d. If contract employees are performing LDAR work, CITGO shall assure that its contractor complies with the training requirements in Subparagraphs 116.a-c, as appropriate, for all such contractor employees and shall require the contractor to provide its training information and records to CITGO.

117. **LDAR Audits**. CITGO shall implement at each Covered Refinery the refinery-wide audits set forth in this Paragraph to ensure each Covered Refinery's compliance with all applicable LDAR requirements. The LDAR audits shall include, but not be limited to, comparative monitoring, records review to ensure monitoring and repairs were completed in the required periods, component identification procedures, tagging procedures, data management procedures and observation of the LDAR technicians' calibration and monitoring techniques. During the LDAR audits, leak rates shall be calculated for each process unit where comparative monitoring was performed.

a. Initial Compliance Audit. By no later than September 30, 2005, CITGO shall complete a refinery-wide audit of its compliance with the LDAR regulations at each Covered Refinery, provided, however, that if CITGO elects to conduct a third-party audit at the Paulsboro and/or Savannah refineries under Paragraph 117.b, such audit must then be completed by no later than March 31, 2006. Each audit shall include, at a minimum, the audit requirements set forth in this Paragraph. Within 60 days of completion of each audit, CITGO shall either certify compliance with all LDAR requirements or submit a report to EPA and the appropriate Co-Plaintiff on areas of non-compliance identified as a result of its refinery-wide audit, including a proposed compliance schedule for correcting such non-compliance.

b. Third-Party Audits. CITGO shall retain a contractor(s) with expertise in the LDAR program requirements to perform a third-party audit of each Covered Refinery's LDAR program. The first third-party audit at Corpus Christi East, Corpus Christi West, Lake Charles and Lemont shall be completed pursuant to Subparagraph 117.a of this Paragraph (Initial Compliance Audit). Subsequent third-party audits shall be held every four (4) years thereafter for the life of this Consent Decree. CITGO is required by this Consent Decree to perform only one third-party audit at the Paulsboro and Savannah Refineries during the term of this Consent Decree.

c. Internal Audits. CITGO shall conduct internal audits of each Covered Refinery's LDAR Program by sending personnel familiar with the LDAR program and its requirements from one or more of CITGO's other Refineries or locations to audit another CITGO Refinery. CITGO shall complete the first round of these internal LDAR audits no later than two (2) years after the date of the completion of the Initial Compliance Audit required in Subparagraph 117.a. Internal audits of the Lake Charles, Lemont, Corpus Christi East, and Corpus Christi West Refineries shall be held every four years thereafter. Internal audits of the Paulsboro and Savannah Refineries shall be held every two (2) years thereafter.

d. Audit Frequency. To ensure that an audit at each Covered Refinery occurs at least every two years, third-party and internal audits shall be separated by no more than two years.

e. Alternative. As an alternative to the internal audits required by Subparagraph 117.c, CITGO may elect to retain third-parties to undertake these audits, provided that an audit of each Covered Refinery occurs every two (2) years.

118. **Implementation of Actions Necessary to Correct Non-Compliance**. If the results of any of the audits conducted pursuant to Paragraph 117 identify any areas of

noncompliance, CITGO shall implement, as soon as practicable, all steps necessary to correct or otherwise address such area(s) of non-compliance and to prevent a recurrence of the cause of that non-compliance, to the extent practicable. For the life of the Consent Decree, CITGO shall retain the audit reports generated pursuant to Paragraph 117 and shall maintain a written record of all corrective actions that CITGO takes in response to deficiencies identified in any audits. In the first semi-annual report after the completion of an audit, see Section IX of this Consent Decree (Recordkeeping and Reporting), CITGO shall submit a summary, including findings, of each such audit report and a list of corrective actions taken during the reporting period. In each subsequent semi-annual report under Section IX of this Consent Decree, CITGO shall submit a list of corrective actions taken during that reporting period and a notice, where appropriate, that all corrective actions have been completed in response to a particular audit at a Covered Refinery.

119. **Internal Leak Definition for Valves and Pumps**. CITGO 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 February 28, 2006, CITGO shall utilize an internal leak definition of 500 ppm VOCs for valves at the Lake Charles, Lemont, Corpus Christi East, Corpus Christi West, and Paulsboro Refineries, excluding pressure relief devices. By no later than December 31, 2006, CITGO shall utilize an internal leak definition of 500 ppm VOCs for valves at the Savannah Refinery, excluding pressure relief devices.

b. Leak Definition for Pumps. By no later than February 28, 2006, CITGO shall utilize an internal leak definition of 2000 ppm for each Covered Refinery's pumps.

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

a. Reporting. For regulatory reporting purposes, CITGO 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 119.

b. Recording, Tracking, Repairing and Remonitoring Leaks. CITGO shall begin recording, tracking, repairing and re-monitoring all leaks in excess of the internal leak definitions of Paragraph 119 at such time as those definitions become applicable. CITGO shall make a first attempt to repair and re-monitor leaks within five (5) days of identification. Within thirty (30) days of identification, CITGO shall either complete repairs and re-monitoring of leaks or place such component on the Covered Refinery's delay of repair list pursuant to Paragraph 128.

121. **LDAR Monitoring Frequency.**

a. Pumps. Unless more frequent monitoring is required by applicable federal, state and/or local requirements, CITGO shall monitor all pumps at all Covered Refineries at the internal leak definition on a monthly basis.

b. Valves. Unless more frequent monitoring is required by applicable federal, state and/or local requirements, CITGO shall monitor all valves at all Covered Refineries, other than difficult-to-monitor or unsafe-to-monitor valves, at the internal leak definition on a quarterly basis.

121A. **Monitoring After Turnaround or Maintenance**. CITGO shall have the option of monitoring affected valves and pumps within process unit(s) after completing a documented maintenance, startup, or shutdown activity without having the results of the monitoring count as a scheduled monitoring activity, provided that CITGO 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.

122. **<u>Initial Attempt at Repair of Valves</u>**. Beginning no later than September 30, 2005, at the Lake Charles, Lemont, Corpus Christi East, Corpus Christi West and Paulsboro Refineries and beginning no later than December 31, 2006, at the Savannah Refinery, CITGO shall make an "initial attempt" to repair any valve at any Covered Refinery that has a reading greater than 200 ppm of VOCs, excluding pressure relief devices, control valves and components that LDAR personnel are not authorized to repair. CITGO or its designated contractor shall make this "initial attempt" at repair and remonitor the leak within five (5) days of identification. 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, CITGO shall repair the valve according to the requirements of Paragraph 128, except that no first repair attempt requirement shall apply. If CITGO can demonstrate with 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 overall mass refinery emissions or emission rates from emitting

components in a reasonable, cost-effective manner, CITGO may request EPA to amend this requirement.

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

a. Electronic Storing and Reporting of LDAR Data. Beginning on the Date of Entry of the Consent Decree, CITGO shall continue to maintain an electronic database for storing and reporting LDAR data at all Covered Refineries.

b. Electronic Data Collection During LDAR Monitoring and Transfer Thereafter. By no later than December 31, 2004, CITGO shall use data loggers and/or electronic data collection devices during all LDAR monitoring at the Lake Charles, Lemont, Corpus Christi East, Corpus Christi West and Paulsboro Refineries. CITGO, or its designated contractor, shall use its best efforts to transfer on a daily basis the electronic data from electronic data logging devices to the electronic database maintained pursuant to Paragraph 123.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. CITGO may use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when data loggers are not available or broken), and at all times at the Savannah Refinery. If paper logs are used, CITGO 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. CITGO shall transfer any manually recorded monitoring data to the electronic database maintained pursuant to Paragraph 123.a within seven (7) days of the monitoring event.

124. **QA/QC of LDAR Data**. By no later than the Date of Entry of the Consent Decree, CITGO (or a third-party contractor retained by CITGO) shall have developed and begun

implementing procedures for quality assurance/quality control ("QA/QC") reviews of all data generated by LDAR monitoring technicians such that: (a) monitoring data is reviewed for QA/QC by the monitoring technicians daily after collection; and (b) all monitoring data is subject to a QA/QC review at least once per quarter, including but not limited to the number of components monitored per technician, time between monitoring events, and abnormal data patterns.

125. [Intentionally Left Blank]

126. [Intentionally Left Blank]

127. **Calibration/Calibration Drift Assessment.**

a. Calibration. CITGO shall conduct all calibrations of LDAR monitoring equipment at all Covered Refineries in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21.

b. Calibration Drift Assessment. Beginning no later than the Date of Entry of this Decree, CITGO shall conduct calibration drift assessments of LDAR monitoring equipment at each Covered Refinery at the end of each monitoring shift, at a minimum. CITGO shall conduct the calibration drift assessment using, at a minimum, a 500 ppm calibration gas. If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous calibration, CITGO shall re-monitor all valves that were monitored using that instrument and that had a reading greater than 100 ppm since its last calibration and shall re-monitor all pumps that were monitored using that instrument and that had a reading greater than 500 ppm since its last calibration.

c. CITGO shall maintain records of all instrument calibrations for a period of 1 year following the date of calibration.

128. **Delay of Repair**. Beginning no later than February 28, 2006, CITGO shall take the following actions for any equipment at any Covered Refinery that CITGO intends to place on the "delay of repair" list, under applicable regulations:

a. Require sign-off by the unit supervisor (as identified in the Covered Refinery's written LDAR program) 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 is technically infeasible to repair without a process unit shutdown.

b. Include equipment that is placed on the "delay of repair" list in CITGO's regular LDAR monitoring, as required in Paragraph 121.

c. Use the "drill and tap" method (or an equivalent), other than on a control or pressure relief valve, if it is leaking at a rate of 10,000 ppm or greater, unless CITGO can demonstrate that there is a safety, mechanical, or major environmental concern posed by repairing the leak in this manner. CITGO shall, if necessary, perform two "drill and taps" (or equivalents) within thirty (30) days of detecting the leak. For purposes of this Paragraph, the second attempt may be made through the same hole created during the first attempt.

d. Use best efforts to isolate and repair pumps identified as leaking at a rate of 2000 ppm or greater.

e. If a new method develops that is similarly effective as the "drill and tap" method for repairing non-control valves, CITGO will advise EPA and appropriate Co-Plaintiffs prior to implementing such new method.

129. **Chronic Leakers.** CITGO shall replace, repack, or perform similarly effective repairs on chronically leaking, non-control valves during the next process unit turnaround after

identification. A component shall be classified as a "chronic leaker" under this Paragraph if it leaks above 10,000 ppm twice in any consecutive four quarters, unless the component has not leaked in the twelve (12) consecutive quarters prior to the relevant process unit turnaround.

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

a. Consistent with the requirements of Section IX (Recordkeeping and Reporting), CITGO shall include the following information in each Covered Refinery's Semi-Annual Progress Report in which the identified activity occurred or was required:

i. Notification that training has been implemented as required by Paragraph 116;

ii. Notification that the lower leak definitions and increased monitoring frequencies have been implemented according to Paragraphs 119 and 121;

iii. Notification that the "initial attempt at repair" program under Paragraph 122 has been implemented;

iv. Notification that the QA/QC procedures for reviewing data generated by LDAR technicians under Paragraph 124 have been implemented;

v. An identification of each Covered Refinery's LDAR Coordinator;

vi. Notification that a tracking program for new valves and pumps added during maintenance and construction has been developed and is being implemented;

vii. Notification that the calibration drift assessment procedures under Paragraph 127 have been implemented;

viii. Notification that the "delay of repair" procedures under Paragraph 128 have been implemented; and

ix. A copy of each Covered Refinery's written refinery-wide LDAR program under Paragraph 115.

b. In each Covered Refinery's Progress Report submitted pursuant to Section IX, CITGO shall also include the following information on LDAR monitoring:

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;

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, the date each component was determined to be leaking at a rate greater than 10,000 ppm, the date of each drill and tap or equivalent method of repair, its associated monitoring results, and whether such activities were completed in a timely manner under Paragraph 128;

viii. the number, date and results of each initial attempt at repair, including a list of all initial attempts/remonitoring that did not occur in a timely manner under Paragraph 122; and

ix. all instances when CITGO failed to comply with the requirements in Paragraph 120.b. (Recording, Tracking, Repairing and Remonitoring Leaks).

To the extent other required reports to EPA and the appropriate Co-Plaintiff address the above information, CITGO may incorporate such other report(s) by reference in lieu of separately submitting such information under this Paragraph 130.b.

N. INCORPORATION OF CONSENT DECREE REQUIREMENTS INTO FEDERALLY ENFORCEABLE PERMITS

131. **Currently Effective Limits and Standards**. By no later than March 31, 2005, CITGO shall submit applications to the Applicable State Agency to incorporate the emission limits and standards required by the Consent Decree that are effective as of the Date of Entry of the Consent Decree into air permits (other than Title V permits) which are federally enforceable unless such permits with such limits have already been issued or applied for. Following submission of the permit application, CITGO shall cooperate with the Applicable State Agency by promptly submitting to the Applicable State Agency all available information that the Applicable State Agency seeks following its receipt of the permit application. CITGO shall file any applications necessary to incorporate the requirements of those permits into the Title V permits of the Covered Refineries.

132. **Future Limits and Standards**. By no later than thirty (30) days after the effective date or establishment of any emission limits and/or standards under Section V of this Consent Decree, CITGO shall submit applications to the Applicable State Agency to incorporate those emission limitations and/or standards into air permits (other than Title V permits) which are federally enforceable unless such permits with such limits have already been issued or applied for. Following submission of the permit application, CITGO shall cooperate with the Applicable State Agency by promptly submitting to the Applicable State Agency all available information that the Applicable State Agency seeks following its receipt of the permit application. CITGO shall file any applications necessary to incorporate the requirements of those permits into the Title V permits of the Covered Refineries.

133. **Mechanism for Title V Incorporation.** 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.

134. **Obtaining Construction Permits.** CITGO 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 this Section V and in Section VIII. To the extent that CITGO must submit permit applications for construction or installation to the Applicable State Agencies, CITGO shall cooperate with the Applicable State Agency by promptly submitting to the Applicable State Agency all available information that the Applicable State Agency seeks following its receipt of the permit application. This Paragraph 134 is not intended to prevent CITGO from applying to the Applicable State Agency for a pollution control project exemption.

VI. EMISSION CREDIT GENERATION

135. **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 CITGO to use a fraction of the CD Emissions Reductions if: (1) the emissions units for which CITGO 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 137(2).

136. **General Prohibition**. CITGO shall not generate or use any NOx, SO_2, PM, VOC, or CO emissions reductions 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.

137. **Exception to General Prohibition**. Notwithstanding the general prohibition set forth in Paragraph 136, CITGO may use 300 tons per year of NOx, 300 tons per year of SO_2 and 20 tons per year of PM 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 2 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 CITGO 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 CITGO, 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. CITGO still shall be subject to all federal and state regulations applicable to the PSD, major non-attainment and/or minor NSR permitting process.

137A. Notwithstanding the general prohibition set forth in Paragraph 136 and for purposes of NOx "offsets" under LAC 33:III.510.C.1.b.vii only, the parties agree that 50% of the NOx emissions reduction made at the Lake Charles Refinery to demonstrate compliance with Paragraphs 54, 57 and 57A [heater and boiler NOx reductions] are not "otherwise required by the Act or by state regulations," provided that such new major stationary source or major modification, as defined in LAC 33:III.509.B. is either located at the Lake Charles Refinery or is a cogeneration project in which CITGO is a participant; has or will have a federally enforceable, non-Title V permit; and that such permit contains limits which are either no less stringent than those specified in Paragraph 137(2), or determined by LDEQ (after an opportunity for consultation with EPA) under LAC 33:III.510 or other, similar authority (e.g., LAC 33:III.509).

138. **Outside the Scope of the General Prohibition**. Nothing in this Section VI is intended to prohibit CITGO from seeking to: (1) utilize or generate emissions credits or

reductions from Covered Refinery units to the extent that the proposed credits or reductions represent the difference between the emissions limitations set forth in this Consent Decree for these refinery units and the more stringent emissions limitations that CITGO may elect to accept for these refinery units in a permitting process; or (2) utilize or generate emissions credits or reductions on refinery units that are not subject to an emission limitation pursuant to this Consent Decree.

VII. MODIFICATIONS TO IMPLEMENTATION SCHEDULES

139. **Securing Permits or Approvals.**

a. For any work under Sections V or VIII of this Consent Decree that requires a federal, state and/or local permit or EPA approval (e.g., EPA approval of catalyst additives in Section V), CITGO shall be responsible for submitting in a timely fashion applications for federal, state and local permits and request for EPA approval for work and activities required so that permit or approval decisions can be made in a timely fashion. CITGO shall use its best efforts to secure EPA approvals and/or 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. If it appears that the failure of EPA or any other governmental entity to act upon a timely-submitted permit application or request for EPA approval may delay CITGO's performance of work according to an applicable implementation schedule, CITGO shall notify the EPA and the Applicable Federal and State Agencies of any such delays as soon as practicable after CITGO reasonably concludes that the delay could affect its ability to comply with the implementation schedule set forth in this Consent Decree.

b. CITGO 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 CITGO. EPA, after an opportunity for consultation with the appropriate Co-Plaintiff, shall not unreasonably withhold its consent to requests for modifications of schedules of implementation if the requirements of this Paragraph are met. All modifications to any dates initially set forth in this Decree or in any approved schedule of implementation shall be signed in writing by EPA and CITGO, and neither the United States nor CITGO shall be required to file such modifications with the Court in order for the modifications to be effective. The procedures of this Paragraph may be used more than once, if necessary. 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. The failure of EPA or an other 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; this Paragraph shall apply.

140. **Commercial Unavailability of Control Equipment and/or Additives.**

a. CITGO 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 and/or catalyst additive. If it appears that the commercial unavailability of any control equipment and/or catalyst additive may delay CITGO's performance of work according to an applicable implementation schedule, CITGO shall notify the Applicable Federal and State Agencies of any such delays as soon as practicable after CITGO reasonably concludes that the delay could affect its ability to comply with the implementation schedule set forth in this Consent Decree. CITGO 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.

b. CITGO shall propose for approval by EPA a modification to the applicable schedule of implementation, refer to this Paragraph 140 of this Consent Decree, identify the milestone date it contends it will not be able to meet, provide the Applicable Federal and State Agencies with written correspondence to the vendor identifying efforts made to secure the control equipment or catalyst additive, and describe the specific efforts CITGO has taken and will continue to take to find such equipment or additive. CITGO may propose a modified schedule or modification of other requirements of this Consent Decree to address such commercial unavailability.

c. 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 appropriate Co-Plaintiff, shall not unreasonably withhold its consent to requests for modifications of schedules of implementation if the requirements of this Paragraph are met. All modifications to any dates initially set forth in this Consent Decree or in any approved schedule of implementation shall be signed in writing by EPA and CITGO, and neither the United States nor CITGO shall be required to file such modifications with the Court in order for the modifications to be effective. The procedures of this Paragraph may be used more than once, if necessary. 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. The failure by CITGO to secure control equipment and/or catalyst additive shall not constitute a force majeure event triggering the requirements of Section XIV; this Paragraph shall apply.

VIII. ENVIRONMENTALLY BENEFICIAL PROJECTS

141. In accordance with the requirements and schedule set forth in this Section VIII, CITGO shall spend no less than $5,000,000 to implement the Supplemental Environmental Project ("SEP") described in Paragraph 142 below. CITGO may carry out its responsibilities for the SEP identified below directly or through contractors selected by CITGO.

142. The Compressor Replacement/Emissions Reduction SEP: CITGO shall no later than December 31, 2007, replace three (3) existing natural gas-fired, wet gas compressors at the Corpus Christi 1 FCCU with a single electric driven compressor, thereby eliminating emissions from the existing compressors of NOx, CO and other products generated by the combustion of natural gas.

143A. CITGO is responsible for the satisfactory completion of the SEP(s) required under this Consent Decree in accordance with this Section VIII. Upon completion of a specific SEP, CITGO shall submit to EPA and the appropriate Co-Plaintiff a cost report certified as accurate under penalty of perjury by a responsible corporate official. If CITGO does not expend the entire projected $ 5,000,000 cost of the SEP described in Paragraph 142, CITGO shall pay a stipulated penalty equal to the difference between the amount expended as demonstrated in the certified cost report(s) and the projected cost. The stipulated penalty shall be paid as provided in Paragraph 225 (Payment of Stipulated Penalties) of the Consent Decree. As an alternative to payment of the above penalty, CITGO may request approval from EPA and the appropriate Co-Plaintiff to use unexpended SEP monies for other SEPs, after an opportunity for consultation with the appropriate Co-Plaintiff.

143B. By signing this Consent Decree, CITGO certifies that it is not required, and has no liability under any federal, state or local law or regulation or pursuant to any agreements or orders of any court, to perform or develop the SEP described in Paragraph 142. CITGO further certifies that it has not applied for or received, and will not in the future apply for or receive: (1) credit as a Supplemental Environmental Project or other penalty offset in any other enforcement action for the SEP described in Paragraph 142; (2) credit for any emissions reductions resulting from the SEP described in Paragraph 142 in any federal, state or local emissions trading or early reduction program; or (3) a deduction from any federal, state, or local tax based on its participation in, performance of, or incurrence of costs related to SEP described in Paragraph 142.

143C. CITGO shall include in each Report required by Paragraph 143A, a progress report for each SEP being performed under this Section VIII of this Consent Decree. In addition, the final Report required by Paragraph 143 submitted after all SEPs identified in this Section VIII is completed, shall contain the following information with respect to each SEP:

a. A detailed description of each project as implemented;

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

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

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

143D. CITGO agrees that in any public statements regarding these SEPs, CITGO 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

144. CITGO shall submit semi-annual reports to the Applicable Federal and State Agencies that contain the following information:

a. a progress report on the implementation of the requirements of Section V (Affirmative Relief/Environmental Projects) at each Covered Refinery;

b. a summary of the emissions data, including a separate identification of any exceedence(s), for each Covered Refinery as required by Section V of this Consent Decree for the six (6) month period covered by the report;

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

d. any such additional matters as CITGO believes should be brought to the attention of the Applicable Federal and State Agencies.

e. 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 February 28, 2005. Each portion of the semi-annual report which relates to a particular Covered Refinery shall be certified by either the person responsible for environmental management and compliance for that Covered Refinery, or by a person responsible for overseeing implementation of this Decree across CITGO, as follows:

> I certify under penalty of law that this information 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. <u>CIVIL PENALTY</u>

145. Within thirty (30) days of the Date of Entry of the Consent Decree, CITGO shall pay a civil penalty of $3,600,000 as follows: (1) $ 2,300,000 to the United States; (2) $ 100,000 to the State of Georgia; (3) $ 350,000 to the State of Illinois; (4) $ 750,000 to the State of Louisiana; and (5) $ 100,000 to the State of New Jersey.

a. 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 USAO File Number 2004V01515, DOJ Case Number 90-5-2-1-07277, and the civil action case name and case number of this action in the Southern District of Texas. The costs of such EFT shall be the responsibility of CITGO. Payment shall be made in accordance with instructions provided to CITGO by the Financial Litigation Unit of the U.S. Attorney's Office for the Southern District of Texas. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. CITGO shall provide notice of payment, referencing USAO File Number 2004V01515, DOJ Case Number 90-5-2-1-07277, and the civil action case name and case number to the Department of Justice and to EPA, as provided in Paragraph 270 (Notice).

b. Payment of the civil penalty owed to the State of Georgia under this Paragraph shall be made by certified or corporate check made payable to the Georgia Department of Natural Resources and sent to the following address:

Chief
Air Protection Division
4244 International Parkway
Suite 120
Atlanta, Ga. 30354

c. Payment of the civil penalty owed to the State of Illinois under this Paragraph shall be made by certified check made payable to the Illinois 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 activities in Illinois and sent to the following address:

Phyllis Dunton
Environmental Bureau
Illinois Attorney General's Office
188 West Randolph Street, 20th Floor
Chicago, Illinois 60601

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 New Jersey under this Paragraph shall be made by certified check made payable to the State of New Jersey and sent to the following address:

Administrator, Air Compliance & Enforcement
New Jersey Department of Environmental Protection
P.O. Box 422
Trenton, New Jersey 08625-0422

146. [Intentionally Left Blank]

147. The cost of the SEPs and the civil penalty set forth herein 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, CITGO shall not treat these penalty payments as tax deductible for purposes of net income taxes imposed under federal, state, or local law.

148. Upon the Date of Entry of the Consent Decree, 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

149. CITGO shall pay stipulated penalties to the United States and the appropriate Co-Plaintiffs for each failure by CITGO to comply with the terms of this Consent Decree as provided herein. Stipulated penalties shall be calculated in the amounts specified in Paragraphs 150 through 224. 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. For those provisions where a stipulated penalty of either a fixed amount or 1.2 times the economic benefit of delayed compliance is available, the decision of which alternative to seek shall rest exclusively within the discretion of the EPA and the appropriate Co-Plaintiff.

A. Requirements for NO_X Emission Reductions from FCCUs.

150. For failure to meet the Interim NO_x Emission limits set forth in Paragraph 13, or any emissions limit proposed by CITGO or established by EPA (final or interim) for NO_X pursuant to Paragraph 19, 20, 21, 29, 30 or 30A, per day, per unit: $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.

151. For failure to prepare and/or submit written deliverables required by Paragraphs 17, 19, 20 if applicable, or 24, 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	$1000

152. For failure to timely commence, complete or substantially comply with the requirements of any minimization studies, demonstration periods, trials or studies required by Paragraphs 16, 18, and 26-29, per unit, 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	$1000

153. For failure to install, certify, calibrate, maintain, and/or operate all CEMS required by Paragraph 31, 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 delayed compliance, whichever is greater.

154. For failure to convert Corpus Christi FCCU 1 or Lemont FCCU to Full Burn Operation, as required by Paragraph 21, per unit:

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 delayed compliance, whichever is greater.

155. For failure to install Low NO_x Burners at the Lemont Refinery, as required by Paragraph 22:

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 delayed compliance, whichever is greater.

156. [Intentionally Left Blank]

B. Requirements for SO_2 Emission Reductions from FCCUs.

157. For each failure to meet SO_2 emission limits set forth in Paragraph 33, or any emission limit proposed by CITGO or established by EPA (interim or final) for SO_2 pursuant to Paragraphs 39, 40 or 40A, per day, per unit: $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.

158. For failure to prepare and/or submit written deliverables required by Paragraphs 35-42, 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	$1000

159. For failure to timely commence, complete or substantially comply with the requirements regarding the use of SO_2 Reducing Catalyst Additives, including the requirements regarding demonstration periods, short-term trials, or optimization studies, as set forth in Paragraphs 37-39, per unit, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$750
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 the delayed compliance whichever is greater

160. For failure to install, certify, calibrate, maintain, and/or operate a SO_2 CEMS, as required by Paragraph 41, per 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 delayed compliance, whichever is greater.

160A. For failure to comply with the plan required by Paragraph 42 for operating FCCUs in the event of a hydrotreater outage, per-unit, per-day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	$250
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 delayed compliance, whichever is greater.

C. Requirements for PM Emissions Reductions from FCCUs.

161. For each failure to meet any PM emission limit, as required by Paragraphs 44, 46, or, if applicable, Paragraph 45: $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 CITGO demonstrates compliance with the applicable limit.

162. For failure to submit written deliverables, or to conduct required stack tests, as required by Paragraph 47:

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

163. [Intentionally Left Blank]

D. Requirements for CO Emissions Reductions from FCCUs.

164. For each failure to meet the CO emission limits, as required in Paragraphs 48 and 49: $750 for each calendar day in a calendar quarter on which the specified 1-hour 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.

165. For failure to install, certify, calibrate, maintain, and/or operate a CO CEMS, as required by Paragraph 50, per 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 delayed compliance, whichever is greater.

E. Requirements Related to NSPS Applicability to FCCU Regenerators.

166. For failure to comply with NSPS Subparts A and J limits for SO2 or CO at each of CITGO's FCCU regenerators at the Corpus Christi, Lake Charles, and Lemont Refineries, as required by Paragraph 51, 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 of delayed compliance, whichever is greater.

F. Requirements for NOx Emission Reductions from Heaters and Boilers.

167. For failure to install selected Qualifying Controls on heaters and boilers or to reduce NOx emissions as required by Paragraphs 53, 54, 57, 57A or 58, 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 delayed compliance, whichever is greater.

168. For failure to comply with the applicable monitoring requirements as set forth in Paragraphs 59, per 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 delayed compliance, whichever is greater.

169. For failure to install, certify, calibrate, maintain, and/or operate a NOx CEMS, as required by Paragraph 60, per unit, per day:

Period of Non-Compliance	Penalty per day
1st through 30th day after deadline	\$450
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 delayed compliance, whichever is greater.

170. For failure to submit the written deliverables required by Paragraphs 55A or 56, 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	\$1,000

G. Requirements for SO_2 Emission Reductions from Heaters and Boilers.

171. For burning in any heater or boiler or in any other identified equipment listed in Appendix E any refinery fuel gas in violation of the applicable requirements of NSPS Subparts A and J after the date of Entry of the Consent Decree or, if the heater or boiler is listed in Appendix E, after the date set forth in Appendix E on which the respective unit becomes an "affected

facility" subject to NSPS Subparts A & J, as set forth in Section V.G., per unit, 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 delayed compliance, whichever is greater.

171a. For burning Fuel Oil in a manner inconsistent with the requirements of Paragraph 65, 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.

172. For failure to route all sulfur pit emissions in accordance with the requirements of Paragraph 71, per day:

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 amount of delayed compliance whichever is greater.

173. For failure to comply with the NSPS Subparts A and J emission limits at the Lemont, Lake Charles, and Corpus Christi East and West Refineries, as specified in Paragraphs 67, 68 and 69, 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 of delayed compliance, whichever is greater.

174. For failure to comply with the NSPS Subparts A and H emission limits at the Lake Charles Sulfuric Acid Plant, as specified in Paragraph 72, 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 of delayed compliance, whichever is greater.

175. For failure to comply with the monitoring requirements set forth in Paragraph 68b, per unit, 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

176. For failure to develop Preventive Maintenance and Operation Plans as specified in Paragraph 73, per unit, per day:

Period of Delay or 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

177. For failure to timely commence and complete the optimization study or to substantially comply with any of the other requirements other than installation of TGU at the Lemont Claus Trains 119 A and B, required by Paragraphs 69 and 70, per day, per requirement:

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

178. For failure to install TGUs at the Lemont Claus trains 119 A and B in compliance with Paragraph 69:

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 delayed compliance, whichever is greater.

I. Requirements for Flaring Devices.

179. For failure to comply with NSPS Subparts A and J, including emission limits, for the Flaring Devices identified in Appendix B-1 and B-2 after the compliance dates specified in Appendix G, 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 179 and 181, the provisions of Paragraph 181 shall control.

180. [Intentionally Left Blank]

J. Requirements for Control of Acid Gas Flaring and Tail Gas Incidents.

181. For AG Flaring Incidents and/or Tail Gas Incidents for which CITGO is liable under Section V.J.:

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 a 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 a Flaring Incident, the Flaring shall be deemed to commence at the time that the Flaring that triggers the initiation of a Flaring Incident commences, and shall be deemed to terminate at the time of the termination of the last episode of Flaring within the Flaring Incident. Thus, for example, for Flaring within a 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 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.

182. For failure to timely submit any report required by Section V.J., 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

183. For those corrective action(s) which CITGO: (i) agrees to undertake following receipt of an objection by EPA pursuant to Paragraph 80; or (ii) is required to undertake following dispute resolution, then, from the date of EPA's receipt of CITGO's report under Paragraph 79 of this Consent Decree until the date that either: (i) a final agreement is reached

between EPA and CITGO regarding the corrective action; or (ii) a court order regarding the corrective action is entered, CITGO shall be liable for stipulated penalties as follows:

a.

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

b. 1.2 times the economic benefit resulting from CITGO's failure to implement the corrective action(s).

184. For failure to complete any corrective action under Paragraph 80 of this Decree in accordance with the schedule for such corrective action agreed to by CITGO or imposed on CITGO pursuant to the dispute resolution provisions of this Decree (with any such extensions thereto as to which EPA and CITGO 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.

185. For each failure to perform a Root Cause analysis or submit a written report or perform corrective actions for a Hydrocarbon Flaring Incident, as required by Paragraph 94:

Period of Delay or 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 Benzene Waste NESHAP Program Enhancements. For each violation in which a frequency is specified in Section V.L., the amounts identified below shall apply on the first day of violation, shall be calculated for each incremental period of violation (or portion thereof), and shall be doubled beginning on the fourth consecutive, continuing period of violation. For requirements where no frequency is specified, penalties will not be doubled.

186. For failure to complete the BON Compliance Review and Verification Reports as required by Paragraph 98:

$7,500 per month, per refinery.

187. For failure to submit a plan that provides for actions necessary to correct non-compliance as required by Paragraph 100(b) or (c), or for failure to implement the actions necessary to correct non-compliance and to certify compliance as required by Paragraph 100(d) and 100(e), 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 delayed compliance, whichever is greater.

188. [Intentionally Left Blank]

189. [Intentionally Left Blank]

190. For failure to comply with the requirements set forth in Paragraph 101 related to the use, monitoring, and replacement of carbon canisters: $1,000 per incident of non-compliance, per day.

191. For failure to implement the training requirements of Paragraph 105: $10,000 per quarter.

192. For failure to establish an annual review program to identify new benzene waste streams as required by Paragraph 102: $2,500 per month, per refinery.

193. For failure to perform laboratory audits as required by Paragraph 103: $5,000 per month, per audit.

194. For failure to submit or maintain any plans or other deliverables required by Paragraph 106 (Waste/Slop/Off Spec Oil Management): $2,000 per deliverable.

195. [Intentionally Left Blank]

196. For failure to conduct sampling in accordance with the sampling plans required by Paragraph 107 and 108: $30,000 per quarter, per stream, whichever is greater, but not to exceed $150,000 per quarter, per refinery.

197. For failure to submit the plans or retain the third-party contractor required by Paragraph 110: $10,000 per month.

198. For failure to conduct monthly visual inspections of all Subpart FF water traps as required by Paragraph 111(a): $500 per drain not inspected;

199. For failure to identify/mark segregated stormwater drains as required in Paragraph 111(b): $1,000 per week per drain;

200. For failure to monitor Subpart FF conservation vents as required by Paragraph 111(c): $500 per vent not monitored;

201. For failure to conduct monitoring of oil-water separators as required by Paragraph 111(d): $1,000 per month, per unit.

202. For failure to submit any of the written deliverables required by Section V.L. (except for those deliverables for which stipulated penalties are specified in Paragraphs 186, 187, 194 or 197) - $1,000 per week, per deliverable.

203. If it is determined through a federal, state, or local investigation that any Covered Refinery has failed to include all benzene-containing waste streams in its TAB calculation submitted pursuant to Paragraph 98, CITGO shall pay the following, per waste stream:

Waste Stream	Penalty
for waste streams < 0.03 Mg/yr	$250
for waste streams between 0.03 and 0.1 Mg/yr	$1,000
for waste streams between 0.1 and 0.5 Mg/yr	$5,000
for waste streams > 0.5 Mg/yr	$10,000

M. <u>Requirements for Leak Detection and Repair Program Enhancements.</u> For each violation in which a frequency is specified in Section V.M., the amounts identified below shall apply on the first day of violation, shall be calculated for each incremental period of violation (or portion thereof), and shall be doubled beginning on the fourth consecutive, continuing period of violation. For requirements where no frequency is specified, penalties will not be doubled.

204. [Intentionally Left Blank]

205. For failure to develop an LDAR Program as required by Paragraph 115: $3,500 per week, per refinery.

206. For failure to implement the training programs specified in Paragraph 116: $10,000 per month, per program, per refinery.

207. For failure to conduct any of the audits described in Paragraph 117: $5,000 per month, per audit, per refinery.

208. For failure to implement any actions necessary to correct non-compliance as required in Paragraph 118:

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 delayed compliance, whichever is greater

209. For failure to perform monitoring utilizing the lower internal leak rate definitions as specified in Paragraph 119: $100 per component, but not greater than $10,000 per month, per process unit.

210. For failure to make first repair attempts within 5 days and/or take other actions required by Paragraph 120: $100 per component but not greater than $10,000 per month, per refinery (except that Paragraph 211 shall apply in lieu of this Paragraph 210 where both paragraphs are potentially applicable).

211. For failure to implement the "initial attempt" repair program set forth in Paragraph 122: $100 per component, but not to exceed $10,000 per month, per process unit.

212. For failure to implement the QA/QC procedures described in Paragraph 124: $1,000 per incident, but not greater than $10,000 per month per process unit.

213. For failure to implement the LDAR monitoring program as required by Paragraph 121: $100 per component, but not greater than $10,000 per month, per process unit.

214. For failure to designate an individual as accountable for LDAR performance as required by Paragraph 115g, or for failure to implement the maintenance tracking program required by Paragraph 115d: $3,500 per week per refinery.

215. For failure to use dataloggers or maintain electronic data as required by Paragraph 123: $5,000 per month.

216. 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 127: $100 per missed event.

217. For failure to comply with the requirements for delay of repair set forth at Paragraph 128: $5,000 per valve or pump, per incident of non-compliance.

218. For failure to submit the written deliverables required by Section V.M.: $500 per week per deliverable.

219. For each valve or pump that CITGO failed to include in its LDAR program within ninety (90) days of the date of completion of the initial audit under Paragraph 117, CITGO shall pay $175. If it is determined through a federal, state, or local investigation that CITGO has failed to include all valves or pumps in its LDAR program, CITGO shall pay $225 per component that it failed to include.

220. For failure to comply with the requirements for chronic leakers set forth at Paragraph 129: $5,000 per valve.

N. Requirements to Incorporate Consent Decree Requirements into Federally-Enforceable Permits.

221. For each failure to submit an application as required by Paragraphs 131 and 132:

Period of Non-Compliance	Penalty per day
Days 1-30	$800
Days 31-60	$1,500
Over 60 Days	$3,000

O. Requirements for Reporting and Recordkeeping.

222. 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

P. Requirements for Environmentally Beneficial Projects and Civil Penalties.

223. For failure to timely complete implementation of the SEPs required under Section VIII, per project, per day:

Period of Delay or 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

Q. Requirement to Pay Stipulated Penalties.

224. For failure to pay stipulated penalties as required by Paragraph 225 of this Consent Decree, CITGO 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).

R. Payment of Stipulated Penalties.

225. CITGO shall pay stipulated penalties upon written demand by the United States or the appropriate Co-Plaintiffs, no later than sixty (60) days after CITGO receives such demand. Demand from either the United States or the appropriate Co-Plaintiffs shall be deemed a demand from both, but the United States and the appropriate Co-Plaintiffs shall consult with each other prior to making a demand. Stipulated penalties owed by CITGO shall be paid 50 percent to the United States and 50 percent to the appropriate Co-Plaintiffs. Stipulated penalties shall be paid to the United States and the appropriate Co-Plaintiffs 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 appropriate 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 appropriate Co-Plaintiff may, in their unreviewable discretion, waive payment of any portion of stipulated penalties that may accrue under this Consent Decree. Payment of stipulated penalties shall relieve CITGO from liability to EPA and appropriate Co-Plaintiff from civil penalties under its permits for the same violation.

S. **Stipulated Penalties Dispute.**

226. Should CITGO dispute the United States' and/or the appropriate Co-Plaintiffs' 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 224 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 225 for payment of stipulated penalties. If the dispute is thereafter resolved in CITGO's favor, the escrowed amount plus accrued interest shall be returned to CITGO; otherwise, the United States and the appropriate 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 appropriate 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 CITGO's violations of this Consent Decree.

XII. INTEREST

227. After the date on which a payment is due under this Consent Decree, CITGO 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 Paragraph 227, 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 226 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

228. Any authorized representative of an Applicable Federal or State Agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of the facilities of the Covered Refineries, 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 CITGO

pursuant to the requirements of this Consent Decree or in the ordinary course of CITGO's business that are deemed necessary by EPA or the applicable Co-Plaintiff to verify compliance with this Consent Decree. CITGO 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 an Applicable Federal or State Agency to conduct tests, inspections, or other activities under any statutory or regulatory provision.

XIV. FORCE MAJEURE

229. If any event occurs which causes or may cause a delay or impediment to performance in complying with any provision of this Consent Decree, CITGO shall notify the Applicable Federal and State Agencies in writing as soon as practicable, but in any event within ten (10) business days of the date when CITGO first knew of the event or should have known of the event by the exercise of due diligence. In this notice, CITGO shall specifically reference this Paragraph 229 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 CITGO to prevent or minimize the delay and the schedule by which those measures shall be implemented. CITGO 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 the Applicable EPA Regional Office as specified in Paragraph 270 (Notice).

230. Failure by CITGO to substantially comply with the notice requirements of Paragraph 229 as specified above shall render this Section XIV (Force Majeure) voidable by the United States, in consultation with the Applicable State Agency, as to the specific event for

which CITGO has failed to comply with such notice requirement, and, if voided, is of no effect as to the particular event involved.

231. The United States, after consultation with the Applicable State Agency, shall notify CITGO 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 229.

232. If the United States, after consultation with the Applicable State Agency, agrees that the delay or impediment to performance has been or will be caused by circumstances beyond the control of CITGO, including any entity controlled by CITGO, and that CITGO 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. CITGO shall not be liable for stipulated penalties for the period of any such delay.

233. If the United States, after consultation with the Applicable State Agency, does not accept CITGO's claim of a delay or impediment to performance, CITGO 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 appropriate Co-Plaintiff do not agree, the position of the United States on the force majeure claim shall become the final Plaintiffs' position. Once CITGO has submitted this matter to the Court, the United States and the Applicable State Agency 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 CITGO, including any entity controlled by CITGO, and that the delay could not have been prevented by CITGO by the exercise of due diligence, CITGO 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.

234. CITGO shall bear the burden of proving that any delay of 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. CITGO 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.

235. Unanticipated or increased costs or expenses associated with the performance of CITGO'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.

236. 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 CITGO serving a force majeure notice or the Parties' inability to reach agreement.

237. 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. CITGO 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

238. 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/Environmental Projects) 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 of this Consent Decree (Termination).

239. 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.

240. 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.

241. 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.

242. In the event that the Parties are unable to reach agreement during such informal negotiation period, the United States or the Applicable State Agency, as applicable, shall provide CITGO with a written summary of its position regarding the dispute. The position advanced by the United States or the Applicable State Agency, as applicable, shall be considered binding unless, within forty-five (45) calendar days of CITGO's receipt of the written summary of the United States' or the Applicable State Agency's position, CITGO files with the Court a petition which describes the nature of the dispute. The United States or the Applicable State Agency shall respond to the petition within forty-five (45) calendar days of filing.

243. In the event that the United States and the Applicable State Agency make differing determinations or take differing actions that affect CITGO's rights or obligations under this Consent Decree, the determination or action of the United States shall control.

244. 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.

245. 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.

246. 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. CITGO 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

247. **Definitions**. For purposes of 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, all 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); Title 40, Part 51, Appendix S; and 40 C.F.R. § 52.24, all as amended from time to time; and

(iii) Any applicable state 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. "Post-Lodging Compliance Dates" shall mean any dates in this Section XVI after the Date of Lodging. Post-Lodging Compliance Dates include dates certain (e.g., "December 31, 2005"), dates after Lodging represented in terms of "months after Lodging" (e.g., "Twelve

Months after the Date of Lodging"), 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.

248. **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 CITGO to the United States and the Co-Plaintiffs for violations of the Applicable NSR/PSD Requirements resulting from construction or modification from the date of the pre-Lodging construction or modification (including reconstruction) up to the following dates:

Unit	Pollutant	Date
Lemont FCCU	SO_2	December 31, 2007
	NOx	March 31, 2013
	PM	December 31, 2007
	CO	Date of Entry
Lake Charles FCCU A	SO_2	March 31, 2012
	NOx	March 31, 2012
	CO	October 1, 2005
	PM	March 31, 2010
Lake Charles FCCU B	SO_2	December 31, 2006
	NOx	September 30, 2010
	PM	December 31, 2006
	CO	October 31, 2005
Lake Charles FCCU C	SO_2	December 31, 2007
	NOx	September 30, 2010
	PM	December 31, 2007
	CO	October 31, 2005

Corpus Christi FCCU # 1	SO_2 NOx PM CO	September 30, 2013 September 30, 2013 December 31, 2006 Date of Entry
Corpus Christi FCCU # 2	SO_2 NOx CO PM	March 31, 2010 August 31, 2007 Date of Entry April 30, 2005
All Heaters and Boilers listed in Appendix C	NOx	June 30, 2011
All Heaters and Boilers other than those in Appendix C	NOx	Date of Lodging
All Heaters and Boilers listed in Appendix E	SO_2	Dates listed in Appendix E
All Heaters and Boilers other than those listed in Appendix E	SO_2	Date of Lodging
All Fuel Gas Combustion Devices listed in Appendix F	SO_2	Dates listed in Appendix F
All Flaring Devices listed in Appendices B-1 or B-2, and G	SO2	Date listed in Appendix G
Lake Charles Sulfuric Acid Plant	SO2	December 31, 2006

249. **Reservation of Rights regarding Applicable NSR/PSD Requirements: Release for Violations Continuing After the Date of Lodging Can be Rendered Void.** Notwithstanding the resolution of liability in Paragraph 248, the release of liability by the United States and the Co-Plaintiffs to CITGO for 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 CITGO materially fails to comply with the obligations and requirements of Sections V.A. - V.D. and V.F. for that unit; provided however, that the release in Paragraph 248 shall not be rendered void if CITGO remedies such material failure and pays any stipulated penalties due as a result of such material failure.

250. **Exclusions from Release Coverage regarding Applicable NSR/PSD Requirements: Construction and/or Modification Not Covered by Paragraph .** Notwithstanding the resolution of liability in Paragraph 248, nothing in this Consent Decree precludes the United States and/or the Co-Plaintiffs from seeking from CITGO, injunctive relief, penalties, or other appropriate relief for violations by CITGO of the Applicable NSR/PSD Requirements resulting from construction or modification that: (1) 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 (2) commences after the Date of Lodging of the Consent Decree for units covered by this Consent Decree.

251. 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 the Covered Refineries, are beyond the scope of the release in Paragraph 248.

252. **Resolution of Liability Regarding Applicable NSPS Requirements.** With respect to emissions of the following pollutants from the following units, entry of this Consent Decree shall resolve all civil liability of CITGO to the United States and the Co-Plaintiffs for violations of the Applicable NSPS Subparts A and J Requirements from the date that the claim(s) of the United States and the Co-Plaintiffs accrued up to the following dates:

Unit	Pollutant	Date
All Covered FCCUs	SO_2	Dates listed in Paragraph 248
	PM (including opacity)	Dates listed in Paragraph 248
	CO	Dates listed in Paragraph 248
All Heaters and Boilers listed in Appendix E	SO_2	Dates listed in Appendix E
All Heaters and Boilers other than those listed in Appendix E	SO_2	Date of Lodging
All Fuel Gas Combustion Devices listed in Appendix F	SO_2	Dates listed in Appendix F
Corpus Christi East and Corpus Christi West SRPs	SO2	Date of Entry
Lake Charles SRP	Total Reduced Sulfur	Date of Entry
Lemont SRP	SO_2	December 31, 2008
Flaring Devices listed in Appendices B-1 or G	SO_2	Date listed in Appendix G

In addition and with respect to the Lake Charles Refinery sulfuric acid plant, entry of this Consent Decree shall resolve all civil liability of CITGO to the United States and the State of Louisiana for violations of the Applicable NSPS Subparts A and H requirements from the date the claim(s) of the United States and the State of Louisiana accrued up to December 31, 2006.

253. **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 Paragraph 252, the release of liability by the United States and the Co-Plaintiffs to CITGO for violations of any

Applicable NSPS Subparts A and J Requirement that occurred between the Date of Lodging and the Post-Lodging Compliance Dates shall be rendered void for a particular emissions unit if CITGO materially fails to comply with the obligations and requirements of Sections V.E., V.G., V.H., V.I., V.J. and V.K., and Paragraphs 44-46 and 48-49 for that unit; provided however, that the release in Paragraph 252 shall not be rendered void if CITGO remedies such material failure and pays any stipulated penalties due as a result of such material failure.

254. **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.

255. **Resolution of Liability Regarding Benzene Waste NESHAP Requirements.** With respect to the National Emission Standard for Benzene Waste Operations, 40 C.F.R. Part 61, Subpart FF ("Benzene Waste NESHAP"), and any applicable state, regional, or local regulations that implement, adopt or incorporate the Benzene Waste NESHAP, entry of this Consent Decree shall resolve all civil liability of CITGO to the United States and the Co-Plaintiffs for violations that: (1) commenced and ceased prior to the Date of Entry of the Consent Decree; and/or (2) are based on events identified in the BON Compliance Review and Verification Report required under Paragraph 98 and are corrected pursuant to the requirements of Paragraph 100.

256. **Resolution of Liability Regarding LDAR Requirements**. With respect to the Leak Detection and Repair requirements relating to equipment in light liquid service and gas and/or vapor service set forth at 40 C.F.R. Part 60, Subparts VV and GGG; 40 C.F.R. Part 61,

Subparts J and V; and 40 C.F.R. Part 63, Subparts F, H, and CC (collectively "LDAR Requirements"), and any applicable state, regional, or local regulations or State Implementation Plan requirements that implement, adopt or incorporate the LDAR Requirements or set similar standards, entry of this Consent Decree shall resolve the civil liability of CITGO to the United States and the Co-Plaintiffs for violations that: (1) commenced and ceased prior to the Date of Entry of the Consent Decree; and/or (2) are based on events identified in the initial audit required under Paragraph 117(a) and are corrected pursuant to the requirements of Paragraph 118.

257. **Reservation of Rights Regarding the Benzene Waste NESHAP and LDAR Requirements**. Notwithstanding the resolution of liability in Paragraphs 255 and 256, nothing in this Consent Decree precludes the United States and/or the Co-Plaintiffs from seeking from CITGO civil penalties and/or injunctive relief and/or other equitable relief for violations by CITGO of Benzene Waste NESHAP and/or LDAR requirements that: (1) commenced prior to the Date of Entry of this Consent Decree and continued after the Date of Entry if CITGO fails to identify in its Paragraph 98 report or its Paragraph 117(a) audit, as applicable, such violations, and/or fails to correct such violations pursuant to Paragraphs 100 or 118, as applicable; or (2) commenced after the Date of Entry of the Consent Decree but are not identified in CITGO's Paragraph 98 report or its Paragraph 117(a) audit, as applicable and/or are not corrected pursuant to Paragraphs 100 or 118, as applicable.

258. With respect to the claims which formed the basis of the notices and orders identified in Appendix A, the United States and the Co-Plaintiffs release CITGO from any and

all civil liability under the Clean Air Act and any corresponding state or local laws or regulations arising out of any acts or omissions by CITGO which formed the basis for such claims.

258A. With respect to any claims for a stipulated penalty under this Consent Decree, assessment of and payment of such stipulated penalty by CITGO shall resolve all civil liability of CITGO to the United States and the Co-Plaintiffs under the Clean Air Act and any similar state or local laws or regulations, for any and all violations based on the facts or circumstances giving rise to the claim for and assessment of the stipulated penalty.

259. **Audit Policy.** Nothing in this Consent Decree is intended to limit or disqualify CITGO, 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 CITGO discovers during the course of any investigation, audit, or enhanced monitoring that CITGO is required to undertake pursuant to this Consent Decree.

260. **Claim/Issue Preclusion.** In any subsequent administrative or judicial proceeding initiated by the United States or the Co-Plaintiffs for injunctive relief, penalties, or other appropriate relief relating to CITGO for 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. CITGO 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 CITGO assert, or maintain, any other defenses based upon any contention that the claims raised by the United States or the 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 CITGO to assert that the claims are deemed resolved by virtue of this Section XVI of the Consent Decree.

b. The United States and 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 CITGO of any interpretation or guidance issued by EPA related to the matters addressed in this Consent Decree.

261. **Imminent and Substantial Endangerment.** Nothing in this Consent Decree shall be construed to limit the authority of the United States, Georgia, Illinois, Louisiana, or New Jersey to undertake any action against any person, including CITGO, to abate or correct conditions which may present an imminent and substantial endangerment to the public health, welfare, or the environment.

XVII. GENERAL PROVISIONS

262. **Other Laws.** Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve CITGO of its obligations to comply with all applicable federal, state and local laws and regulations. Subject to Section XVI, nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the United States, Georgia, Illinois, Louisiana, or New Jersey to seek or obtain other remedies or sanctions available under other federal, state or local statutes or regulations, by virtue of CITGO's violation of the Consent Decree or of the statutes and regulations upon which the Consent Decree is based, or for CITGO's violations of any applicable provision of law, other than the specific matters resolved herein. This shall include the right of the United States, Georgia, Illinois, Louisiana, or New

Jersey to invoke the authority of the Court to order CITGO's compliance with this Consent Decree in a subsequent contempt action.

263. **Post-Permit Violations.** Nothing in this Consent Decree shall be construed to prevent or limit the right of the United States, Georgia, Illinois, Louisiana, or New Jersey to seek injunctive or monetary relief for violations of permits issued as a result of the procedure required under Section V.N. of this Decree; provided however, that with respect to monetary relief, the United States, Georgia, Illinois, Louisiana, or New Jersey 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).

264. **Failure of Compliance.** The United States, Georgia, Illinois, Louisiana, or New Jersey do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that CITGO's complete compliance with the Consent Decree will result in future compliance with the provisions of the CAA, the Georgia Air Quality Act, OCGA 12-9-1; the Illinois Environmental Protection Act, 415 ILCS 5/8: Title II Air Pollution; Louisiana Air Control Law, LSA - R.S. 30:2051-2065; the New Jersey Air Pollution Control Act, 26:2C-1 to 25.2; and the Texas Clean Air Act, Acts 1989, 71st Leg., ch. 382. Notwithstanding the review or approval by EPA or the Co-Plaintiffs, including their applicable state agencies, of any plans, reports, policies or procedures formulated pursuant to the Consent Decree, CITGO 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).

265. **Service of Process.** CITGO 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 CITGO at Paragraph 270 (Notice) are authorized to accept service of process with respect to all matters arising under or relating to the Consent Decree.

266. **Post-Lodging/Pre-Entry Obligations**. Obligations of CITGO under this Consent Decree to perform duties scheduled to occur after the Date of Lodging of the Consent Decree, but prior to the Date of Entry of the Consent Decree, shall be legally enforceable on and after the Date of Entry of the Consent Decree. 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, Georgia, Illinois, Louisiana, and/or New Jersey 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 Date of Entry of the Consent Decree may not be collected unless and until this Consent Decree is entered by the Court.

267. **Costs**. Each Party to this action shall bear its own costs and attorneys' fees.

268. **Public Documents**. All information and documents submitted by CITGO to the Applicable Federal and State Agencies 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.

269. **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 Co-Plaintiff, the State of Louisiana, through the Department of Environmental Quality, and entry of this Consent Decree is subject to the requirements of La. R.S. 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 CITGO facilities are located, an opportunity for public comment, consideration of any comments, and concurrence by the State Attorney General.

270. **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 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 CITGO shall be submitted as specified in this Consent Decree, with copies to EPA Headquarters and the Applicable EPA Region and the Applicable State Agency. 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 Co-Plaintiffs and/or CITGO 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. 90-5-2-1-07277

As to EPA:

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

EPA Region 2:

Director, Division of Enforcement and Compliance Assistance
U.S. Environmental Protection Agency, Region 2
21st Floor
290 Broadway
New York, NY 10007

Chief, Air Compliance Branch
Division of Enforcement and Compliance Assistance
21st Floor
290 Broadway
New York, NY 10007

EPA Region 4:

Chief, Air Enforcement & EPCRA Branch
Air, Pesticides and Toxics Management Division
U.S. Environmental Protection Agency, Region 4
61 Forsyth Street, S.W.
Atlanta, Georgia 30303

EPA Region 5:

Air and Radiation Division
U.S. EPA, Region 5
77 West Jackson Blvd. (AE-17J)
Chicago, Illinois 60604
ATTN: Compliance Tracker

Office of Regional Counsel
U.S. EPA, Region 5
77 West Jackson Blvd. (C-14J)
Chicago, Illinois 60604

EPA Region 6:

Chief
Air, Toxics, and Inspections Coordination Branch
Environmental Protection Agency, Region 6
1445 Ross Avenue
Dallas, Texas 75202-2733

The State of Georgia:

Chief
Air Protection Branch
Environmental Protection Division
4244 International Parkway
Suite 120
Atlanta, Ga. 30354

The State of Illinois:

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

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

The State of New Jersey:

New Jersey Department of Environmental Protection
Southern Regional Office
Air Compliance & Enforcement Manager
One Port Center
2 Riverside Drive, Suite 201
Camden, New Jersey 08103

As to CITGO:

Manager, Environmental Services
CITGO
1293 Eldridge Parkway
Houston, Texas 77077

General Counsel
CITGO
1293 Eldridge Parkway
Houston, Texas 77077

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. In addition, the nature and frequency of reports required by the Consent Decree may be modified by mutual consent of the Parties. The consent of the United States to such modification must be in the form of a written notification of consent from the Department of Justice, but need not be filed with the Court to be effective.

271. **Approvals.** All EPA approvals shall be made in writing. All Plaintiff-Intervener approvals shall be sent from the offices identified in Paragraph 270.

272. **Paperwork Reduction Act.** The information required to be maintained or submitted pursuant to this Consent Decree is not subject to the Paperwork Reduction Act of 1980, 44 U.S.C. §§ 3501 et seq.

273. **Modification.** 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, including modifications to the schedules for catalyst additive programs under Sections V.A and V.B and to the frequency of reporting obligations, shall be in writing, signed by the Parties, but need not be filed with the Court. Material modifications to this Consent Decree shall be in writing, signed by the Parties, and shall be effective upon filing with the Court.

XVIII. TERMINATION

274. This Consent Decree shall be subject to termination upon motion by the United States, in consultation with the Co-Plaintiffs, or CITGO (under the procedure identified in Paragraph 276). Prior to either party seeking termination, CITGO shall have completed and satisfied all of the following requirements of this Consent Decree:

a. installation of control technology systems as specified in this Consent Decree;

b. compliance with all provisions contained in this Consent Decree, which compliance may be established for specific parts of the Consent Decree in accordance with Paragraph 275, below;

c. 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 Co-Plaintiffs;

d. completion of the "environmentally beneficial" projects set forth in Section VIII;

e. application for and receipt of permits incorporating the surviving emission limits and standards established under Section V.N.; and

f. 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.

275. **Certification of Completion**.

a. Prior to moving for termination, CITGO may certify completion of one or more of the following subsections of the Consent Decree, provided that all of the related requirements have been satisfied:

i. Subsection V.A. - V.E.; relating to FCCUs;

ii. Subsections V.F. - V. G., relating to Heaters, Boilers and Other Fuel Gas Combustion Devices;

iii. Subsections V.H - V.K, relating to SRPs and Flaring;

iv. Subsections V.L and V.M, relating to Benzene Waste NESHAP and LDAR; and

v. Section VIII, relating to Environmentally Beneficial Projects.

b. Within 90 days after CITGO concludes that any of the parts of the Consent Decree identified in this Paragraph 275 have been completed, CITGO may submit a written report to the Parties listed in Paragraph 270 (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 CITGO 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 CITGO:

> 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 CITGO's certification, EPA, after reasonable opportunity for review and comment by the Applicable State Agencies, shall notify CITGO 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 CITGO'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 CITGO as to the activities that must be undertaken to complete the applicable Paragraphs of the Consent Decree. CITGO 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 CITGO. This certification shall constitute the certification of completion of the applicable Paragraphs for purposes of this Consent Decree.

d. Nothing in Paragraph 275(c) shall preclude the United States or the Co-Plaintiffs 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 275 of the Consent Decree. In addition, nothing in Paragraph 275(c) shall permit CITGO 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 275 of the Consent Decree.

276. At such time as CITGO believes that it has satisfied the requirements for termination set forth in Paragraph 274, CITGO shall certify such compliance and completion to the United States and the Co-Plaintiffs in writing as provided in Paragraph 270 (Notice). Unless, within 120 days of receipt of CITGO's certification under this Paragraph, either the United States or the Co-Plaintiffs objects in writing with specific reasons, CITGO may move this Court for an order that this Consent Decree be terminated. If either the United States or the Co-Plaintiffs objects to the certification by CITGO 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, CITGO shall bear the burden of proving that this Consent Decree should be terminated.

XIX. SIGNATORIES

277. 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 __________, 2004

____
UNITED STATES DISTRICT JUDGE

PLANTIFF UNITED STATES OF AMERICA

Tom Sansonetti
THOMAS L. SANSONETTI
Assistant Attorney General
Environment and Natural Resources Division
U.S. Department of Justice
Washington, DC 20530

9.22.04
DATE

Nicholas F. Persampieri
NICHOLAS F. PERSAMPIERI
Trial Attorney
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611
Washington, DC 20044-7611

9/16/04
DATE

Thomas V. Skinner
THOMAS V. SKINNER
Acting Assistant Administrator for Enforcement
and Compliance Assurance
United States Environmental Protection Agency
1200 Pennsylvania Avenue, Mail Code: 2201A
Washington, DC 20460

9.8.04
DATE

PLAINTIFF THE STATE OF GEORGIA

Date: SEPT 21, 2004

CAROL A. COUCH, PH.D.
Director
Environmental Protection Division
Department of Natural Resources
State of Georgia

PLAINTIFF THE STATE OF ILLINOIS

Rose Marie Cazeau

Date: 8/25/04

ROSEMARIE CAZEAU
Chief
Environmental Bureau
Assistant Attorney General
188 West Randolph St. 20th Floor
Chicago, Illinois 60601

PLAINTIFF THE STATE OF LOUISIANA, THROUGH THE DEPARTMENT OF ENVIRONMENTAL QUALITY:

HAROLD LEGGETT, Ph.D. Date: 8/27/04

Assistant Secretary
Office of Environmental Compliance
Louisiana Department of Environmental Quality

TED R. BROYLES Date: 8-26-04

Senior Attorney (LA Bar No: 20456)
Legal Division
Louisiana Department of Environmental Quality
(225) 219-3985

PLAINTIFF THE STATE OF NEW JERSEY

PETER C. HARVEY
Attorney General of New Jersey

By Scott B Dubin

SCOTT B. DUBIN
Deputy Attorney General
Department of Law and Public Safety
Division of Law
RJ Hughes Justice Complex
25 Market St. 7th Floor West
P.O. Box 093
Trenton, NJ 08648-0093

Date: 9/23/04

EDWARD M. CHOROMANSKI
Administrator, Air Compliance & Enforcement
New Jersey Department of Environmental Protection
P.O. Box 422
401 East State Street, Floor 4
Trenton, New Jersey 08625

Date: 9/23/04

DEFENDANT CITGO PETROLEUM CORPORATION

By Jerry E Thompson

Date: 8/20/04

JERRY E. THOMPSON
Chief Operating Officer

DEFENDANT CITGO REFINING AND CHEMICALS COMPANY, L.P.

By______________________ Date: Aug 23, 04
FRANK GYGAX
President

DEFENDANT PDV MIDWEST REFINING, L.L.C.

By Jerry E Thompson Date: 8/20/04
JERRY E. THOMPSON
President

DEFENDANT CITGO ASPHALT REFINING COMPANY

By______________________ Date: 8/23/04

President

APPENDIX A

STATE AND FEDERAL COMPLIANCE ORDERS AND NOTICES

EPA FOV 5-99-IL-28 (dated 6-8-99)

EPA NOV 5-01-IL-04 (dated 1-19-01)

EPA FOV 5-01-IL-11 (dated 7-13-01)

IEPA Violation Notice A-2002-00346 (dated 11/13/02)

IEPA Violation Notice E-2003-00004 (dated 1-13-03)

LDEQ Notice of Violation and Potential Penalty AE-NP-99-0226 (dated 10-29-99)

LDEQ Compliance Order and Notice of Potential Penalty AE-CN-01-0304 (dated 6-6-02)

LDEQ Compliance Order and Notice of Potential Penalty AE-CN-02-0191 (dated 3-10-03)

TCEQ Agreed Order Docket No. 2001-1469-AIR-E (dated February 2004)

TNRCC Agreed Order Docket No. 1999-0057-AIR-E (dated June 2002)

APPENDIX B

LIST OF HYDROCARBON FLARING DEVICES

Corpus Christi East Refinery

Fluor Flare

Cumene Flare

Corpus Christi West Refinery

Flare

Lemont Refinery

844C-1 North Plant Flare

844C-2 South Plant Block 2 Flare

844C-3 South Plant Block 3 Flare

844C-4 Needle Coker Flare

844C-5 Alky Flare

Lake Charles Refinery

328B-1 Flare Alky

330B-4 Flare NGL/Girbitol

343B-5 Flare Central

343B-6 Flare Central

343B-7 Flare Central

319B-8 Flare C4 Recovery

315B-9 Flare Benzene

327B-11 Flare C-Ref/CK II

320B-12 Flare Unicracker

399B-16 Flare CFH

360CB-701 (CB-11) PFU

CA1001 CLAW

B-104 COP/TIER II

Paulsboro Refinery

Flare

APPENDIX B-1

LIST OF NSPS HYDROCARBON FLARING DEVICES

Corpus Christi East Refinery

Fluor Flare

Cumene Flare

Corpus Christi West Refinery

Flare

Lemont Refinery

844C-1 North Plant Flare

844C-2 South Plant Block 2 Flare

844C-3 South Plant Block 3 Flare

844C-4 Needle Coker Flare

844C-5 Alky Flare

Lake Charles Refinery

327B-11 Flare C-Ref/CK II

320B-12 Flare Unicracker

399B-16 Flare CFH

360CB-701 (CB-11) PFU

CA1001 CLAW

B-104 COP/TIER II

Paulsboro Refinery

Flare

APPENDIX B-2

LIST OF NSPS ACID GAS FLARING DEVICES

Corpus Christi East Refinery

Acid Gas Flare

SWS Flare

Corpus Christi West Refinery

Acid Gas Flare

SWS Flare

Lemont Refinery

844C-2 South Plant Block 2 Flare

844C-3 South Plant Block 3 Flare

Lake Charles Refinery

327B-11 Flare C-Ref/CK II

320B-12 Flare Unicracker

APPENDIX C

LIST OF CITGO HEATERS AND BOILERS

INFORMATION REDACTED AS CONFIDENTIAL BUSINESS INFORMATION

	SEQ No.	Unit ID	Heat Input Capacity, MMBTU/Hr Design/Permit	2001 NOx Emissions, TPY	2002 NOx Emissions, TPY	2001 EIQ Firing Rate MMBTU/Hr	2002 EIQ Firing Rate MMBTU/Hr	2001 Utilization Percentage	2002 Utilization Percentage	NOx Emission Factor, Basis
	LAKE CHARLES REFINERY									
	79	Boiler B-1,B-1A	890.6	2461.8	2493.3	803.0	813.2	Redacted	Redacted	F&TS Testing
	145	Furnace B-503,504,505	700.0	172.9	197.7	415.6	475.1	Redacted	Redacted	Stack Test (Permit - 2615(M-2))
	77	Boiler B-1C	616.7	474.9	505.5	349.8	372.3	Redacted	Redacted	F&TS Testing
√	78	Boiler B-1B	531.6	450.3	471.0	374.5	391.7	Redacted	Redacted	AP-42
√	25	Furnace B-4	456.6	242.6	218.9	403.5	364.2	Redacted	Redacted	AP-42
	26	Furnace B-104	456.6	280.1	289.9	456.8	472.8	Redacted	Redacted	F&TS Testing
	135	Boiler B-5A	337.6	81.3	76.5	185.6	174.7	Redacted	Redacted	Stack Test (PSD-LA-577)
	136	Boiler B-5	337.6	92.9	89.6	212.1	204.6	Redacted	Redacted	Stack Test (PSD-LA-577)
	87	Furnace B-403,404,405	330.0	46.7	54.7	183.8	215.3	Redacted	Redacted	F&TS Testing
	80	Boiler B-2	267.1	193.4	181.2	160.9	150.7	Redacted	Redacted	AP-42
	81	Boiler B-2A	267.1	132.6	117.8	168.2	149.4	Redacted	Redacted	F&TS Testing
	141	Furnace B-1,2,3,4,5	245.0	119.8	136.1	134.7	153.1	Redacted	Redacted	Stack Test (Permit - 2615(M-2))
	82	Boiler B-3,B-3B	229.5	303.9	309.5	252.8	257.4	Redacted	Redacted	AP-42
	83	Boiler B-3A,B-3C	229.5	155.0	153.7	128.9	127.8	Redacted	Redacted	AP-42
	144	Furnace B-501,502,506	198.5	73.3	69.8	88.2	83.9	Redacted	Redacted	Stack Test (PSD-LA-222)
√	107	Furnace B-102 - B-106	185.0	92.2	65.6	76.7	54.6	Redacted	Redacted	AP-42
	34	Boiler BF-4	167.0	45.0	0.0	37.4	0.0	Redacted	Redacted	AP-42
	139	Furnace B-201	158.8	110.7	93.3	158.0	133.2	Redacted	Redacted	F&TS Testing
√	140	Furnace B-202	158.8	90.5	87.1	150.6	144.8	Redacted	Redacted	AP-42
√	48	A Cat Furnace B-6	156.2	100.4	94.4	83.5	78.5	Redacted	Redacted	AP-42
	50	C Cat Furnace B-6	156.2	24.5	29.1	68.3	80.9	Redacted	Redacted	F&TS Testing
	31	Boiler BF-1	139.0	114.3	138.8	95.1	115.4	Redacted	Redacted	AP-42
	32	Boiler BF-2	139.0	124.6	140.9	103.7	117.2	Redacted	Redacted	AP-42
	33	Boiler BF-3	139.0	136.4	134.5	113.4	111.9	Redacted	Redacted	AP-42
	177	Furnace B-101	116.9	18.0	13.0	97.6	70.6	Redacted	Redacted	Stack Test (Permit - 2308(M-2))
	14	Furnace BA-1,2A&2B	115.6	102.2	110.5	85.0	91.9	Redacted	Redacted	AP-42
	69	Furnace B-101	112.9	70.0	92.4	85.7	101.3	Redacted	Redacted	2001 - AP-42/ 2002 - Stack Test (Permit - 2714(VO))
	70	Furnace B-201	109.7	74.6	92.1	91.3	101.0	Redacted	Redacted	2001 - AP-42/ 2002 - Stack Test (Permit - 2714(VO))
	94	Furnace B-1C	104.7	134.5	143.7	111.8	119.5	Redacted	Redacted	AP-42
	95	Furnace B-2C	98.2	47.0	46.4	109.4	108.1	Redacted	Redacted	AP-42
	178	Furnace B-102	88.0	14.4	10.7	78.4	58.4	Redacted	Redacted	Stack Test (Permit - 2308(M-2))
	49	B Cat Furnace B-6	81.4	16.6	15.2	38.6	35.5	Redacted	Redacted	AP-42
	1	Furnace BA-1	77.5	33.4	37.4	77.8	87.1	Redacted	Redacted	AP-42
	2	Furnace BA-101	77.5	33.5	23.1	78.0	70.3	Redacted	Redacted	2001 - AP-42 2002 - AP-42 - Low Nox burner
	65	Furnace B-201	75.6	41.7	44.3	97.1	103.2	Redacted	Redacted	AP-42
	72	Furnace B-101	74.8	22.0	23.3	51.2	54.3	Redacted	Redacted	AP-42
	73	Furnace B-101 #2	74.8	22.0	23.3	51.2	54.3	Redacted	Redacted	AP-42
	19	Furnace BA-1 & 2	68.3	11.3	11.3	26.4	26.2	Redacted	Redacted	AP-42
	63	Furnace B-201	64.8	22.2	24.9	51.8	58.0	Redacted	Redacted	AP-42
	6	Furnace N-2A	64.7	20.2	20.3	47.1	47.2	Redacted	Redacted	AP-42
	7	Furnace N-2B	64.7	23.2	21.1	54.0	49.2	Redacted	Redacted	AP-42
	8	Furnace N-2C	64.7	21.1	20.9	49.2	48.7	Redacted	Redacted	AP-42
	17	Furnace BA-1 & 2	64.6	19.9	20.1	46.3	46.8	Redacted	Redacted	AP-42
	84	Furnace B-401	60.4	17.5	15.7	40.8	36.5	Redacted	Redacted	AP-42
	74	Furnace B-5	58.4	14.0	14.2	32.5	33.1	Redacted	Redacted	AP-42
	85	Furnace B-406	57.3	10.6	11.5	24.8	26.7	Redacted	Redacted	AP-42
	86	Furnace B-402	55.9	14.3	16.2	33.3	37.8	Redacted	Redacted	AP-42
	64	Furnace B-202	53.0	18.3	16.6	42.7	38.7	Redacted	Redacted	AP-42
	66	Furnace B-2A	44.5	19.6	21.1	45.8	49.1	Redacted	Redacted	AP-42
	91	Furnace B-102	43.3	27.7	23.3	40.1	33.7	Redacted	Redacted	Stack Test (Permit - 74(M-3))
	67	Furnace B-1 #1	39.0	24.2	22.4	56.3	52.1	Redacted	Redacted	AP-42
	68	Furnace B-1 #2	39.0	24.2	22.4	56.3	52.1	Redacted	Redacted	AP-42
		Totals	9543	7039	7106					

√

Those units identified with this checkmark are to be tested for NOx emissions. With prior consent from EPA, CITGO may substitute any other heater or boiler with a design firing rate > 100 MMBtu/hr and for which AP-42 factors are currently being used to estimate the baseline NOx emissions.

APPENDIX C

LIST OF CITGO HEATERS AND BOILERS

INFORMATION REDACTED AS CONFIDENTIAL BUSINESS INFORMATION

	Unit ID	Heat Input Capacity, MMBTU/Hr Design/Permit	1999 NOx Emissions, TPY	2000 NOx Emissions, TPY	1999 Firing Rate MMBTU/Hr	2000 Firing Rate MMBTU/Hr	1999 Utilization Percentage	2000 Utilization Percentage	NOx Emission Factor, Basis
LEMONT REFINERY									
	430B-1	325.0	181.7	198.9	183.9	201.3	Redacted	Redacted	Previously used AP-42, 5th ed. (3/98), Table 1.4-2 (factor =0.274351 lb./MMBtu). 10/10/01 stack testing by ARI resulted in current factor.
	111B-1A	322.0	250.0	261.1	277.2	289.6	Redacted	Redacted	Based on 10/9/2000 stack test by ARI
	111B-1B	322.0	234.2	250.2	259.8	277.5	Redacted	Redacted	Based on 10/9/2000 stack test by ARI
	431B-19	249.0	37.8	39.0	118.8	122.6	Redacted	Redacted	Previously used AP-42, 5th ed. (3/98), Table 1.4-2 (factor = 0.27451 lb./MMBtu). 9/6/01 stack testing by ARI resulted in current factor.
	431B-Replacement	249.0	0.0	0.0	0.0	0.0	Redacted	Redacted	Replacement for 431B-19 in 2002. Designed for 0.06 lb. NOx/MMBtu.
	111B-2	219.8	104.8	38.5	148.6	145.9	Redacted	Redacted	4/22/98 stack test = 0.161 lb/MMBtu. ULNB installed March '00. EF = 0.06 lb/MMBtu (est). 10/19/2000 stack test by ARI showed EF = 0.036 lb./MMBtu.
	116B-1	125.6	103.8	104.1	86.3	86.6	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	123B-2	121.2	91.9	104.4	76.4	86.8	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	112B-1	121	0.0	0.0	0.0	0.0	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	116B-2	106.9	129.2	104.0	107.5	86.5	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	109B-62	103.0	37.6	64.9	53.7	92.6	Redacted	Redacted	Permit Basis is 0.16 lb./MMBtu. AP 42, 5th ed. (3/98), Table 1.4-2 is 0.098039.
	118B-1	93.8	18.9	22.2	44.0	51.7	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	113B-1	88.8	16.38	16.1	71.9	70.8	Redacted	Redacted	required by SEP. 9/97 stack test
	113B-2	88.8	15.8	15.6	69.5	68.5	Redacted	Redacted	Permit, 9/97 stack test of 113B-1
	113B-3	88.8	26.8	27.4	71.7	73.2	Redacted	Redacted	Permit, 10/85 stack test results
	125B-2	82.3	40.4	37.0	94.0	86.2	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	125B-1	69.3	31.6	13.2	73.5	30.8	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	123B-3	55.3	9.9	10.2	23.2	23.8	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	123B-1	45.6	7.9	9.9	18.3	23.0	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	123B-5	42.0	12.8	12.2	29.9	28.4	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
	Totals	2919	1352	1329					

APPENDIX C

LIST OF CITGO HEATERS AND BOILERS

INFORMATION REDACTED AS CONFIDENTIAL BUSINESS INFORMATION

	Unit ID	Heat Input Capacity, MMBTU/Hr Design/Permit	2001 NOx Emissions, TPY	2002 NOx Emissions, TPY	2001 EIQ Firing Rate MMBTU/Hr	2002 EIQ Firing Rate MMBTU/Hr	2001 Utilization Percentage	2002 Utilization Percentage	NOx Emission Factor, Basis	
CORPUS CHRISTI REFINERY										
	East Plant	320	59.9	47.3	173.8	171.4	Redacted	Redacted	NOx CEM	
	East Plant	311.8	94.9	105.4	154.7	171.9	Redacted	Redacted	AP-42	
	East Plant	120	39.3	38.6	118	116.1	Redacted	Redacted	Stack Test (5/99)	
	East Plant	219	82.6	99.4	99.2	119.5	Redacted	Redacted	AP-42	
	East Plant	121.7	80.9	88.9	97.2	106.8	Redacted	Redacted	AP-42	
	East Plant	223	16.7	14.5	95.9	108.3	Redacted	Redacted	NOx model	
	East Plant	116	40.3	44.4	92.1	101.4	Redacted	Redacted	AP-42	
	East Plant	200.6	41.9	43.5	79.5	78.2	Redacted	Redacted	NOx model	
	East Plant	252.4	120.7	142.4	232.3	196.8	Redacted	Redacted	AP-42	Note 1
	East Plant	48	19.4	19.2	44.2	43.9	Redacted	Redacted	AP-42	
	East Plant	41.6	13.2	12.7	30.1	29	Redacted	Redacted	AP-42	
	East Plant	164.3	0.0	0.0	0.0	0.0	Redacted	Redacted	AP-42	
	East Plant	400	130.4	132.2	391.6	397.1	Redacted	Redacted	Stack Test (5/99)	
	East Plant	52.8	10.5	3.9	23.9	15.8	Redacted	Redacted	AP-42	
	East Plant	52.8	10.1	4.1	23	16.3	Redacted	Redacted	AP-42	
	West Plant	290.6	45.0	47.8	205.4	222.4	Redacted	Redacted	NOx model	
	West Plant	144.8	74.4	71.6	121.4	116.8	Redacted	Redacted	AP-42	
	West Plant	132.7	58.2	62.1	94.9	101.2	Redacted	Redacted	AP-42	
	West Plant	76.6	32.6	31.8	74.4	72.7	Redacted	Redacted	AP-42	
	West Plant	82.3	27.9	29.4	67.7	71.5	Redacted	Redacted	Stack Test (1/15/98)	
	West Plant	98.9	25.7	21.8	50.2	42.5	Redacted	Redacted	Stack Test (3/26/84)	
	West Plant	98.9	21.6	20.3	46	43.4	Redacted	Redacted	Stack Test (3/22/84)	
	West Plant	48.2	19.4	20.9	44.4	47.7	Redacted	Redacted	AP-42	
	West Plant	98.9	17.2	17.4	39.3	39.8	Redacted	Redacted	AP-42	
	West Plant	49.9	15.9	13.7	36.2	31.3	Redacted	Redacted	AP-42	
	West Plant	62	7.5	7.7	26.5	27.1	Redacted	Redacted	Stack Test (1/16/98)	
	East Plant	16.2	197.5	201.3	20.8	20.4	Redacted	Redacted	AP-42	Note 1
	East Plant	59.4	166.6	154.1	12	11.1	Redacted	Redacted	AP-42	
	East Plant	11.1	1.6	1.6	1.62	1.62	Redacted	Redacted	AP-42	
	Totals	3915	1472	1498						

Note 1: Utilizes YR 2000 NOx emissions and Firing Rate for baseline for the #4 Platformer and the Platformer Compressors.

Heat Input Capacity, MMBTU/Hr	2001 NOx Emissions, TPY	2002 NOx Emissions, TPY
16,377	9,862	9,933

APPENDIX D

DETERMINING THE OPTIMIZED ADDITION RATES OF CATALYST ADDITIVES AT THE FCCUs

I. PURPOSE

This Appendix defines a process by which CITGO shall determine for the FCCUs the Optimized Addition Rates for Low NOX Combustion Promoters, NOX Reducing Catalyst Additives and SO2 Reducing Additives during the Optimization Periods.

II. ESTABLISHING AN OPTIMIZED LOW NOX COMBUSTION PROMOTER ADDITION RATE

A. Overview. Establishing an Optimized Low NOX Combustion Promoter Addition Rate for the FCCUs is a three-step process: (1) establishing a minimum addition rate for the conventional combustion promoter that CITGO currently uses such that the effectiveness of the conventional combustion promoter is maintained (the "Minimum Conventional Combustion Promoter Addition Rate"); (2) replacing the conventional combustion promoter with a particular Low NOX Combustion Promoter at an addition rate that is the functional equivalent of the Minimum Conventional Combustion Promoter Addition Rate (the "Initial Low NOX Combustion Promoter Addition Rate"); and (3) increasing the addition rate up to two times the Initial Low NOX Combustion Promoter Addition Rate if the Initial Low NOX Combustion Addition Rate is not effective (the "Optimized Low NOX Combustion Promoter Addition Rate").

B. "Effectiveness" Determinations. The effectiveness of conventional combustion promoter shall be determined by the following criteria: (1) afterburn is controlled adequately and regenerator temperature and combustion levels are adequately maintained; and

(2) temperature excursions are brought under control adequately. The effectiveness of Low NOX Combustion Promoter shall be determined by those two criteria and by whether a measurable reduction in NOX emissions occurs.

C. <u>Establishing the Minimum Conventional Combustion Promoter Addition Rate.</u> CITGO shall reduce its historical usage of conventional combustion promoters to the point that the addition rate is the minimum necessary to retain the effectiveness of the conventional combustion promoter that CITGO is using ("Minimum Conventional Combustion Promoter Addition Rate").

D. <u>Establishing the Initial Low NOX Combustion Promoter Addition Rate</u>. Based on the activity of conventional combustion promoter historically used and the activity of the Low NOX combustion promoter, CITGO shall replace conventional combustion promoter with Low NOX Combustion Promoter at a rate that is the functional equivalent in promotion activity of the Minimum Conventional Combustion Promoter Addition Rate. This functionally equivalent rate shall be called the Initial Low NOX Combustion Promoter Addition Rate.

E. <u>Establishing the Optimized Low NOX Combustion Promoter Addition Rate</u>. If the Low NOX Combustion Promoter is not effective at the Initial Low NOX Combustion Promoter Addition Rate, CITGO shall increase, by up to two times, the Initial Low NOX Combustion Promoter Addition Rate. If, at two times the Initial Low NOX Combustion Promoter Addition Rate, the Low NOX Combustion Promoter is not effective, CITGO may discontinue the use of Low NOX Combustion Promoter.

III. ESTABLISHING AN OPTIMIZED NOX REDUCING CATALYST ADDITIVE ADDITION RATE

A. Overview. The Optimized NOX Reducing Catalyst Additive Addition Rate shall be determined by evaluating NOX emissions reductions and annualized costs at three different addition rates.

B. The Increments. The three addition rates or "increments" shall be:

1.0 Weight % NOX Reducing Catalyst Additive
1.5 Weight % NOX Reducing Catalyst Additive
2.0 Weight % NOX Reducing Catalyst Additive

Where Weight % is of the total catalyst added to the FCCU.

C. The Procedure. CITGO shall successively add NOX Reducing Catalyst Additive at each increment set forth above. Once a steady state has been achieved at each increment, CITGO shall evaluate the performance of the NOX Reducing Catalyst Additive in terms of NOX emissions reductions and projected annualized costs. The final Optimized NOX Reducing Catalyst Additive Addition Rate shall occur at the addition rate where either:

(1) the FCCU meets 20 ppmvd NOX (corrected to 0% O2) on a 365-day rolling average, in which case CITGO shall agree to accept limits of 20 ppmvd NOX (corrected to 0% O2) on a 365-day rolling average basis at the conclusion of the Demonstration Period; or

(2) the total annualized cost-effectiveness of the NOX Reducing Catalyst Additive used exceeds $10,000 per ton of NOX removed as measured from an uncontrolled baseline (as estimated based on current operating parameters as compared to operating parameters during the baseline period); or

(3) the Incremental NOX Reduction Factor is less than 1.8, where the Incremental NOX Reduction Factor is defined as:

$$\frac{PR_i - PR_{i-1}}{CAR_i - CAR_{i-1}}$$ where:

PR_i = Pollutant (NOX) reduction rate at increment i in pounds per day from the baseline model

PR_{i-1}	=	Pollutant (NOX) reduction rate at the increment prior to increment i in pounds per day from the baseline model
CAR_i	=	NOX Reducing Catalyst Additive Rate at increment i in pounds per day
CAR_{i-1}	=	NOX Reducing Catalyst Additive Rate at the increment prior to increment i in pounds per day

If the conditions of either (1), (2), or (3) above are not met at any addition rate less than 2.0 Weight % NOX Reducing Catalyst Additive, then the Optimized Addition Rate shall be 2.0 Weight % NOX Reducing Catalyst Additive.

If an additive limits the FCCU's ability to control CO emissions to below 500 ppmvd CO at 0% O2 on an 1-hour basis or 100 ppmvd CO at 0% Ox on a 365-day basis, and cannot be reasonably compensated for by adjusting other parameters without adversely impacting conversion (yield selectivity) or processing rates, then the additive rate shall be reduced to a level at which the additive no longer causes such effects.

IV. ESTABLISHING AN OPTIMIZED SO2 REDUCING CATALYST ADDITIVE ADDITION RATE

A. Overview. The Optimized SO2 Reducing Catalyst Additive Addition Rate shall be determined by evaluating SO2 emissions reductions and annualized costs at three different addition rates.

B. The Increments. The three addition rates or "increments" shall be:

5.0 Weight % SO2 Reducing Catalyst Additive
7.5 Weight % SO2 Reducing Catalyst Additive
10.0 Weight % SO2 Reducing Catalyst Additive

Where Weight % is of the total catalyst added to the FCCU.

C. The Procedure. CITGO shall successively add SO2 Reducing Catalyst Additive at each increment set forth above. Once a steady state has been achieved at each increment, CITGO shall evaluate the performance of the SO2 Reducing Catalyst Additive in terms of SO2 emissions reductions. The final Optimized SO2 Reducing Catalyst Additive Addition Rate shall occur at the addition rate where either:

(1) the FCCU meets 25 ppmvd SO2 (corrected to 0% O2) on a 365-day rolling average and 50 ppmvd SO2 (corrected to 0% O2) on a 7-day rolling average, in which case CITGO shall agree to accept limits of 25 ppmvd SO2 (corrected to 0% O2) on a 365-day rolling average and 50 ppmvd SO2 (corrected to 0% O2) on a 7-day rolling average at the conclusion of the Demonstration Period;

(2) the addition of SO_2 Reducing Catalyst Additive limits the FCCU feedstock processing rate or conversion (yield selectivity) capability in a manner that cannot be reasonably compensated for by the adjustment of other parameters, then the maximum addition rate shall be reduced to a level at which the additive no longer interferes with the FCCU processing or conversion rate; provided, however, that in no case, shall the maximum addition rate be less than 5.0 weight %; or

(3) the Incremental SO2 Pick-up Factor is less than 2.0, where the Incremental SO2 Pick-up Factor is defined as:

$$\frac{PR_i - PR_{i-1}}{CAR_i - CAR_{i-1}}$$ where:

PR_i = Pollutant (SO2) reduction rate at increment i in pounds per day from the baseline model

PR_{i-1} = Pollutant (SO2) reduction rate at the increment prior to increment i in pounds per day from the baseline model

CAR_i = Pollutant (SO2) Reducing Catalyst Additive Rate at increment i in pounds per day

CAR_{i-1} = Pollutant (SO2) Reducing Catalyst Additive Rate at the increment prior to increment i in pounds per day

If the conditions of either (1), (2), or (3) above are not met at any addition rate less than 10.0 weight % SO2 Reducing Catalyst Additive, then the Optimized Addition Rate shall be 10.0 weight % SO2 Reducing Catalyst Additive. In no case shall the Optimized Addition Rate shall be less than 5.0 weight % SO_2 Reducing Catalyst Additive.

APPENDIX E

NSPS SUBPART J COMPLIANCE SCHEDULE

FOR HEATERS AND BOILERS AND STREAMS IN FUEL GAS

Plant	Unit	Completion/Submittal Date
Corpus Christi East Refinery	Cumene Depropanizer Off-Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Hydrar Stabilizer OH Off Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Hydrar Stripper Off Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Hydrar Hydrogen	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Hydrar Degassing Drum Off Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	C4SHP DME Stripper Off Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Tanks 140 and 141 Vents	AMP 6 months after Date of Entry
Corpus Christi East Refinery	C5 Merox Disulfide Separator Spent Air Vent	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Unibon Recycle Hydrogen Purge	AMP 6 months after Date of Entry
Corpus Christi West Refinery	Merox Disulfide Separator Spent Air Vent	AMP 6 months after Date of Entry
Lemont Refinery	114B-1	July 2005
Lemont Refinery	114B-2	July 2005
Lemont Refinery	114B-3	July 2005
Lemont Refinery	115B-1	July 2005
Lemont Refinery	115B-2	July 2005
Lemont Refinery	116B-1	July 2005
Lemont Refinery	116B-2	July 2005
Lemont Refinery	116B-3	July 2005
Lemont Refinery	116B-4	July 2005
Lemont Refinery	118B-1	July 2005

Plant	Unit	Completion/Submittal Date
Lemont Refinery	118B-51	July 2005
Lemont Refinery	122B-1	July 2005
Lemont Refinery	122B-2	July 2005
Lemont Refinery	123B-1	October 2005
Lemont Refinery	123B-2	October 2005
Lemont Refinery	123B-3	October 2005
Lemont Refinery	123B-4	October 2005
Lemont Refinery	123B-5	October 2005
Lemont Refinery	125B-1	July 2005
Lemont Refinery	125B-2	July 2005
Lake Charles Refinery	C-Reformer B-501	March 2005
Lake Charles Refinery	C-Reformer B-502	March 2005
Lake Charles Refinery	C-Reformer B-503	March 2005
Lake Charles Refinery	C-Reformer B-504	March 2005
Lake Charles Refinery	C-Reformer B-505	March 2005
Lake Charles Refinery	C-Reformer B-506	March 2005
Lake Charles Refinery	Boiler BF-1	September 2005
Lake Charles Refinery	Boiler BF-2	September 2005
Lake Charles Refinery	Boiler BF-3	September 2005
Lake Charles Refinery	Boiler BF-4	September 2005
Lake Charles Refinery	Boiler BF-5	September 2005
Lake Charles Refinery	Duo-Sol Furnace N-2A	September 2005
Lake Charles Refinery	Duo-Sol Furnace N-2B	September 2005
Lake Charles Refinery	Duo-Sol Furnace N-2C	September 2005
Lake Charles Refinery	Duo-Sol Furnace S-1	September 2005
Lake Charles Refinery	Duo-Sol Furnace S-2	September 2005
Lake Charles Refinery	Duo-Sol Furnace P-2	September 2005
Lake Charles Refinery	Furfural Furnace BA-1,2A&2B	September 2005
Lake Charles Refinery	Furfural Furnace BA-3	September 2005
Lake Charles Refinery	MEK-1 Furnace BA-1 & 2	September 2005
Lake Charles Refinery	MEK-2 Furnace BA-1 & 2	September 2005
Lake Charles Refinery	MEK-2 Furnace BA-3	September 2005
Lake Charles Refinery	Lube Vaccum BA-1	AMP by February 2010
Lake Charles Refinery	Lube Vacuum BA-101	AMP by September 2011
Lake Charles Refinery	TAME Hydrogen	Unit Shutdown. If restarted, AMP by startup date.

Plant	Unit	Completion/Submittal Date
Lake Charles Refinery	C Dock Butane Unloading	AMP by December 2005

APPENDIX F

FUEL GAS COMBUSTION DEVICES COMPLIANCE SCHEDULE

Plant	**Unit Stream**	**AMP Submittal Date**
Corpus Christi East Refinery	Marine Emission Control	6 months after Date of Entry
Corpus Christi East Refinery	NESHAP FF Incinerator	6 months after Date of Entry
Corpus Christi East Refinery	CPI Vapor Combustor	6 months after Date of Entry
Lemont Refinery	333B-401 Barge Dock Benzene Vapor Combustor	6 months after Date of Entry
Lemont Refinery	335B-1 Fuels Rack Emission Control	6 months after Date of Entry
Lake Charles Refinery	B-700 WWT Combustor	June 2007
Lake Charles Refinery	B-13 A-Dock Vapor Combustor	December 2005
Lake Charles Refinery	B-14 B&C Dock Vapor Combustor	December 2005
Lake Charles Refinery	B-15 D Dock Vapor Combustor	December 2005
Lake Charles Refinery	VCU-01 Fuel Loading Rack Combustor	December 2005
Paulsboro Refinery	Marine Emission Combustor	August 2008

APPENDIX G

NSPS SUBPART J COMPLIANCE SCHEDULE FOR NSPS FLARING DEVICES

Plant	Flare	Completion /Submittal Date
Corpus Christi East Refinery	Cumene Flare	December 2007
Corpus Christi East Refinery	Fluor Flare	December 2007
Corpus Christi East Refinery	Acid Gas Flare	AMP by 6 months after Date of Entry
Corpus Christi East Refinery	SWS Flare	AMP by 6 months after Date of Entry
Corpus Christi West Refinery	Flare (*)	December 2006
Corpus Christi West Refinery	Acid Gas Flare	AMP by 6 months after Date of Entry
Corpus Christi West Refinery	SWS Flare	AMP by 6 months after Date of Entry
Lemont Refinery	844C-1 North Plant Flare	Date of Entry
Lemont Refinery	844C-2 South Plant Block 2 Flare (*)	Date of Entry
Lemont Refinery	844C-3 South Plant Block 3 Flare (*)	Date of Entry
Lemont Refinery	844C-4 Needle Coker Flare(*)	Date of Entry
Lemont Refinery	844C-5 Alky Flare	AMP by 6 months after Date of Entry
Lake Charles Refinery	327B-11 Flare C-Ref/CK II(*)	September 2010
Lake Charles Refinery	320B-12 Flare Unicracker	February 2010
Lake Charles Refinery	399B-16 Flare CFH	December 2008
Lake Charles Refinery	360CB-701 (CB-11) PFU	AMP by December 2005
Lake Charles Refinery	CA1001 CLAW	AMP by June 2007
Lake Charles Refinery	B-104 COP/TIERII	December 2011
Paulsboro Refinery	Flare	AMP by August 2006

(*) Identifies flares for which CITGO will install equipment to minimize hydrocarbon flaring from coker blowdown cycles under Paragraph 94.

APPENDIX H

PREDICTIVE EMISSIONS MONITORING SYSTEMS FOR HEATERS AND BOILERS WITH CAPACITIES BETWEEN 150 AND 100 mmBTU/HR

A Predictive Emissions Monitoring Systems ("PEMS") is a mathematical model that predicts the gas concentration of NOx 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. COPC will identify and use existing instruments and refinery data sources to provide sufficient data for the development and implementation of the PEMS.

Instrumentation:

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.

Computers & Software:

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.

Calibration and Setup:

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.

The elements of a monitoring protocol for a PEMS will include:

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 CFR 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.

DATED: DECEMBER 7, 1999; SIGNED: JOHN B. RASNIC

Phillip E. Guillemette
Director of Environmental Affairs
Koch Refining Company LP
P.O. Box 64596
Saint Paul, Minnesota 55164-0596

Dear Mr. Guillemette:

This is in response to your August 14, 1998, and January 6, 1999, letters to Administrator Carol Browner, and your July 9, 1999, supplemental submittal. Please find enclosed, our December 2, 1999, response addressing applicability issues of the New Source Performance Standards NSPS Subpart J to refinery fuel gases and fuel gas combustion devices. Also enclosed is our general "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gases" addressing your request for approval of an alternative plan to continuous monitoring of refinery fuel gases.

While your July 9, 1999, supplemental submittal and the September 3, 1999, letter from Mr. James Mahoney, your Senior Vice President of Operations, request that we approve a proposed flare management policy, we are unable to do so at this time. We continue to review the issue. We appreciate your willingness to meet with us to answer questions on these difficult issues, and hope we can work out a resolution that provides clarification for what the Environmental Protection Agency considers to be "good air pollution control practice for minimizing emissions" under NSPS Subpart J for flare systems. As we continue to work on an agreement for a flaring policy, based on our past discussions with representatives from Koch, we believe that many of your current and planned practices to minimize flaring events (assuming proper documentation of those practices) are elements of "good air pollution control" and provide adequate protection of human health and the environment.

I trust that the enclosed information will be useful to you. If you have any questions, please feel free to contact Tom Ripp of my staff at (202) 564-7003.

Sincerely,

s/ JOHN B. RASNIC

John B. Rasnic, Director
Manufacturing, Energy and Transportation Division
Office of Compliance

Enclosures

cc: James Mahoney, Koch
Preparedby:t.ripp:mlw:12/3/99:2:30 PM:2pp:564-7003:2223A:**kochco~1.wpd**

DATED: DECEMBER 2, 1999; SIGNED: KEN GIGLIELLO for

Phillip E. Guillemette
Director of Environmental Affairs
Koch Refining Company LP
P.O. Box 64596
Saint Paul, Minnesota 55164-0596

Dear Mr. Guillemette:

This is in response to your August 14, 1998, and January 6, 1999, letters to Administrator Browner. Koch Refining Company LP (Koch) seeks clarification from the Environmental Protection Agency (EPA) regarding the applicability of New Source Performance Standard Subpart J (NSPS Subpart J) to: fuel gas combustion devices (FGCDs) and fuel gases; "process upset" conditions; and to certain identified gas streams at its Rosemount, Minnesota refinery. Although you requested that EPA review and revise NSPS Subpart J in your August 14, 1998, letter, it is our current understanding that you are not requesting that NSPS Subpart J be reviewed/revised as part of a response to your letters.

You write that NSPS Subpart J is, in part, intended to reduce sulfur emissions from gases generated as a byproduct of the refining process that are used as fuel in a refinery's heaters and boilers. To accomplish this, NSPS Subpart J imposes monitoring requirements and limits for certain fuel gas streams that are combusted in refinery FGCDs. You assert that "fuel gas" and "FGCD" are vaguely defined, and it is often unclear as to what types of units and streams are covered under the standard. We disagree with your characterization that "fuel gas" and "FGCD" are not clearly defined. The definitions are purposefully broad, and the exemptions are specific. We also disagree with your characterizations that the rule is limited to only refinery generated gases burned as fuel in refinery process heaters and boilers. The rule clearly includes routine combustion of refinery gases in flares and other waste gas disposal devices.

In your letter, you develop a position on exemptions from NSPS Subpart J based on the commendable use of a flare gas recovery system. You describe your refinery flare gas recovery system, and state that:

> . . . [a]s designed, the flare gas recovery system has sufficient capacity to recover gases that are routed to the system under normal operating conditions . . . . . Under process upset conditions, the flare gas recovery system's capacity may be exceeded and excess gases are routed to the flare for combustion . . . .

Because you believe that your refinery gases are routed to the flare only as a result of process upsets, you believe that the flaring of those gases are not subject to NSPS Subpart J. We do not agree that all of the events you describe as "process upset conditions" meet the regulatory definition of malfunction or the interpretation of "upset", and, therefore, may not be qualified for exemption from NSPS Subpart J. In addition, we note that any malfunction or upset involving combustion of process upset gas in an NSPS-affected FGCD would still be subject to NSPS Subpart A (General Provisions) §60.11(d) obligations.

Your August 14, 1998, letter focuses on three areas:

- How NSPS Subpart J applies to FGCDs and fuel gases;
- How the process upset gas exemption applies;
- How NSPS Subpart J applies to the 26 miscellaneous gas streams.

Our response addresses those issues in order.

How NSPS Subpart J Applies to FGCDs and Fuel Gases

The provisions of NSPS Subpart J are, in part, applicable to affected FGCDs. To control sulfur oxide (SO_x) emissions to the atmosphere from affected FGCDs, NSPS Subpart J §60.104(a)(1) limits the amount of hydrogen sulfide (H_2S) allowed in the fuel gas burned in those devices. Except for fuel gas released to a flare as a result of relief valve leakage or other emergency malfunctions, you must not burn fuel gas containing greater than 230 mg/dscm of H_2S in any affected FGCD. Additionally, the combustion of a process upset gas in a FGCD is exempt from the H_2S limit. The combustion/flaring of those exempted gases in an NSPS-affected FGCD is still subject to §60.11(d) of the General Provisions as described later.

NSPS Subpart J §60.104(a)(1) applies to gas combustion devices, if the following are true:

1) The gas is a "fuel gas" [§60.101(d)]:

> . . . any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners.

2) The fuel gas is combusted in a "FGCD" [§60.101(g)]:

> . . . any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

3) The FGCD is an "affected FGCD". An affected FGCD is any FGCD for which construction or modification commenced after June 11, 1973. §60.100(b)

Additionally, when determining the applicability of NSPS Subpart J to any particular combination of combustion device and gas stream, the following general concepts apply:

- Unlike the definition of process upset gas, the definition of fuel gas does not require that the gas be generated by a "refinery process unit", it must merely be generated at the refinery;

- There is no general exemption for gas streams with low sulfur content;

- There is no general exemption for low volume or intermittent gas streams;

- A FGCD need not generate a product to be regulated. Flares do not generate products or energy that are recovered for use, but they are clearly FGCDs since they are specifically named in the definition.

Your refinery flares (constructed after June 11, 1973) are affected FGCDs as defined by NSPS Subpart J. When the capacity of your refinery flare gas recovery system is exceeded as the result of normal operations (not malfunctions), NSPS Subpart J for FGCDs applies to those NSPS refinery flares.

For any fuel gas stream subject to NSPS Subpart J, you may petition for alternative monitoring under the General Provisions at §60.13(i). For EPA to approve alternative monitoring, you must submit sufficient information to show that your alternative monitoring plan will yield similar results to the required monitoring under NSPS Subpart J.

How the Process Upset Gas Exemption Applies

As mentioned above, §60.104(a)(1) exempts the combustion in a FGCD of process upset gases and exempts the combustion in a flare of fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunction. Not all of the events you describe as "process upset conditions" meet the qualifications for exemption from NSPS Subpart J. Therefore, the 26 gas streams do not receive a blanket exemption from the regulation. Some of the gases generated under Koch's described events are not gases generated as a result of upsets, but are generated as a result of normal operations. Additionally, not all of your process upsets result in flaring.

Process upset gas is defined at §60.101(e) as:

> . . . any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

Malfunction is defined in the General Provisions at §60.2 as:

> . . . any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Upset is not defined in NSPS Subpart J or in the General Provisions. However, in EPA's 1973 Background Information for Proposed New Source Performance Standards for Petroleum Refineries, PB-221 736 (1973 BID), page 25, EPA writes that the proposed standard does not apply to extraordinary situations, such as emergency gas releases. In EPA's 1974 Background Information for New Source Performance Standards for Petroleum Refineries, PB-231 601 (1974 BID), page 20, EPA further explained the statement in the 1973 BID that:

> Because the frequency of process upsets and the volumes of gases which must be disposed of are highly unpredictable, it is not feasible to design or operate a gas treating facility that would prevent sulfur dioxide emissions from flare systems in these situations. A facility designed to remove hydrogen sulfide from all process upset gases prior to combustion would have to be designed to handle the immediate release of gases from all process units if each unit experienced the worst possible upset or malfunction at the same time. The cost of such a large gas treatment facility would impose a severe and unreasonable economic burden upon a refinery.

From the language in the 1974 BID, it is clear that a facility does not have to be designed to treat and dispose of gases produced in a worst case scenario at a facility. However, it is clear that more frequent and predicable process events (which Koch would describe as "upsets", but which do not meet the interpretation for upsets) are subject to the standard, and that it is not unreasonable for the facility to have sufficient capacity to handle these routine process events.

In a similar issue, EPA successfully argued in a case before an Administrative Law Judge (ALJ), that the term "system breakdown" (which is used in 40 CFR §60.13(e), but is undefined) was akin to a malfunction as defined in the General Provisions at §60.2. In the March 9, 1995, decision (see Enclosure 1), the ALJ wrote that:

> While the actual words "system breakdown" do not appear here [in the definition of malfunction], this definition incorporates analogous phrases . . . . Thus using the definition of malfunction as a guide, a system breakdown would constitute something sudden and unforeseen . . . . Accordingly, it is found that a system breakdown requires there to be an occurrence which is unforseen, sudden and unavoidable.

The same logic that went into the ALJ's decision applies here; the exemption was intended for infrequent and unpredictable events, thus, "upset" is analogous to malfunction.

Therefore, the malfunction/upset exemption under NSPS Subpart J applies only to extraordinary, infrequent, and not reasonably preventable upsets. Additionally, the malfunction/upset cannot be the result of poor maintenance or careless operations. Once you determine the cause of a malfunction/upset, you should work to correct the root cause in order to prevent it from occurring again. Each time that is done, malfunctions/upsets should become less frequent.

Process upset gases exempted under NSPS Subpart J are still required to comply with the good air pollution control practices as required under §60.11(d).

> At all times, including periods of start-up, shut-down, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions . . . .

How NSPS Subpart J Applies to the 26 Specific Gas Streams

(Unless stated otherwise, it is assumed that all of the following gas streams are generated "at" the refinery and are combusted. The general concepts identified on page 2 of this letter should be incorporated into EPA's responses when those concepts address the position(s) presented by Koch for a particular gas stream.)

A. Commercial Grade Natural Gas

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, natural gas is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, natural gas meets the definition of fuel gas.

Note: Commercial grade natural gas purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. EPA has previously determined that an NSPS affected gas combustion device is not required to have an installed SO_2 or H_2S CEM if that device has been confirmed to not burn refinery fuel gas, in any mixture and at any time (e.g., To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system). See the December 4, 1991, memorandum from John B. Rasnic. (Enclosure 2)

B. Hydrogen Plant PSA Purge Gas

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

The combustion of Hydrogen Plant PSA Purge gas in the #2 Hydrogen Plant process heater is subject to NSPS Subpart J.

1) Hydrogen Plant PSA Purge Gas meets the definition of fuel gas.

2) The Hydrogen purge gas is burned in the #2 Hydrogen Plant process heater. The #2 Hydrogen Plant process heater meets the definition of FGCD.

3) The #2 Hydrogen Plant process heater is an "affected" FGCD.

C. Commercial Grade Propane (LPG)

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, propane gas is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, propane gas meets the definition of fuel gas.

Note: Commercial grade propane gas purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system.

D. Commercial Grade Hydrogen

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, hydrogen is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, hydrogen meets the definition of fuel gas.

Commercial grade hydrogen purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system.

E. Delayed Coker Blowdown

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's position:

Any coker blowdown gas generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.

1) Vapor from the delayed coker blowdown process meets the definition of fuel gas.

Coker blowdown vapor is generated as a normal part of operations, and not the result of a process upset or malfunction. Nor is it exempt because it is generated during a "shutdown" since the coking process has not shutdown. Rather, the stream to the cokers is merely shifted from one coking drum to another to maintain continuous operation of the coker unit.

2) The hydrocarbon vapors from the blowdown process are directed to your flare gas recovery system. When the refinery flare gas recovery system's capacity is exceeded, the excess gas flared.

3) As described earlier, the refinery flares are affected FGCDs.

F. Rail Loading Rack Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable because the thermal oxidizer is not a "FGCD" subject to Subpart J, and vapors routed to the thermal oxidizer are low in sulfur and are not a "fuel gas" generated by a refinery process.

EPA's response:

Vapor from loading rack operations is subject to NSPS Subpart J if it is combusted in an affected FGCD.

1) Vapors from loading racks located at the refinery meet the definition of fuel gas.

2) Although the oxidizer may be added as a control device under the refinery MACT, it still meets the definition of FGCD under NSPS Subpart J and is subject to NSPS Subpart J. The refinery MACT (40 CFR Part 63 Subpart CC) is designed to limit the

release of hazardous air pollutants (HAPs) and not SO_x from petroleum refineries. Combustion of those HAPs is not the only control option available for compliance with the refinery MACT. Other compliance alternatives under the refinery MACT that do not involve combustion will not trigger the NSPS Subpart J requirements.

G. Soil Vapor Extraction Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable to this stream because vapors recovered from soil remediation are not a "fuel gas", and the thermal oxidizer is not a "FGCD".

EPA's response:

Extracted soil vapor is subject to NSPS Subpart J if it is combusted in an affected FGCD.

1) Vapors extracted from the soil within the refinery meet the definition of fuel gas.

2) The thermal oxidizer is a FGCD since it combusts a fuel gas.

H. Wastewater Treatment Plant Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable because vapors from the wastewater treatment plant are not a "fuel gas", and the thermal oxidizer is not a "FGCD".

EPA's response:

Vapor from the refinery's WWTP is subject to NSPS Subpart J if it is combusted in an affected FGCD.

1) The refinery is operating a wastewater treatment plant (WWTP) at the refinery. The vapors collected from the WWTP meet the definition of fuel gas. Other regulations (i.e., NSPS QQQ) that may cover vapors from the WWTP do not specifically exempt the WWTP vapors from applicability under NSPS Subpart J.

2) Although a thermal oxidizer may be a control device for other regulations (i.e., NSPS QQQ), it meets the definition of FGCD for NSPS Subpart J.

Note: Your claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream is not correct. In approving the SIP order, the gas stream was not characterized as being combusted in an NSPS Subpart J applicable fuel gas combustion device, and EPA was not asked to make a determination of the applicability of NSPS Subpart J to any gas streams or affected fuel gas combustion devices. It merely represents EPA's approval of the State's requirements. Additionally, EPA included language in Amendment Three to the Findings and Order by Stipulation in paragraphs D and H indicating that the order does not relieve Koch of the obligation to comply with all applicable laws and regulations, and that those requirements may be more stringent. The relevant pages of Amendment Three are included as Enclosure 3.

I. Merox Off-Gas (34-H-3 Thermal Oxidizer)

Koch's Position:

NSPS Subpart J is inapplicable to this stream because the thermal oxidizer was constructed prior to June 11, 1973, and has not been modified or reconstructed.

EPA's response:

Any fuel gas combusted in the 34-H-3 thermal oxidizer is not subject to NSPS Subpart J §60.104(a)(1) as long as the thermal oxidizer is not modified or reconstructed.

1) Merox caustic regenerator vent gas, vapors from spent caustic storage tanks, sour water flash drums, and fresh amine storage tanks meet the definition of fuel gas.

2) The 34-H-3 thermal oxidizer meets the definition of FGCD.

3) Based on your statement that the 34-H-3 thermal oxidizer was constructed before June 11, 1973, it is not an "affected" FGCD unless it has since been modified or reconstructed.

J. Caustic Neutralizer Off-Gas

Koch's Position:

NSPS Subpart J is inapplicable to the stream because the CO boiler was constructed prior to June 11, 1973 and has not been modified or reconstructed.

EPA's response:

Any gas combusted in the CO boiler is not subject to NSPS Subpart J §60.104(a)(1) as long as the CO boiler is not modified or reconstructed.

1) The off-gas from the spent caustic neutralizers meets the definition of fuel gas.

2) The spent caustic off-gas is routed to the CO boiler. The CO boiler meets the definition of FGCD.

3) Based on your statement that the CO boiler was constructed before June 11, 1973, and has not been modified or reconstructed, it is not an "affected" FGCD.

K. Reformer Catalyst Regeneration Streams

Koch's Position:

NSPS Subpart J is inapplicable because these streams are inherently low in sulfur, and they fall under the Subpart J exemption for process upset gas.

EPA's response:

Any regeneration gas generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J. Additionally, lock hopper gas that is not directed to the refinery flare gas recovery system but is directed to a refinery heater is subject to NSPS Subpart J if the refinery heater is an affected FGCD.

1) Reformer catalyst regeneration gas streams meet the definition of fuel gas.

Gas produced during the routine switching of reformer reactors, as described by Koch, does not meet the process upset gas definition because the gas is generated as a normal part of operations. Nor is it exempt because it is generated during a "shutdown" since the reformer process has not shutdown. Rather, operations merely shift from one reactor to another so that spent catalyst may be regenerated while the reformer unit continues operation.

2) Reformer catalyst regeneration gas produced during the switching process is directed to your flare gas recovery system or, for final lock hopper depressurization, to a refinery heater. When the refinery flare gas recovery system's capacity is exceeded, the excess gas flared.

3) As described earlier, the refinery flares are affected FGCDs.

L. Vacuum Unit Off-Gas

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

According to your description, equipment leaks may allow air to enter the process creating a potential for the formation of combustible mixtures. Under normal operation, vacuum gases are routed to the fuel gas system. The only time vacuum unit off-gas potentially may be combusted in a fuel gas combustion device is when there has been a process upset as defined under NSPS Subpart J §60.101(e).

EPA's response:

Vacuum unit off-gas that meets the definition of process upset gas is subject to NSPS Subpart A §60.11(d).

1) Vacuum unit off-gas meets the definition of fuel gas.

2) Any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction is a process upset gas.

3) Vacuum unit off-gas generated during periods of a malfunction of the vacuum distillation column meets the definition of process upset gas.

Additionally, in our August 10, 1999, meeting, we discussed the effect of shut-downs of Koch's low pressure off-gas recovery compressor and flare gas recovery compressor. Koch has a compressor system designed to recover discharges (off-gas) from the vacuum generating equipment. The recovered off-gas is normally routed to the refinery fuel gas recovery system for H_2S removal. In the event of an off-gas recovery compressor shut-down, the off-gas is routed to the refinery flare gas recovery system and is not sent to the flare. Only when both compressors malfunction would the gas be routed to the flare. If both compressors are down at the same time due to malfunctions as defined under NSPS Subpart A §60.2, then the vacuum unit off-gas would meet the exemption under NSPS Subpart J §104(a)(1) for other emergency malfunctions. Off-gases exempted from the emission requirements under NSPS Subpart J §60.104(a)(1) are still subject to NSPS Subpart A §60.11(d).

M. Slop Oil Flash Drum

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

Any vapor from the slop oil process which is generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.

1) In general, vapors generated by the slop oil process at Koch meet the definition of fuel gas. Sending off-specification products to the slop oil system does not qualify as a process upset.

2) When the refinery's flare gas recovery's system is exceeded, excess gas is sent to the refinery's flares. Process upsets/malfunctions are not the only reasons that Koch's flare gas recovery system's capacity may be exceeded. The refinery's flare gas recovery system may be exceeded as a result of normal operations (e.g., delayed coker blowdown).

3) As described earlier, the refinery flares are affected FGCDs.

N. Alkylation Unit Acid Neutralization Pit Off-Gas

Koch's Position:

NSPS Subpart J is inapplicable to this stream because the sulfuric acid alkylation units is not a "FGCD", and this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

If the off-gas from the alkylation unit acid neutralization is not combusted, NSPS Subpart J is not applicable. Only gases generated and combusted at the refinery (including purchased gas that is mixed with fuel gas) meet the definition of fuel gas.

O. Flare Pilot and Purge

Koch's Position:

NSPS Subpart J is inapplicable because pilot and purge gas is not a "fuel gas", and this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

As identified in your letter, EPA issued a determination (March 22, 1977) regarding refinery pilot lights. We reaffirm our earlier position that NSPS Subpart J is inapplicable to refinery pilot lights. Since a pilot light ensures that a combustion device will operate properly, the pilot light, by itself, is not the combustion device.

P. Miscellaneous Process Streams Routed to Flare Gas Recovery System

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

Any vapors from the refinery's miscellaneous process streams generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.

1) Vapors from miscellaneous process streams meet the definition of fuel gas because they are not specifically exempted from the definition of fuel gas.

2) When the refinery's flare gas recovery system is exceeded, excess gas is sent to the refinery's flares. Process upsets/malfunctions are not the only reasons that Koch's flare gas recovery system's capacity may be exceeded. The refinery's flare gas recovery system may be exceeded as a result of normal operations.

3) As described earlier, the refinery flares are affected FGCDs.

Q. Butane Storage Tank 517 Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable because this stream is not generated by a Refinery process, it is inherently low in sulfur, and it is subject to the Subpart J exemption for process upsets. To date, the thermal oxidizer has never been used.

EPA's response:

Butane vapors generated as a result of a refrigerator system malfunction are not subject to NSPS Subpart J control requirements, but are subject to NSPS Subpart A §60.11(d).

1) Butane vapors meet the definition of fuel gas.

2) If butane vapors are formed as a result of refrigeration system malfunction, the vapors are routed to tank 517 thermal oxidizer.

3) NSPS Subpart J §61.104(a)(1) exempts the combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunction.

R. FCC Catalyst Regenerator Off-Gas

Koch's Position:

NSPS Subpart J is inapplicable because this stream is subject to the express exemption for catalytic cracking unit catalyst regenerators.

EPA's response:

FCC catalyst regenerator off-gas does not meet the definition of fuel gas and, therefore, is exempt from NSPS Subpart J §60.104(a)(1).

S. MEA and MDEA Regenerator Off-Gas

Koch's Position:

NSPS Subpart J fuel gas requirements are inapplicable because this stream falls under the exemption for facilities that are part of the sulfur production process.

EPA's response:

Sending these streams to the sulfur recovery unit (SRU) does not subject them to the NSPS Subpart J standard for the combustion of a fuel gas in a FGCD.

1) MEA and MDEA regenerator off-gas streams meet the definition of fuel gas.

2) Because these recycled streams are sent to the front of the SRU, and the SRU is a facility in which gases are combusted to produce sulfur or sulfuric acid, these streams are not being combusted in a FGCD.

T. Sour Water Tank Purge Gas

Koch's Position:

This stream falls under the Subpart J exemption for sulfur production facilities and has previously been determined by USEPA to be not subject to NSPS Subpart J fuel gas requirements.

EPA's response:

If the standby incinerator was constructed or modified after June 11, 1973, it is an affected FGCD and the combustion of sour water tank purge gas is subject to NSPS Subpart J.

1) Sour water tank purge gas meets the definition of fuel gas.

2) Sour water tanks store process water from various refinery process units. These tanks are not part of the SRU since they are not part of the unit that recovers sulfur from H_2S by a vapor-phase catalytic reaction of SO_2 and H_2S.

3) At Koch's facility, the sour water tank purge gas is sent to directly to a SRU standby incinerator (affected FGCD) for thermal oxidation without going through the SRU.

Note: Again, you claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream. For the reasons stated in our response to stream H, your belief is not correct.

U. Sour Water Stripper Overhead Gas

Koch's Position:

NSPS Subpart J fuel gas requirements are inapplicable because this stream is part of the sulfur production process and falls under the Subpart J exemption for process upset gas.

EPA's response:

Introducing these streams into the SRU does not subject them to NSPS Subpart J requirements applicable to the combustion of a fuel gas in a FGCD.

1) Sour water stripper overhead gas meets the definition of fuel gas.

2) Sour water strippers are not part of the SRU since they are not part of the unit that recovers sulfur from H_2S by a vapor-phase catalytic reaction of SO_2 and H_2S.

3) Koch sends the sour water stripper overhead gas to the SRU. The SRU is not a FGCD because it is a facility in which gases are combusted to produce sulfur or sulfuric acid.

Note: Koch indicates that this gas may be routed to a FGCD (bypassing the SRU) during periods of start-up, shut-down or malfunction of the SRU. It maintains that such combustion is not subject to Subpart J's sulfur oxide standard because these gases are exempt process upset gases.

Exemptions from rules of general applicability are to be construed narrowly. Nonetheless, EPA recognizes that there are certain limited circumstances under which normal processes may be bypassed because upset conditions exist in some upstream process unit (e.g., if upstream gas quality will cause a malfunction in a downstream unit, the gas is diverted to a flare instead).

It is the refinery's burden to demonstrate that a malfunction has occurred each time a downstream unit is bypassed (or otherwise demonstrate that its actions are exempt from regulation). EPA notes that a malfunction must be infrequent, not reasonably preventable and not attributable to poor maintenance or careless operation. For example, a "malfunction" caused by the same or similar conditions as had occurred previously will lose its exempt character and be subject to all applicable standards and requirements.

Periods of routine or periodic maintenance to downstream units are not malfunctions at either the upstream or the downstream unit. Gases generated in the upstream units are not then process upset gases, their combustion is subject fully to applicable NSPS Subpart J standards and the bypassing (without proper controls) of a downstream unit that is undergoing routine or periodic maintenance would not be permitted.

If the capacity of the SRU is exceeded due to process upset gases, such gases may be flared (but only to the extent attributable to such upset gas). Such instances are also subject to §60.11(d). See discussion above.

V. Ammonia Acid Gas Flare

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas. The acid gas flare is used only for ammonia acid gas that cannot be processed in the SRU due to start-up, shut-down or malfunction.

EPA's response:

Process upset gases are those gases generated by a refinery process unit during periods of start-up, shut-down, upset or malfunction. Such gases are subject to 60.11(d). See discussion above.

1) Ammonia acid gas meets the definition of fuel gas.

2) Combustion of a fuel gas in a flare constructed or modified after June 11, 1973, is subject to Subpart J standards for sulfur oxides, but combustion of process upset gases is exempt from those standards.

Note: Exemptions from rules of general applicability are to be construed narrowly. Nonetheless, EPA recognizes that there are certain limited circumstances under which normal processes may be bypassed because upset conditions exist in some upstream process unit (e.g., if upstream gas quality will cause a malfunction in a downstream unit, the gas is diverted to a flare instead).

It is the refinery's burden to demonstrate that a malfunction has occurred each time a downstream unit is bypassed (or otherwise demonstrate that its actions are exempt from regulation). EPA notes that a malfunction must be infrequent, not reasonably preventable and not attributable to poor maintenance or careless operation. For example, a "malfunction" caused by the same or similar conditions as had occurred previously will lose its exempt character and be subject to all applicable standards and requirements.

Periods of routine or periodic maintenance to downstream units are not malfunctions at either the upstream or the downstream unit. Gases generated in upstream units are not then process upset gases, their combustion is subject fully to applicable NSPS Subpart J standards and the bypassing of a downstream unit that is undergoing routine or periodic maintenance would not be permitted.

Based on information EPA has, numerous episodes of combustion of ammonia acid gas in a flare subject to NSPS Subpart J suggests that there are operation and maintenance problems with those refinery units generating and/or processing that gas.

W. Sulfur Degassing Off-Gas

Koch's Position:

This stream falls under the Subpart J exemption for sulfur production facilities and has previously been determined by USEPA to be not subject to Subpart J fuel gas requirements.

EPA's response:

The sulfur degassing off-gas is generated within the SRU, it is subject to the requirements of NSPS Subpart J §60.104(a)(2) and is exempt from §60.104(a)(1). Please note that some other sulfur pit degasification processes would not be considered as integral parts of a Claus sulfur recovery plant, as defined, and consequently, their exhaust gases could be subject to §60.104(a)(1).

It is our understanding that Koch uses the Shell sulfur degasification process. This process involves a vapor phase reaction that converts much of the dissolved H2S into elemental sulfur within the stripping column of the sulfur pit. For purposes of the regulation, this conversion process is equivalent to the Claus process.

It appears, from your May 14, 1999, Generic Tail Gas Treatment Unit (TGTU) Flow Chart, that the sulfur degassing off-gas is generated within the sulfur pit of each SRU and then routed to the emergency bypass incinerator to be combusted. It is combusted along with sour water tank off-gas, fuel gas and any tail gas from the SRU that bypassed the TGTU. That combustion results in an exhaust that is a combination of gases, some subject to §60.104(a)(1) and others to §60.104(a)(2). Accordingly, each stream going to the emergency bypass incinerator must be monitored separately, or the more stringent of the two limits applies (in this case, the FGCD limit). Streams subject to the same standards may be combined and only the combined stream need then be monitored.

Note: Again, you claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream. For the reasons stated in our response to stream H, your belief is not correct.

X. SRU TGTU Process Heater

Koch's Position:

NSPS Subpart J fuel gas requirements are inapplicable because this stream falls under the exemption for facilities in which gases are combusted to produce sulfur.

EPA's response:

NSPS Subpart J §60.104(a)(2) prohibits the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing excess amounts of SO_2. According to your diagrams, the exhaust from the heater/reactor goes into a liquid-gas H_2S recovery system. The recovered H_2S is then recycled back to the feed line of the SRU. Since the SO_2 is converted into H_2S and is not discharged into the atmosphere, NSPS Subpart J requirements are not applicable to the direct-fired heater on the reducing gas reactor within the TGTU.

Although we agree that this direct fired heater is not subject to NSPS Subpart J §60.104(a)(1) [as discussed above], we do not agree with Koch's interpretation of the heater being exempt because it is part of the sulfur recovery plant. Koch argues that the exemption for sulfur recovery plants applies to this heater. It does not. The heater and reducing gas generator are not in the SRU; the H_2S stream that they generate is desired for improving the efficiency of the SRU, but is not essential for the operation of the SRU; and the recycled H_2S stream would be "fuel gas" if combusted anywhere other than in the SRU or a sulfuric acid plant at the refinery (the two combustion devices exempted from being "FGCDs").

Y. SRU TGTU Incinerator

Koch's Position:

This unit is subject to, and complies with Subpart J requirements for sulfur plants.

EPA's response:

Based on your May 14, 1999, Generic Tail Gas Treatment Unit Flow Chart, Koch's TGTUs meet the definition of "reduction control systems". Each TGTU has attached to it an incinerator. Koch is burning refinery fuel gas and gas from the tail gas absorber in the TGTU incinerator. The exhaust from Koch's TGTU incinerators is a combination of exhausts from two different types of NSPS affected facilities (i.e., an SRU and an FGCD). Therefore, the TGTU incinerator is subject to both the H_2S limit for the fuel gas (§60.104(a)(1)) and the SO_2 limit for the exhaust from a reduction control system followed by incineration (§60.104(a)(2)(i)). The more stringent of the two limits applies (in this case, the FGCD limit) unless compliance can be determined independently for each requirement. Koch monitors the refinery fuel gas for H_2S prior to combustion and monitors the SO_2 levels in the exhaust from the TGTU incinerator. Since compliance for each requirement can be determined separately, Koch does not have to maintain the TGTU incinerator's combined emissions below the FGCD SO_2 emission level, but the SO2 level (adjusted for the combustion of the fuel gas) must meet the limits under §60.104(a)(2)(i). This determination has already been established by EPA in an April 7, 1992 letter. (Enclosure 4)

Z. Propane Flare at Koch Pipeline Company Pipeline Terminal

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

Based on the description provided, EPA understands that the only time any vapors are generated and combusted at this terminal is during periods of shut-down or malfunction. As such, and if a part of the refinery, these gases are process upset gases excluded from Subpart J, but would still be subject to §60.11(d).

EPA also understands that this pipeline terminal is a separate source and is different from the refinery, and the only physical connection to the refinery is via a product pipeline. Since it does not appear to be part of the refinery, these vapors would not be a fuel gas because they are not generated at a refinery.

In your July 9, 1999, Supplemental Submittal, you requested that EPA Headquarters act on your proposed Alternative Monitoring Plan (AMP) and proposed Flare Gas Recovery Performance Policy at the same time as issuing this applicability determination. You state that if EPA does not act on those requests at the same time, you will assume that your requests would ultimately be denied. In our August 10, 1999, meeting, we made it clear that we are willing to work with you on those two requests, but they do not affect the applicability of the regulation. We are confident that we can resolve the issues relating to those two requests, and that your requests will be approved in some form, but it will take time to work out the remaining details. Therefore, we have decided not to delay our response to your original letter from August 14, 1998, while we continue to work together on the AMP and flaring policy.

This determination has been coordinated with EPA's Office of Regulatory Enforcement, the Emission Standards Division of the Office of Air Quality Planning and Standards, the Office of General Counsel, and Several of EPA's Regional offices. If you have any questions, please contact Tom Ripp of my staff at (202) 564-7003.

Sincerely,

S/ KEN GIGLIELLO for

John B. Rasnic, Director
Manufacturing, Energy and Transportation Division
Office of Compliance

cc: Jim Jackson, ORE
Diane McConkey, OGC
Jim Durham, OAQPS
Annette Lang, DOJ
Patrick Foley, Region III
Patric McCoy, Region V
Jonathan York, Region VI
Bill Peterson, Region VII
Lee Hanley, Region VIII
Paul Boys, Region X
Glenna Emanuel, OC

ALTERNATIVE MONITORING PLAN
for NSPS Subpart J Refinery Fuel Gas

Conditions for Approval of the Alternative Monitoring Plan for Miscellaneous Refinery Fuel Gas Streams

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, for approval of an alternative methodology:

- Conduct H_2S testing 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.

Data Range and Variability Calculation and Acceptance Criteria

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 H2S, 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 or 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 from the feed gas to protect the unit's catalyst from 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.