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

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	
v.	)	No. 4:13-cv-2009
SHELL OIL COMPANY, DEER PARK REFINING LIMITED PARTNERSHIP, and SHELL CHEMICAL LP,	)	
Defendants.	)	

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CONSENT DECREE

WHEREAS Plaintiff the United States of America ("United States"), on behalf of the United States Environmental Protection Agency ("EPA"), has filed a complaint against Defendants Shell Oil Company ("Shell Oil"), Deer Park Refining Limited Partnership ("Deer Park Refining"), and Shell Chemical LP ("Shell Chemical") (collectively "SDP"), concurrently with the lodging of this Consent Decree, for alleged environmental violations at Shell Oil's and Deer Park Refining's petroleum refinery ("SDP Refinery") and at Shell Chemical's chemical plant ("SDP Chemical Plant") (collectively "Covered Facilities"), both located in Deer Park, Texas;

WHEREAS, on information and belief, the United States alleges that SDP has violated and/or continues to violate, at the Covered Facilities, one or more of the following statutory and regulatory provisions:

a. The Prevention of Significant Deterioration ("PSD") requirements found in 42 U.S.C. § 7475 and 40 C.F.R. §§ 52.21(a)(2)(iii) and 52.21(j)–52.21(r)(5);

b. The Non-Attainment New Source Review ("NNSR") requirements found in 42 U.S.C. §§ 7502(c)(5), 7503(a)–(c) and 40 C.F.R. Part 51, Appendix S, Part IV, Conditions 1–4;

c. The federally enforceable Minor New Source Review ("Minor NSR") requirements adopted and implemented by the Relevant States in their State Implementation Plans ("SIPs") pursuant to 42 U.S.C. § 7410(a)(2)(C) and 40 C.F.R. §§ 51.160–51.164;

d. The New Source Performance Standards ("NSPS") promulgated at 40 C.F.R. Part 60, Subparts A, J, VV, VVa, GGG, and GGGa, pursuant to Section 111 of the CAA, 42 U.S.C. § 7411;

e. The National Emission Standards for Hazardous Air Pollutants ("NESHAPs") promulgated at 40 C.F.R. Part 61, Subparts A and FF and 40 C.F.R. Part 63, Subparts A, G, CC, FF, and UUU, pursuant to Section 112 of the CAA, 42 U.S.C. § 7412;

f. The requirements of Title V of the CAA found at 42 U.S.C. §§ 7661a(a), 7661b(c), 7661c(a); and 40 C.F.R. §§ 70.1(b), 70.5(a) and (b), 70.6(a) and (c), and 70.7(b);

g. The portions of the Title V permits for the Covered Facilities that adopt, incorporate, or implement the provisions cited in a–e and h–i;

h. The federally enforceable Texas SIP provisions that incorporate, adopt, and/or implement the federal requirements listed in a–b and d–f; and

i. Additional, federally enforceable Texas SIP regulations.

WHEREAS SDP denies that it has violated and/or continues to violate the foregoing statutory and regulatory requirements and denies any liability to the United States arising out of the transactions or occurrences alleged in the Complaint;

WHEREAS SDP previously agreed, under a prior Consent Decree, to comply with 40 C.F.R. Part 60, Subpart J, at certain Flares at the SDP Refinery and has installed, in compliance with that requirement and the requirements of this Decree, a Flare Gas Recovery System ("FGRS") at an estimated total cost of approximately $90 million;

WHEREAS, pursuant to this Decree, SDP has agreed to install a FGRS at the SDP Chemical Plant and to install other equipment to reroute, recover, and minimize Waste Gas flows at both the SDP Refinery and SDP Chemical Plant at an estimated total cost of approximately $90 million;

WHEREAS, for purposes of complying with rules in the State of Texas for limiting emissions of highly reactive Volatile Organic Compounds, SDP, prior to the commencement of negotiations in this matter, installed Vent Gas flow meters and gas chromatographs on Flares designated in this Consent Decree as "Regular-Use" Flares, and, in addition, from 2008 through the Date of Lodging of this Consent Decree, spent more than $9.5 million to improve combustion efficiency and reduce emissions from Flares, and projects that it will spend another $.5 million on these efforts;

WHEREAS SDP estimates that the mitigation projects required pursuant to Section VII of this Decree will cost up to $60 million;

WHEREAS SDP estimates that the Supplemental Environmental Projects required pursuant to Section VIII of this Decree will cost approximately $1.2 million;

WHEREAS, between 2008 and full implementation of this Decree, EPA estimates that emissions from the twelve flares covered by this Consent Decree ("Covered Flares") will be reduced by approximately the following amounts (in "tons per year" or "TPY"):

Pollutant	2008–through implementation
Volatile Organic Compounds ("VOCs")	1,838 TPY
Carbon Dioxide Equivalents ("CO_2e")	261,033 TPY
Hazardous Air Pollutants ("HAPs")	264 TPY
Sulfur Dioxide ("SO_2")	2,412 TPY

WHEREAS, between 2008 and full implementation of this Consent Decree, emissions of hydrogen sulfide ("H_2S") and carbon monoxide ("CO") from the Covered Flares also will be reduced;

WHEREAS EPA estimates that emissions of VOCs will be reduced by approximately 300 TPY when the mitigation projects required in Section VII of this Consent Decree are fully implemented;

WHEREAS SDP intends to convert the flare known as the A&S Flare, which is located at SDP's Chemical Plant, into a Temporary-Use Flare (as that term is defined in this Consent Decree) and to redirect all gases from it to a flare known as the HIPA Flare, also located at SDP's Chemical Plant;

WHEREAS SDP has demonstrated that even after the redirection of the gas flow from the A&S Flare to the HIPA Flare, the HIPA Flare will primarily serve intermittent loading operations and the gas directed to the HIPA Flare will contain high levels of inerts relative to volatile organic compounds, thus making a mass limit of volatile organic compounds from the HIPA Flare an appropriate emissions limit;

WHEREAS SDP has demonstrated that the A&S Flare (after conversion) and the Flares known as the South Property Flare and the CCU Flare will be Temporary-Use Flares;

WHEREAS, prior to the Date of Lodging of this Consent Decree, SDP represented that it completed a project to eliminate a connection between the Girbotol Flare (located at the SDP Refinery) and the A&S and HIPA Flares (located SDP Chemical Plant), and, pursuant to Subsection V.J of this Consent Decree, SDP has agreed to undertake other actions to discover and eliminate all connections from the SDP Refinery to the SDP Chemical Plant Covered Flares that potentially allow Fuel Gas flow;

WHEREAS, by entering into this Consent Decree, SDP has indicated that it is committed to continuing to proactively reduce emissions from its Flares;

WHEREAS this Consent Decree is intended to represent a comprehensive resolution of the claims alleged in the Complaint and the claims resolved through Section XIV (Effect of Settlement) and to ensure that when the compliance measures required by this Decree have been fully implemented, each Covered Flare will be operated and maintained to prevent a recurrence of the violations alleged in the Complaint and the violations resolved through Section XIV (Effect of Settlement);

WHEREAS the United States anticipates that the specific and comprehensive compliance measures set forth in this Consent Decree, which are subject to a reasonable timetable for implementation, will result in the cessation of the violations alleged in the Complaint and the violations resolved through Section XIV (Effect of Settlement);

WHEREAS, the United States and SDP (the "Parties") recognize, and this Court by entering this Consent Decree finds, that this Consent Decree has been negotiated by the Parties in good faith and will avoid litigation between the Parties, and that this Consent Decree is fair, reasonable, and in the public interest;

NOW, THEREFORE, before the taking of any testimony, without the adjudication or admission of any issue of fact or law except as provided in Section I, and with the consent of the Parties, IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action pursuant to 28 U.S.C. §§ 1331, 1345, and 1355; Sections 113(b) and 167 of the CAA, 42 U.S.C. §§ 7413(b) and 7477; and over the Parties. Venue lies in this District 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), because SDP resides and is located in this judicial district and the violations alleged in the Complaint are alleged to have occurred in this judicial district. For purposes of this Decree, or any action to enforce this Decree, SDP consents to this Court's jurisdiction over this Decree, over any action to enforce this Decree, and over SDP. SDP also consents to venue in this judicial district.

2. For purposes of this Consent Decree, SDP does not contest that the Complaint states claims upon which relief may be granted.

3. Notice of the commencement of this action has been given to Texas, under Sections 113(a)(1) and 113(b) of the CAA, 42 U.S.C. §§ 7413(a)(1) and (b).

II. APPLICABILITY

4. The obligations of this Consent Decree apply to and are binding upon the United States and upon SDP and any successors, assigns, and other entities or persons otherwise bound by law.

5. SDP shall give written notice of, and shall provide a copy of, the Consent Decree to any successors in interest at least sixty (60) days prior to the transfer of ownership or operation of any portion of the Covered Facilities. SDP shall notify the United States in accordance with the notice provisions in Section XVI (Notice) of any successor in interest at least thirty days prior to any such transfer.

6. If SDP intends to request that the United States agree to a transferee's assumption of any obligations of the Consent Decree, SDP 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 the Covered Facilities upon the transferee's written agreement to execute a modification to the Consent Decree that shall make the terms and conditions of the Consent Decree applicable to the transferee.

7. As soon as possible prior to the transfer: (i) SDP shall notify the United States of the proposed transfer and of the specific Consent Decree provisions that SDP proposes the transferee assume; (ii) SDP shall certify that the transferee is contractually bound to assume the obligations and liabilities of this Consent Decree; and (iii) the transferee shall submit to the United States a certification that the transferee has the financial and technical ability to assume the obligations and liabilities of this Consent Decree and a certification that the transferee is contractually bound to assume the obligations and liabilities of this Consent Decree.

8. After the submission to the United States of the notice and certification required by the previous Paragraph, either: (i) the United States, shall notify SDP that the United States does not agree to modify the Consent Decree to make the transferee responsible for complying with the terms and conditions of the Consent Decree; or (ii) the United States, SDP, and the transferee shall file with the Court a joint motion requesting the Court approve a modification substituting the transferee for SDP as the Defendants responsible for complying with the terms and conditions of the Consent Decree.

9. If SDP does not secure the agreement of the United States to a joint motion within a reasonable period of time, then SDP and the transferee may file, without the agreement of the United States, a motion requesting the Court to approve a modification substituting the transferee for SDP as the Defendant responsible for complying with some or all of the terms and conditions of the Consent Decree. The United States may file an opposition to the motion. The motion to modify shall be granted unless SDP and the transferee: (i) fail to show that the transferee has the financial and technical ability to assume the obligations and liabilities of the Consent Decree; (ii) fail to show that the modification language effectively transfers the obligations and liabilities to the transferee; or (iii) the Court finds other good cause for denying the motion.

10. Except as provided in Paragraphs 5–9 and Section XI (Force Majeure), SDP shall be 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. SDP shall provide a copy of all applicable portions of this Consent Decree to all officers and employees whose duties might reasonably include compliance with any provision of this Decree. No later than the execution of any contract with a consulting or contracting firm that is retained to perform work required by this Consent Decree,

SDP shall provide a copy of the applicable provisions of this Consent Decree to each such consulting or contracting firm. SDP shall condition any such contract upon performance of the work in conformity with the applicable terms of this Consent Decree. No later than thirty (30) days after the Date of Lodging of the Consent Decree, SDP also shall provide a copy of the applicable provisions of this Consent Decree to each consulting or contracting firm that SDP already has retained to perform the work required by this Consent Decree. Copies of the applicable provisions of the Consent Decree do not need to be supplied to firms who are retained to supply materials or equipment to satisfy requirements of this Consent Decree.

11. In any action to enforce this Consent Decree, SDP shall not raise as a defense the failure by any of its officers, directors, employees, agents, or contractors to take any actions necessary to comply with the provisions of this Consent Decree.

III. DEFINITIONS

12. Terms used in this Consent Decree that are defined in the CAA or in federal and state regulations promulgated pursuant to the CAA, shall have the meaning assigned to them in the CAA, or such regulations, unless otherwise provided in this Decree. Whenever the terms set forth below are used in this Consent Decree, the following definitions shall apply:

a. "Ambient Air" or "air" shall mean that portion of the atmosphere, external to buildings, to which persons have access.

b. "Automatic Control System" or "ACS" shall mean a system that utilizes programming logic to automate the operation of the instrumentation and systems required in Paragraphs 18–23 of this Decree so as to produce the operational results required in Paragraphs 53, 56–59.

c. "Available for Operation" shall mean, with respect to a Compressor within a Flare Gas Recovery System, that the Compressor is capable of commencing the recovery of Potentially Recoverable Gas as soon as practicable but not more than one hour after the Need for the Compressor to Operate arises; the period of time, not to exceed one hour, allowed by this definition for the startup of a Compressor shall be included in the amount of time that a compressor is Available for Operation.

d. "Barrels per day" or "bpd" shall mean barrels per calendar day.

e. "Baseload Waste Gas Flow Rate" shall mean, for a particular Regular-Use Covered Flare, the daily average flow rate, in scfd, to the Flare, excluding all flows during periods of Startup, Shutdown, and Malfunction. The flow rate data period that shall be used to determine Baseload Waste Gas Flow Rate is set forth in Subparagraph 30.b.ii.

f. "BTU/scf" shall mean British Thermal Unit per standard cubic foot.

g. "Calendar Quarter" shall mean a three-month period ending on March 31, June 30, September 30, or December 31.

h. "Capable of Receiving Sweep, Supplemental, and/or Waste Gas" shall mean, for a Flare, that the flow of Sweep, Supplemental, and/or Waste Gas is/are not prevented from being directed to the Flare by means of closed valves and/or blinds.

i. "Center Steam" or "S_{cen}" shall mean steam piped into the center of a Flare stack or center of the lower part of the Flare tip where it mixes directly with Vent Gas without entraining air. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix 1.1 to this Consent Decree.

j. "Center Steam Volumetric Flow Rate" or "$Q_{s\text{-}cen}$" shall mean the volumetric flow rate of Center Steam supplied to a Flare, in scfm, as either measured (if applicable) or estimated using best engineering judgment, on a 5-minute block average.

k. "Center Steam Mass Flow Rate" or "$\dot{m}_{s\text{-}cen}$" shall mean the mass flow rate of Center Steam supplied to a Flare, in pounds per hour, as either measured (if applicable) or estimated using best engineering judgment, on a 5-minute block average using Equation 2 in Appendix 1.2.

l. "Combustion Efficiency" or "*CE*" shall mean a Flare's efficiency in converting the organic carbon compounds found in Vent Gas to carbon dioxide. Combustion Efficiency shall be determined as set forth in Equation 1 in Appendix 1.2.

m. "Combustion Efficiency Multipliers" or "*CE* Multipliers" shall mean empirically derived factors that are used as multipliers of the Net Heating Value of the Vent Gas at its Lower Flammability Limit to ensure an acceptable Combustion Efficiency. The CE Multipliers are set forth in Table 2 of Appendix 1.3 of this Consent Decree.

n. "Combustion Zone" shall mean the area of the Flare flame where the combustion of Combustion Zone Gas occurs.

o. "Combustion Zone Gas" shall mean the mixture of all gases and steam found after the Flare tip. This gas includes all Vent Gas, all Pilot Gas, and all Total Steam.

p. "Compressor" shall mean, with respect to a Flare Gas Recovery System, a mechanical device designed and installed to recover gas from a flare header. Types of Flare Gas Recovery System compressors include reciprocating compressors, centrifugal compressors, liquid ring compressors and liquid jet ejectors.

q. "Consent Decree" or "Decree" shall mean this Consent Decree, including any and all appendices attached hereto.

r. "Covered Facilities" shall mean the SDP Chemical Plant and the SDP Refinery.

s. "Covered Flare" shall mean each of the following Flares:

At SDP Chemical Plant	At SDP Refinery
A&S	CCU
HIPA	Coker
Olefins II	East Property
Olefins III	Ethylene (aka Girbotol)
Olefins Ground	North Property
	South Property
	West Property

t. "Date of Lodging of this Consent Decree" or "Date of Lodging" or "DOL" shall mean the date that this Consent Decree is filed for lodging, pending solicitation of public comment, with the Clerk of the Court for the United States District Court for the Southern District of Texas.

u. "Date of Entry of this Consent Decree" or "Date of Entry" or "DOE" shall mean the Effective Date of this Consent Decree.

v. "Discontinuous Wake Dominated Flow" shall mean gas flow exiting a Flare tip that is identified visually by:

(i) The presence of a flame that is: (1) immediately adjacent to the exterior of the Flare tip body; and (2) below the exit plane of the Flare tip; and

(ii) A discontinuous flame, such that pockets of flame are detached from the portion of the flame that is immediately adjacent to the exterior of the Flare tip body. Representations of Discontinuous Wake Dominated Flow are set forth in Appendix 1.12.

w. "Duplicate Spare Compressor" shall mean, with respect to a Flare Gas Recovery System, an installed compressor, designed to be identical or functionally equivalent to the other compressor(s) of the FGRS. In order to qualify as a "Duplicate Spare Compressor," the compressor must be functionally interchangeable with the other FGRS compressor(s) such that the Operating Design Capacity of the FGRS is Available for Operation while any one compressor of the FGRS is out of service. The capacity of a Duplicate Spare Compressor depends upon the number of compressors installed to meet the Operating Design Capacity of the FGRS. For example, if one compressor is installed to provide an Operating Design Capacity of 270 kscfh, the Duplicate Spare Compressor shall have a capacity of 270 kscfh; if, instead, three, 90 kscfh compressors are installed, the Duplicate Spare Compressor shall have a capacity of 90 kscfh.

x. "Effective Date" shall have the definition set forth in Section XVII (Effective Date) of this Consent Decree.

y. "Elevated Flare" shall mean a Flare that supports combustion at a tip that is situated at the upper end of a vertical conveyance (*e.g.*, pipe, duct); the combustion zone is elevated in order to separate the heat generated by combustion from people, equipment, or structures at grade level.

z. "EPA" shall mean the United States Environmental Protection Agency and any of its successor departments or agencies.

aa. "Exit Velocity" shall mean the velocity ("*v*"), in feet per second, of the Vent Gas and Center Steam as they exit the flare tip. Exit Velocity shall be calculated by adding together the Vent Gas Volumetric Flow Rate and the Center Steam Volumetric Flow Rate, based on standard conditions, and dividing by the Unobstructed Cross Sectional Area of the Flare Tip.

bb. "External Utility Loss" shall mean a loss in the supply of electrical power or other third-party utility to a Covered Facility that is caused by events occurring outside the boundaries of a Covered Facility, excluding utility losses due to an interruptible utility service agreement.

cc. "First Updated Waste Gas Minimization Plan" or "First Updated WGMP" shall mean the document submitted pursuant to Paragraph 31 as the first update to the Initial WGMP.

dd. "Flare" shall mean a combustion device that uses an uncontrolled volume of Ambient Air to burn gases.

ee. "Flare Gas Recovery System" or "FGRS" shall mean a system of one or more compressors, piping, and associated water seal, rupture disk, or similar device used to divert gas from a Flare and direct the gas to a fuel gas system, to a combustion device other than the Flare, or to a product, co-product, by-product, or raw material recovery system.

ff. "Fuel Gas" shall have the definition set forth in 40 C.F.R. § 60.101a.

gg. "Ground Flare" shall mean a Flare or array of Flare tips that supports combustion at or near grade level and uses some form of shielding or barrier to separate the heat generated by combustion from people, equipment, and structures at grade level. Ground Flares include Flares that are partially enclosed.

hh. "Initial Waste Gas Minimization Plan" or "Initial WGMP" shall mean the document submitted pursuant to Paragraph 30.

ii. "In Operation" or "Being In Operation" or "Operating," with respect to a Flare, shall mean any and all times that any gas (*e.g.*, Waste, Vent, Purge, Pilot,) is or may be vented to a Flare. A Flare that is In Operation is Capable of Receiving Sweep, Supplemental, and/or Waste Gas unless all Sweep, Supplemental, and Waste Gas flow is prevented by means of closed valves and/or blinds.

jj. "KSCFH" or "kscfh" shall mean thousand standard cubic feet per hour.

kk. "Lower Flammability Limit" or "*LFL*" shall mean the lowest volumetric concentration of a combustible gas in air that, at a given temperature and pressure, will still combust.

ll. "Lower Flammability Limit of Vent Gas" or "LFL_{vg}" shall mean the weighted average of the LFLs of each of the individual compounds in Vent Gas, weighted by their volume fraction in the Vent Gas. LFL_{vg} is represented by and shall be calculated according to Equation 1 in Appendix 1.3 of this Consent Decree.

mm. "Lower Heating Value" or "*LHV*" shall mean the theoretical total quantity of heat liberated by the complete combustion of a unit volume or weight of a fuel initially at 25 degrees Centigrade and 760 mmHg, assuming that the produced water is vaporized and all combustion products remain at, or are returned to, 25 degrees Centigrade; however, the standard for determining the volume corresponding to one mole is 20 degrees Centigrade.

nn. "Lower Steam" shall mean steam piped to an exterior annular ring near the lower part of a Flare tip, which entrains Ambient Air which flows through tubes to the Flare tip, and ultimately exits the tubes at the top of the Flare tip. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix 1.1 to this Consent Decree.

oo. "Malfunction" shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions. In any action under this Consent Decree involving this definition, SDP shall have the burden of proving a Malfunction and, in interpreting this definition, the ten requirements for a "malfunction" set forth in Section II ("*Affirmative Defenses for Malfunctions*") of EPA's Policy on Excess Emissions during Malfunctions, Startup, and Shutdown shall apply. This Policy is attached as Appendix 1.4.

pp. Momentum Flux Ratio" or "*MFR*" shall mean the ratio of the Vent Gas and Center Steam momentum flux to the wind momentum flux, where momentum flux is the momentum per unit area, per unit time. *MFR* characterizes the degree to which the Ambient Air affects the trajectory of the Vent Gas and Center Steam just as it exits the Flare tip. *MFR* is represented by Equation 1 in Appendix 1.5 and shall be calculated in accordance with the equations, conversion factors, *MFR* constants, *MFR* measured variables, and *MFR* calculated variables set forth in Appendix 1.5.

qq. "Need for a Compressor to Operate" shall mean:

i. For a situation in which no Compressor within the FGRS is recovering gas: When a Potentially Recoverable Gas flow rate (determined on a five-minute block average) to the Covered Flare(s) serviced by the Flare Gas Recovery System exists; or

ii. For a situation in which one or more Compressors within the FGRS already are recovering gas: When the Potentially Recoverable Gas flow rate (determined on a five-minute block average) exceeds the capacity of the operating Compressor(s).

rr. "Net Heating Value" shall mean Lower Heating Value.

ss. "Net Heating Value of Combustion Zone Gas" or "NHV_{cz}" shall mean the Lower Heating Value, in BTU/scf, of the Combustion Zone Gas in a Flare. NHV_{cz} is represented by Equation 5.a or 5.b in Appendix 1.3 to this Consent Decree and shall be calculated in accordance with Equations 5–8 of Appendix 1.3.

tt. "Net Heating Value of Combustion Zone Gas Limit" or "$NHV_{cz\text{-}limit}$" shall mean the minimum Net Heating Value that the Combustion Zone Gas must have to ensure an acceptable Combustion Efficiency.

uu. "Net Heating Value of Hydrogen as Adjusted" or "$NHV_{H2\text{-}adj}$" shall mean 1212 BTU/scf. $NHV_{H2\text{-}adj}$ represents an adjustment to hydrogen's actual Net Heating Value for use, consistent with Step 3 of Appendix 1.3, in the calculation of the NHV_{vg}.

vv. "Net Heating Value of Vent Gas" or "NHV_{vg}" shall mean the Lower Heating Value, in BTU/scf, of the Vent Gas directed to a Flare. NHV_{vg} is calculated as set forth in Equation 2 of Appendix 1.3.

ww. "Net Heating Value of Vent Gas at its Lower Flammability Limit" or "$NHV_{vg\text{-}LFL}$" shall mean the Lower Heating Value, in BTU/scf, of the Vent Gas at its LFL. $NHV_{vg\text{-}LFL}$ is represented by and shall be calculated in accordance with Equation 3 of Appendix 1.3 of this Consent Decree.

xx. "Olefins," for purposes of this Consent Decree, shall mean the following compounds:

Ethene (a/k/a ethylene)
Propene (a/k/a propylene)
Acetylene
But-1-ene (a/k/a butene, alpha-butylene)
Z-but-2-ene (a/k/a beta-butylene, cis-butene)
E-but-2-ene (a/k/a beta-butylene, trans-butene)
2-methylpropene (a/k/a iso-butylene, iso-butene)
1,3 butadiene

yy. "Olefins FGRS" shall mean one or more Flare Gas Recovery Systems designed and operated to recover gas that otherwise would be directed to the Olefins Flares.

zz. "Olefins Flares" shall mean each of the following Covered Flares: the Olefins II Flare, Olefins III Flare, and the Olefins Ground Flare.

aaa. “Operating Design Capacity” shall mean, with respect to a Flare Gas Recovery System, the sum of the capacities, in kscfh, of the installed flare gas recovery Compressors, excluding the capacity of the one installed Duplicate Spare Compressor.

bbb. “Pilot Gas” shall mean all gas introduced through the pilot tip(s) of a Flare to maintain a flame.

ccc. “Portable Flare” shall mean a Flare that is not permanently installed that receives Waste Gas that has been redirected to it from a Covered Flare for periods that are anticipated to be 504 hours or less on a rolling 1095-day period.

ddd. “Potentially Recoverable Gas” shall mean the Sweep Gas, Supplemental Gas, and/or Waste Gas (including hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, and/or water) directed to a Covered Flare’s or group of Covered Flares’ FGRS. Hydrogen produced by the Pressure Swing Absorption (“PSA”) units at the Covered Facilities and introduced between a Covered Flare’s water seal and a Covered Flare’s tip is not Potentially Recoverable Gas.

eee. “Prevention Measure” shall mean an instrument, device, piece of equipment, system, process change, physical change to process equipment, procedure, or program to minimize or eliminate flaring.

fff. “Purge Gas” shall mean the minimum amount of gas introduced between a Flare header’s water seal and the Flare tip to prevent oxygen infiltration (backflow) into the Flare tip. For a Flare with no water seal, the function of Purge Gas is performed by Sweep Gas, and therefore, by definition, such a Flare has no Purge Gas.

ggg. “Regular-Use Flare” shall mean any flare that is not a Temporary-Use or Portable Flare.

hhh. "Regular-Use Covered Flare" shall mean each of the following Covered Flares:

At SDP Chemical Plant	At SDP Refinery
HIPA	Coker
Olefins II	East Property
Olefins III	Ethylene (aka Girbotol)
Olefins Ground	North Property
	West Property

iii. "Reportable Flaring Incident" shall mean, for each of the following time periods, when any one of the following quantities is flared within a 24-hour period at the Covered Facilities:

From the submission of the Initial WGMP until the submission of First Updated WGMP	From the submission of the First Updated WGMP through all times thereafter
≥ 500 lb SO_2 (Refinery Covered Flares Only)	≥ 500,000 scf Waste Gas (All Covered Flares) ≥ 500 lb SO_2 (Refinery Covered Flares Only)

Events that have the same root cause(s) that last more than 24 hours shall be considered a single incident. For purposes of calculating whether the triggering level of SO_2 emissions has been met, when flaring occurs at more than one Covered Flare, the quantity of SO_2 from all Covered Flares involved shall be added together unless the root cause(s) of the flaring at the respective Covered Flares is(are) not related to each other. For purposes of calculating whether the triggering level of Waste Gas flow has been met, the following flows may be excluded: (i) the pro-rated Baseload Waste Gas Flow Rate (pro-rated on the basis of the duration of the Reportable Flaring Incident); and (ii) if SDP has instrumentation capable of calculating the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) in the Waste Gas, the contribution of all measured flows of any of these elements/compounds. When flaring occurs at more than one Covered Flare, the volume of non-excluded Waste Gas flow at all Covered Flares involved shall be added together unless the root cause(s) of the flaring at the respective Covered Flares is (are) not related to each other.

jjj. "SCFD" or "scfd" shall mean standard cubic feet per day.

kkk. "SCFH" or "scfh" shall mean standard cubic feet per hour.

lll. "SCFM" or "scfm" shall mean standard cubic feet per minute.

mmm. "SDP" shall mean Shell Oil Company, Deer Park Refining Limited Partnership, and Shell Chemical LP.

nnn. "SDP Chemical Plant" shall mean the chemical plant owned and operated by Shell Chemical LP located at 5900 Highway 225 East, Deer Park, TX 77536.

ooo. "SDP Chemical Plant Covered Flare" shall mean each of the following Covered Flares:

A&S
HIPA
Olefins II
Olefins III
Olefins Ground

ppp. "SDP Refinery" shall mean petroleum refinery owned by Deer Park Refining Limited Partnership and operated by Shell Oil Company and located at 5900 Highway 225 East, Deer Park, TX 77536.

qqq. "SDP Refinery Covered Flare" shall mean each of the following Covered Flares:

CCU
Coker
East Property
Ethylene (aka Girbotol)
North Property
South Property
West Property

rrr. "Shell's PRI Consent Decree" shall mean the Petroleum Refinery Initiative Consent Decree, as amended and revised, entered in an action styled United States, et al. v. Deer Park Refining Limited Partnership, CA No. H-01-0978 (S.D. Texas).

sss. "Shutdown" shall mean the cessation of operation for any purpose.

ttt. "Smoke Emissions" shall have the definition set forth in Section 3.5 of Method 22 of 40 C.F.R. Part 60, Appendix A. Smoke Emissions may be documented either by a person certified pursuant to Method 22 or by a video camera.

uuu. "Standard Conditions" shall mean a temperature of 68 degrees Fahrenheit and a pressure of 1 atmosphere. Unless otherwise expressly set forth in this Consent Decree or an Appendix, Standard Conditions shall apply.

vvv. "Startup" shall mean the setting in operation for any purpose.

www. "Steam-Assisted Flare" shall mean a Flare that utilizes steam piped to a Flare tip to assist in combustion.

xxx. "Supplemental Gas" shall mean all gas introduced to a Flare to comply with: *(1)* the net heating value requirements of 40 C.F.R. § 60.18(b), 40 C.F.R. § 63.11(b), and/or Paragraph 56 of this Consent Decree; and/or *(2)* the requirements of Paragraphs 57 and/or 58.

yyy. "S/VG_{mass}" or "Total-Steam-Mass-Flow-Rate-to-Vent-Gas-Mass-Flow-Rate Ratio" shall mean the ratio of the Total Steam Mass Flow Rate to the Vent Gas Mass Flow Rate.

zzz. "Sweep Gas" shall mean:

i. For a Flare with a Water Seal: The minimum amount of gas introduced into a Flare header in order to: *(a)* prevent oxygen buildup, corrosion, and/or freezing in the Flare header; and *(b)* maintain a safe flow of gas through the Flare header, including a higher flow during hot taps. Sweep Gas in these Flares is introduced prior to and is intended to be recovered by the Flare Gas Recovery System; and

ii. For a Flare without a Water Seal: The minimum amount of gas introduced into a Flare header in order to: *(a)* prevent oxygen buildup, corrosion, and/or freezing in the Flare header; *(b)* maintain a safe flow of gas through the Flare header, including a higher flow during hot taps; and *(c)* prevent oxygen infiltration (backflow) into the Flare tip.

aaaa. "Temporary-Use Flare" shall mean a permanently installed Flare that receives Waste Gas that has been redirected to it from another flare for periods that are anticipated to be 504 hours or less on a rolling 1095-day average period.

bbbb. "Temporary-Use Covered Flare" shall mean each of the following Covered Flares: A&S, South Property, and CCU.

cccc. "Total Capacity" shall mean, with respect to a Flare Gas Recovery System, the sum of the capacities, in kscfh, of the installed flare gas recovery Compressors, including the capacity of the one installed Duplicate Spare Compressor.

dddd. "Total Steam" or "*S*" shall mean the total of all steam that intentionally is introduced into a Steam-Assisted Flare to assist in combustion. Total Steam includes, but is not limited to, Lower Steam, Center Steam, and Upper Steam.

eeee. "Total Steam Mass Flow Rate" or "$\dot{m}_s$" shall mean the mass flow rate of Total Steam supplied to a Flare, in pounds per hour as calculated on a 5-minute block average. Total Steam Mass Flow Rate shall be calculated as set forth in Equation 3 of Appendix 1.2.

ffff. "Total-Steam-Mass-Flow-Rate-to-Vent-Gas-Mass-Flow-Rate Ratio" or "S/VG_{mass}" shall mean the ratio of the Total Steam Mass Flow Rate to the Vent Gas Mass Flow Rate.

gggg. "Unobstructed Cross Sectional Area of the Flare Tip" or "$A_{tip\text{-}unob}$" shall mean the open, unobstructed area of a Flare tip through which Vent Gas and Center Steam pass. Diagrams of four common flare types are set forth in Appendix 1.6 together with the equations for calculating the $A_{tip\text{-}unob}$ of these four types.

hhhh. "Upper Steam," sometimes called Ring Steam, shall mean steam piped to nozzles located on the exterior perimeter of the upper end of a Flare tip. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix 1.1 to this Consent Decree.

iiii. "Velocity of the Wind" or "Wind Speed" or "v_{wind}" shall mean the velocity of the Ambient Air, in ft/s on a five-minute block average, measured at the Meteorological Station required pursuant to Paragraph 23 of this Consent Decree.

jjjj. "Vent Gas" shall mean the mixture of all gases found just prior to the Flare tip. This gas includes all Waste Gas, Sweep Gas, Purge Gas, and Supplemental Gas, but does not include Pilot Gas, Total Steam, or Assist Air.

kkkk. "Vent Gas Volumetric Flow Rate" or "Q_{vg}" shall mean the volumetric flow rate of Vent Gas directed to a Covered Flare, in wet scfm, on a 5-minute block average basis.

llll. "Vent Gas Mass Flow Rate" or "$\dot{m}_{vg}$" shall mean the mass flow rate of Vent Gas directed to a Covered Flare, in pounds per hour on a 5-minute block average. Vent Gas Mass Flow Rate shall be calculated as set forth in Equation 4 of Appendix 1.2.

mmmm. “Vent Gas Molecular Weight” or “MW_{vg}” shall mean the Molecular Weight, in pounds per pound-mole, of the Vent Gas, on a 5-minute block average.

nnnn. “Visible Emissions” shall mean five minutes or more of Smoke Emissions during any two consecutive hours. For purposes of this Consent Decree, Visible Emissions may be determined by a person certified pursuant to Method 22 or documented by a video camera.

oooo. “VOC” or “Volatile Organic Compounds” shall have the definition set forth in 40 C.F.R. § 51.100(s).

pppp. “VOC Vent Gas Concentration” shall mean the volumetric concentration of VOCs in the Vent Gas and shall be calculated as set forth in Equation 15 of Appendix 1.3.

qqqq. “Waste Gas” shall mean the mixture of all gases from facility operations that is directed to a flare for the purpose of disposing of the gas. “Waste Gas” does not include gas introduced to a flare exclusively to make it operate safely and as intended; therefore, “Waste Gas” does not include Pilot Gas, Total Steam, Assist Air, or the minimum amount of Sweep Gas and Purge Gas that is necessary to perform the functions of Sweep Gas and Purge Gas. “Waste Gas” also does not include the minimum amount of gas introduced to a flare to comply with regulatory and/or enforceable permit requirements and/or the requirements of Paragraphs 56, 57, or 58; therefore, “Waste Gas” does not include Supplemental Gas. Depending upon the instrumentation that monitors Waste Gas, certain compounds (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, and/or water (steam)) that are directed to a Flare for the purpose of disposing of these compounds may be excluded from calculations relating to Waste Gas flow. In Section V of this Consent Decree, the circumstances in which such exclusions are permitted are specifically identified. Appendix 1.7 to this Consent Decree depicts the meaning of “Waste Gas,” together with its relation to other gases associated with Flares.

IV. CIVIL PENALTY

13. By no later than 30 days after the Effective Date of this Consent Decree, SDP shall pay the sum of Two Million, Six-Hundred Thousand Dollars ($2,600,000) as a civil penalty. SDP shall pay the civil penalty by FedWire Electronic Funds Transfer ("EFT") to the U.S. Department of Justice in accordance with written instructions to be provided to SDP, following lodging of the Consent Decree, by the Financial Litigation Unit of the U.S. Attorney's Office for the Southern District of Texas, 1000 Louisiana St., Suite 2300, Houston, TX 77002. At the time of payment, SDP shall send a copy of the EFT authorization form, the EFT transaction record, and a transmittal letter: (i) to the United States in the manner set forth in Section XVI of this Decree (Notices); (ii) by email to acctsreceivable.CINWD@epa.gov; and (iii) by mail to:

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

The transmittal letter shall state that the payment is for the civil penalty owed pursuant to the Consent Decree in United States v. Shell Oil Company, et al., and shall reference the civil action number, USAO File Number 2012VO1637, and DOJ case number 90-5-2-1-09388/1.

14. If any portion of the civil penalty due to the United States is not paid when due, SDP shall pay interest on the amount past due, accruing from the Effective Date through the date of payment, at the rate specified in 28 U.S.C. § 1961. Interest payment under this Paragraph shall be in addition to any stipulated penalty due.

15. SDP shall not deduct any penalties paid under this Decree pursuant to this Section or Section X (Stipulated Penalties) in calculating its federal income tax.

V. COMPLIANCE REQUIREMENTS

A. Instrumentation and Monitoring Systems

16. Flare Data and Monitoring Systems and Protocol Report ("Flare Data and Monitoring Systems and Protocol Report"). For the Covered Flares, by no later than the dates set forth in Column B of Appendix 2.1, SDP shall submit a report, consistent with the requirements in Appendix 1.8, to EPA that includes the following:

a. The information, diagrams, and drawings specified in Paragraphs 1–7 of Appendix 1.8;

b. A detailed description of each instrument and piece of monitoring equipment, including the specific model and manufacturer, that SDP has installed or will install in compliance with Paragraphs 18–23 of this Consent Decree (Paragraphs 8–9 of Appendix 1.8);

c. A narrative description of the monitoring methods and calculations that SDP shall use to comply with the requirements of Paragraphs 56–58 (Paragraph 10 of Appendix 1.8); and

d. The identification of the calibration gases to be used to comply with Subparagraph V.B.1 of Appendix 1.10 (Paragraph 11 of Appendix 1.8).

For any H_2S CEMS required pursuant to 40 C.F.R. Part 60, Subpart J or Subpart Ja, this report shall satisfy the notification requirements of 40 C.F.R. § 60.7(a)(5).

17. Installation and Operation of Monitoring Systems.

a. Regular-Use Covered Flares. By no later than the dates set forth in Column C of Appendix 2.1, for each Regular-Use Covered Flare, SDP shall have completed the installation and commenced the operation of the instrumentation, controls, and monitoring systems set forth in Paragraphs 18–24.

b. Temporary-Use Covered Flares. Prior to directing any Vent Gas to any Temporary-Use Covered Flare, SDP shall have completed the installation of the instrumentation, controls, and monitoring systems set forth in Paragraphs 18–24. SDP shall operate the instrumentation, controls, and monitoring systems for each Temporary-Use Covered Flare at all times that the Flare is Capable of Receiving Sweep, Supplemental, and/or Waste Gas. During periods when a Temporary-Use Covered Flare is not Capable of Receiving Sweep, Supplemental, and/or Waste Gas, the instrumentation, controls, and monitoring systems in Paragraphs 18–24 may be removed and the continuous operation, maintenance, and calibration of those instruments, controls and monitoring systems is not required; provided however, that prior to the Startup of any Temporary-Use Covered Flare, SDP shall take all necessary steps to ensure that the instruments, controls, and monitoring systems are calibrated properly and are capable of continuous operation for the full duration of the use of the Temporary-Use Covered Flare.

18. Vent Gas Flow Monitoring System. This system shall:

a. Continuously measure and calculate the total flow, in scfm and pounds per hour, of all Vent Gas;

b. Continuously analyze pressure and temperature at each point of Vent Gas flow measurement; and

c. Have retractable or removable sensors at each point of Vent Gas flow measurement to ensure that the Vent Gas Flow Monitoring System is maintainable online.

19. Vent Gas Average Molecular Weight Analyzer. This instrument or system shall continuously analyze the average molecular weight of all Vent Gas. This analysis may be performed by an instrument that also serves as part of a Vent Gas Flow Monitoring System.

20. Total Steam Flow Monitoring System. This system shall:

a. Continuously measure and calculate the flow, in scfm and pounds per hour, of the Total Steam to each Covered Flare; and

b. Continuously analyze the pressure and temperature of steam at a representative point of steam flow measurement.

21. Steam Control Equipment. This equipment, including, as necessary, main and trim control valves and piping, shall enable SDP to control steam flow in a manner sufficient to ensure compliance with this Decree.

22. Gas Chromatograph ("GC") or Net Heating Value Analyzer. Each Regular-Use Covered Flare shall be equipped with a GC. Each Temporary-Use Covered Flare shall be equipped with either a GC or a Net Heating Value Analyzer. The GCs and, to the extent used, Net Heating Value Analyzers, shall meet the following requirements:

a. Gas Chromatograph. This instrument shall be capable of speciating the Vent Gas constituents set forth in Appendix 1.9.on a mole percent ("mol/mol%") basis. The sample extraction point of the Gas Chromatograph may be located upstream of the introduction of Supplemental and/or Sweep and/or Purge Gas if the composition and flow rate of any such Supplemental and/or Sweep and/or Purge Gas is a known constant and if this constant then is used in the calculation of the volume percent of all gas constituents of the Vent Gas.

b. Net Heating Value Analyzer. This instrument shall measure the Net Heating Value of the Vent Gas in BTU/scf. The sample extraction point of the Net Heating Value Analyzer may be located upstream of the introduction of Supplemental and/or Sweep and/or Purge Gas if the composition and flow rate of any such Supplemental and/or Sweep and/or Purge Gas is a known constant and if this constant then is used in the calculation of the Net Heating Value of the Vent Gas.

23. Meteorological Station or "Met Station" (one Met Station can to be used for both Covered Facilities; not one for each Covered Facility and not one for each Covered Flare). This station shall include meteorological data instruments capable of measuring wind speed. The station shall be placed at a location where wind is representative of conditions at the Regular-Use Covered Flare with the largest estimated volume of Waste Gas after Waste Gas minimization is complete. The Meteorological Station shall be located as high as reasonably practicable but does not have to be as high as the Regular-Use Covered Flare that its location is based on.

24. Video Camera. This instrument shall record, in digital format, the flame of (including any resulting from Discontinuous Wake Dominated Flow), and any Smoke Emissions from, the Regular-Use Covered Flares.

25. Instrumentation and Monitoring Systems: Optional Equipment for any Covered Flare. At its option, SDP may elect to install (if not already installed) an instrument to continuously measure and calculate flow, in scfm and pounds per hour, of all Pilot Gas to a Covered Flare. SDP may utilize the data generated by this instrument as part of the calculation of the Net Heating Value of the Combustion Zone Gas.

26. Instrumentation and Monitoring Systems: Specifications. The instrumentation and monitoring systems identified in Paragraphs 18–20 and 22–23 shall meet or exceed the specifications set forth in Appendix 1.10.

27. Instrumentation and Monitoring Systems: Recording and Averaging Times. The instrumentation and monitoring systems identified in Paragraphs 18–20 and 22–24 shall be able to produce and record data measurements and calculations for each parameter at the following time intervals.

Instrumentation and Monitoring System	Recording and Averaging Times
Vent Gas Flow; Vent Gas Average Molecular Weight; Total Steam Flow; Pilot Gas Flow (if installed)	Measure continuously and record 5 minute block averages
Gas Chromatograph	Measure no less than once every 15 minutes and record that value
Net Heating Value Analyzer	Measure continuously and record 5 minute block averages
Wind Speed	Measure continuously and record 5 minute block averages
Video Camera	Record at a rate of no less than 4 frames per minute

Nothing in this Paragraph is intended to prohibit SDP from setting up process control logic that uses different averaging times from those in this table provided that the recording and averaging times in this table are available and used for determining compliance with this Consent Decree.

28. Instrumentation and Monitoring Systems: Operation and Maintenance. SDP shall operate each of the instruments and monitoring systems required in Paragraphs 18–20 and 22–24 on a continuous basis when the Covered Flare that the instrument and/or monitoring system is associated with is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas, except for the following periods:

a. Malfunction of an instrument and/or monitoring system;

b. Maintenance following instrument and/or monitoring system Malfunction;

c. Scheduled maintenance of an instrument and/or monitoring system in accordance with the manufacturer's recommended schedule; and/or

d. Quality Assurance/Quality Control activities.

In no event, however, shall the excepted activities in Subparagraph 28.a–28.d for any instrument monitoring a Regular-Use Covered Flare exceed 110 hours in any calendar quarter nor shall the excepted activities in Subparagraph 28.a–28.d for any instrument monitoring a Temporary-Use Covered Flare exceed 5% of the time that the Temporary-Use Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas during an uninterrupted time period. The calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VI of Appendix 1.10. If the excepted activities in Subparagraphs 28.a–28.d for any instrument exceed their allowable amount, EPA shall be entitled to seek stipulated penalties as set forth in Subparagraph 93.e or 93.f (as applicable) of this Consent Decree and SDP shall be entitled to assert that the period of instrumentation and monitoring system downtime was justified under the circumstances. Nothing in this Paragraph is intended to prevent SDP from claiming a *force majeure* defense to any period of instrumentation and/or monitoring system downtime. Nothing in this Paragraph supersedes or replaces the monitoring requirements, including operation, maintenance, and quality assurance/quality control requirements of 40 C.F.R. Part 60, Subparts J and Ja at such time as those requirements become applicable pursuant to Paragraph 64. All such requirements shall apply in accordance with the terms set forth in Subparts J and Ja.

B. Determining Whether a Covered Flare that has a Water Seal is Not Receiving Potentially Recoverable Gas Flow

29. For a Covered Flare that has a water seal, if all of the following conditions are met, then the Covered Flare is not receiving Potentially Recoverable Gas flow:

a. For the water seal drum associated with the respective Covered Flare, the pressure difference between the inlet pressure and the outlet pressure is less than the water seal pressure as set by the static head of water between the opening of the dip tube in the drum and the level-setting weir in the drum;

b. For the water seal drum associated with the respective Covered Flare, the water level in the drum is at the level of the weir; and

c. Downstream of the seal drum, there is no flow of Supplemental Gas directed to the Covered Flare.

C. <u>Waste Gas Minimization</u>

30. <u>Initial Waste Gas Minimization Plan ("Initial WGMP")</u>. By no later than the dates set forth in Column D of Appendix 2.1, for each Regular-Use Covered Flare, SDP shall submit to EPA an Initial Waste Gas Minimization Plan that discusses and evaluates flaring Prevention Measures both Facility-wide and on a Flare-specific basis. The Initial WGMP submitted for the HIPA Flare shall include a discussion and evaluation of flaring Prevention Measures that were implemented for gas that was directed to the A&S Flare before that gas was rerouted to the HIPA Flare. The Facility-wide evaluation shall include one evaluation for the SDP Refinery and a separate evaluation for the SDP Chemical Plant; provided however, that interconnections between the two Covered Facilities may be evaluated on a consolidated basis. The Initial WGMP shall include but not be limited to:

a. <u>Updates</u>. SDP shall submit updates, if and as necessary, to the information, diagrams, and drawings provided in the Flare Data and Monitoring Systems and Protocol Report required under Paragraph 16.

b. <u>Waste Gas Characterization and Mapping</u>. SDP shall undertake to characterize the Waste Gas being disposed of at each Regular-Use Covered Flare and determine its source as follows:

i. <u>Volumetric (in scfm) and mass (in pounds) flow rate</u>. SDP shall identify the volumetric flow of Waste Gas, in scfm on a 30-day rolling average, and the mass flow rate, in pounds per hour on a 30-day rolling average, vented to each Regular-Use Covered Flare for the one-year period of time prior to 31 days before the submission of the Initial WGMP. To the extent that, for any particular Regular-Use Covered Flare, SDP has instrumentation capable of measuring and/or calculating the volumetric and mass flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) in the Waste Gas, SDP may break down the volumetric and mass flow as between: (i) All Waste Gas flows excluding hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam); and (ii) hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) flows in the Waste Gas. SDP may use either an engineering evaluation or measurements from monitoring or a combination to determine flow rate. In determining flow rate, flows during all periods (including but not limited to normal operations and periods of Startup, Shutdown, Malfunction, process upsets, relief valve leakages, utility losses due to an interruptible utility service agreement, and emergencies arising from events within the boundaries of the Covered Facilities), except those described in the next sentence, shall be included. Flows that could not be prevented through reasonable planning and are in anticipation of or caused by a natural disaster, act of war or terrorism, or External Utility Loss are the only flows that shall be excluded from the calculation of flow rate. SDP shall specifically describe the date, time, and nature of the event that results in the exclusion of any flows from the calculation.

ii. <u>Baseload Waste Gas Flow Rates</u>. SDP shall utilize flow rate data for the one-year period of time prior to 31 days before the submission of the Initial WGMP to determine the Baseload Waste Gas Flow Rate, in scfd, to each Regular-Use Covered Flare. The Baseload Waste Gas Flow Rate shall not include flows during periods of Startup, Shutdown, and Malfunction.

iii. <u>Identification of Constituent Gases</u>. SDP shall use best efforts to identify the constituent gases within each Regular-Use Covered Flare's Waste Gas and the percentage contribution of each such constituent during baseload conditions. SDP may use either an engineering evaluation or measurements from monitoring or a combination to determine Waste Gas constituents.

iv. <u>Waste Gas Mapping</u>. Using instrumentation, isotopic tracing, and/or engineering calculations, SDP shall identify and estimate the flow from each process unit header (sometimes referred to as a "subheader") to the main header(s) servicing the Regular-Use Covered Flare. Using that information and all other available information, SDP shall complete an identification of each Waste Gas tie-in to the main header(s) and process unit header(s), as applicable, consistent with Appendix 1.11. Temporary connections to the main header(s) of a Regular-Use Covered Flare and/or process unit header(s) are not required to be included in the mapping.

c. Reductions previously realized. SDP shall describe the equipment, processes and procedures installed or implemented since 2008 to reduce flaring. The description shall specify the date of installation or implementation and the amount of reductions realized.

d. Planned reductions. SDP shall describe the equipment, processes, or procedures that SDP plans to install or implement to eliminate or reduce flaring. The description shall specify a schedule for expeditious installation and commencement of operation and a projection of the amount of reductions to be realized. Subsequent to the submission of the WGMP, SDP may revise the installation and operation dates provided that SDP does so in writing to EPA within a reasonable time of determining that such a revision(s) is(are) necessary and provides a reasonable explanation for the revised date(s). In formulating this plan, SDP specifically shall review and evaluate the results of the Waste Gas Mapping required by Subparagraph 30.b.iv.

e. Taking a Covered Flare Permanently Out of Service. SDP shall identify any Covered Flare that it intends to permanently take out of service, including the date for completion of the decommissioning. Taking a Covered Flare "permanently out of service" means physically removing piping in the Flare header or physically isolating the piping with a welded blind so as to eliminate direct piping to the Covered Flare and surrendering any permit to operate such Covered Flare.

f. Prevention Measures. SDP shall describe and evaluate all Prevention Measures, including a schedule for the expeditious implementation and commencement of operation of all Prevention Measures, to address the following:

i. Flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including Startup and Shutdown. The evaluation shall include a review of flaring that has occurred during these activities since January 2009 and shall consider the feasibility of performing these activities without flaring.

ii. Flaring that may reasonably be expected to occur due to issues of gas quantity and quality. The evaluation shall include a general audit of the existing flare gas recovery capacity of each Regular-Use Covered Flare, the storage capacity available for excess Waste Gases, and the scrubbing capacity available for Waste Gases including any limitations associated with scrubbing Waste Gases for use as fuel.

iii. Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall consider the adequacy of existing maintenance schedules and protocols for such equipment. A failure is "recurrent" if it occurs more than twice during any five year period as a result of the same cause.

31. First Updated Waste Gas Minimization Plan. By no later than the dates set forth in Column E of Appendix 2.1, SDP shall submit to EPA a First Updated WGMP which shall update for the 12-month period after the period covered by the Initial Waste Gas Minimization Plan, if and as necessary, the information required in Subparagraphs 30.a–30.f and shall also include the following:

a. Updated Waste Gas Mapping. SDP shall update the Waste Gas mapping as more information becomes available. SDP shall use this updated mapping to plan reductions;

b. Reductions Based on Root Cause Analysis. SDP shall review all of the Root Cause Analysis reports submitted under Paragraph 35 to determine if reductions in addition to the reductions achieved through any required corrective action under Paragraph 36 can be realized; and

c. Revised Schedule. To the extent that SDP proposes to extend any schedule set forth in the Initial WGMP, SDP may do so only with good cause.

32. Subsequent Updates to Waste Gas Minimization Plan.

a. SDP Chemical Plant. In the first semi-annual report required under Section IX of this Decree (Reporting Requirements) that is due no sooner than one year after the submission of the First Updated WGMP, SDP shall submit a Second Updated WGMP for the SDP Chemical Plant. On an annual basis thereafter until termination of the Decree, SDP shall submit an updated WGMP for the SDP Chemical Plant as part of the semi-annual report. Each update shall update, if and as necessary, the information required in Subparagraphs 30.a–30.f, 31.a, and 31.b. To the extent that SDP proposes to extend any schedule set forth in a previous WGMP for the SDP Chemical Plant, SDP may do so only with good cause.

b. SDP Refinery. For the SDP Refinery, in lieu of submitting any updates to the Initial and First Updated WGMP under this Consent Decree, SDP shall comply with the Flare Management Plan requirements of NSPS Subpart Ja, 40 C.F.R. § 60.103a(a)–(b), by no later than November 11, 2015.

33. Waste Gas Minimization Plan: Implementation. By no later than the dates specified in a WGMP, SDP shall implement the actions described therein. If (i) no implementation date and/or (ii) no completion date for actions that do not require ongoing implementation (such as the installation of a piece of a equipment) is (are) set forth in the WGMP, the implementation and/or completion date shall be deemed the date of the submission of the WGMP.

34. Enforceability of WGMPs. The terms of each WGMP (including Initial, First Updated, and Subsequent Updated WGMPs) submitted under this Consent Decree are specifically enforceable.

35. Root Cause Analysis for Reportable Flaring Incident.

a. Internal Reporting and Recordkeeping. Except as provided in Paragraphs 37 and 38.a, commencing on the dates set forth in the definition of "Reportable Flaring Incident" in Section III of this Decree (Definitions), by no later than forty-five days following the end of a Reportable Flaring Incident, SDP shall conduct an investigation into the Root Cause(s) of the Incident and prepare and keep as a record an internal report that shall include, at a minimum, the following:

i. The date and time that the Reportable Flaring Incident started and ended;

ii. The volume of Waste Gas flared and an estimate of the quantity of VOCs and SO_2 that was emitted and the calculations that were used to determine that quantity;

iii. The steps, if any, that SDP took to limit the duration of the Reportable Flaring Incident and quantity of VOC and/or SO_2 emissions associated therewith;

iv. A detailed analysis that sets forth the root cause and all contributing causes of the Reportable Flaring Incident, to the extent determinable;

v. An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of a Reportable Flaring Incident resulting from the same root cause or contributing causes in the future. The analysis shall discuss the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, if an alternative is eliminated based on cost. Possible design and operation and maintenance changes shall be evaluated. If SDP concludes that corrective action(s) is (are) required under Paragraph 36, 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 SDP concludes that corrective action is not required under Paragraph 36, the report shall explain the basis for that conclusion; and

vi. To the extent that investigations of the causes and/or possible corrective actions still are underway 45 days after the Reportable

Flaring Incident, a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Paragraph shall be completed.

b. Submitting Summary of Internal Flaring Incident Reports. In each semi-annual report due under Section IX of this Decree (Reporting Requirements), SDP shall include a summary of the following items for each Reportable Flaring Incident that occurred during the six-month period that the semi-annual report covers:

i. Date;

ii. Duration;

iii. Amount of SO_2 and VOC released;

iv. Root Cause(s);

v. Corrective Action(s) completed;

vi. Corrective Action(s) still outstanding; and

vii. An analysis of any trends identified by SDP in terms of the number of Incidents, the Root Causes, or the types of Corrective Action.

36. Corrective Action Implementation. In response to any Reportable Flaring Incident, SDP 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 contributing causes of that Reportable Flaring Incident.

37. In lieu of preparing a new report under Paragraph 35 and analyzing and implementing corrective action under Paragraph 36 for a Reportable Flaring Incident that has as its root cause the same root cause as a previously reported Reportable Flaring Incident, SDP may cross-reference and utilize the prior report and analysis when preparing the report required by Paragraph 35.

38. Overlapping Requirements.

a. Root Cause Analysis and Corrective Action Requirements under SDP's PRI Consent Decree. To the extent that a Reportable Flaring Incident that is triggered solely by the SO_2 threshold in the definition of "Reportable Flaring Incident" also constitutes an Acid Gas or Hydrocarbon Flaring Incident under Shell's PRI Consent Decree, SDP shall follow the provisions of Shell's PRI Consent Decree, and not the provisions of this Decree, for addressing the incident, for as long as Shell's PRI Consent Decree is in effect.

b. Root Cause Analysis and Corrective Action Provisions of NSPS Subpart Ja. With respect to the Covered Flares at the SDP Refinery, SDP no longer shall be required to comply with the root cause analysis and corrective action provisions in Paragraphs 35–36 of this Consent Decree on and after November 11, 2015. At that time, SDP shall comply with the requirements of NSPS Subpart Ja, 40 C.F.R. § 60.103a(c)–(e).

D. Flare Gas Recovery Systems at the SDP Refinery

39. Flare Gas Recovery Systems at the SDP Refinery: Capacity and Start-Up Dates. By no later than the following dates for the following Regular-Use Covered Flares at the SDP Refinery, SDP shall complete installation and commence operation of the following Flare Gas Recovery Systems at the SDP Refinery:

FGRS ID	Covered Flares	FGRS Operating Design Capacity (kscfh)	Total No. of Compressors (includes one Spare per FGRS)	Capacity of each Compressor (kscfh)	FGRS Total Capacity (kscfh)	Date
CPU	North and West	350	2	350	700	DOE
Coker	Coker	290	6	58	348	DOE
EPF/Girbotol	East Property and Girbotol	500	2	500	1000	DOE

40. Flare Gas Recovery Systems at the SDP Refinery: Operation.

a. General. SDP shall operate each FGRS in a manner to minimize Waste Gas to the respective Covered Flares while ensuring safe refinery operations. SDP also shall operate each FGRS consistent with good engineering and maintenance practices and in accordance with its design and the manufacturer's specifications.

b. Requirements Related to Compressors Being Available for Operation and/or in Operation. By no later than December 31, 2014, SDP shall comply with the following requirements when Potentially Recoverable Gas is being generated:

i. CPU and EPF/Girbotol Flare Gas Recovery Systems. For the CPU and East Property/Girbotol Flare Gas Recovery Systems, SDP shall have one Compressor Available for Operation and/or in operation 98% of the time and two Compressors Available for Operation and/or in operation 90% of the time. Periods of maintenance and subsequent restart on the Compressors within the CPU and/or EPF/Girbotol Flare FGRSs may be included in the amount of time that the Compressors are Available for Operation when determining compliance with the requirement to have two Compressors Available for Operation and/or in operation 90% of the time, provided that these periods shall not exceed 1344 hours per Compressor in a five-year rolling sum period, rolled daily.

ii. Coker Flare Gas Recovery System. For the Coker Flare Gas Recovery System, SDP shall have five Compressors Available for Operation and/or in operation 95% of the time and four

Compressors Available for Operation and/or in operation at all times. The following periods may be included in the amount of time that a Compressor is Available for Operation when determining compliance with the requirement to have four Compressors Available for Operation and/or in operation "at all times":

(1) Periods of maintenance on and subsequent restart of the equipment within the Coker FGRS that is shared by all Compressors (for example, the water seal, the knock-out drum, valves), such that the entire FGRS must be shut down in order to undertake the maintenance; provided however, that these periods shall not exceed 336 hours in a five-year rolling sum period, rolled daily. SDP shall use best efforts to schedule these maintenance activities during a turnaround of the process units venting to the Coker Flare. To the extent it is not practicable to undertake these maintenance activities during a turnaround, SDP shall use best efforts to minimize the generation of Waste Gas during such periods.

(2) Periods in which the four Compressors are shut down (including the subsequent restart) due to operating conditions (such as high temperatures or large quantities of entrained liquid in the Vent Gas) outside the design operating range of the Coker FGRS, including the associated knock-out drum(s), such that the outage is necessary for safety and/or to preserve the mechanical integrity of the Coker FGRS. By no later than 45 days after any such period of outage, SDP shall investigate the root cause and all contributing causes of the outage and shall implement, as expeditiously as practicable, corrective action, if any, to prevent a recurrence of the cause(s). In the reports due under Section IX of this Decree, SDP shall describe each outage that occurred under the conditions identified in this Subparagraph, including the date, duration, cause(s), corrective action, and the status of the implementation of corrective action.

iii. Period to be Used for Computing Percentage of Time. For purposes of calculating compliance with the 90%, the 95%, and the 98% of time that a Compressor or group of Compressors must be Available for Operation and/or in operation, as required by Subparagraphs 40.b.i and 40.b.ii, the period to be used shall be an 8760-hour rolling sum, rolled hourly, using only hours when Potentially Recoverable Gas was generated during all or part of the hour but excluding hours for flows that could not have been prevented through reasonable planning and were in anticipation of or caused by a natural disaster, act of war or terrorism, or External Utility Loss. When no Potentially Recoverable Gas was generated during an entire hour, then that hour shall not be used in computing the 8760-hour rolling sum. The rolling sum shall include only the prior 8760 1-hour periods when Potentially Recoverable Gas was generated during all or part of the hour, provided that the Potentially Recoverable Gas was not generated by flows that could not have been prevented through reasonable planning and were in anticipation of or caused by a natural disaster, act of war or terrorism, or External Utility Loss.

E. Flaring Limitations at the SDP Refinery

41. Limitations on Flaring at the SDP Refinery: Initial Limits.

a. On and after the following dates, SDP shall comply with the following limitations on flaring from all SDP Refinery Covered Flares and Portable Flares (if any):

i. Refinery-Wide 30-day Rolling Average. By no later than December 31, 2017, SDP shall comply with the following Refinery-wide short-term limit: 2,455,944 scfd of Waste Gas on a 30-day rolling average basis, rolled daily.

ii. Refinery-Wide 365-day Rolling Average. By no later than December 31, 2014, SDP shall comply with the following Refinery-wide long-term limit: 1,637,296 scfd of Waste Gas on 365-day rolling average basis, rolled daily.

iii. The rolling average period shall include only the prior 30 or 365 days, as applicable, when any Refinery Covered Flare or Portable Flare was/were In Operation.

Each exceedance of the 30-day rolling average limit or each exceedance of the 365-day rolling average limit shall constitute one day of violation. An exceedance of either or both of the limits shall not prohibit ongoing refinery operations.

b. The limitations set forth in Subparagraph 41.a were calculated using the equations set forth in Subparagraph 43.a.i and ii. Appendix 2.3 sets forth the actual calculation. The "*SDP Ref. Crude Capacity*" was taken from the "Total Operable" atmospheric crude oil distillation capacity, in barrels per calendar day, found in Part 5, Code 401, of the Form EIA-820 that SDP submitted to the Energy Information Agency ("EIA") for the 2012 report year. The value reported was 327,000 barrels per calendar day. A copy of that Form is included in Appendix 2.3. The "*SDP Complexity*" and "*Industry Avg Complexity*" were calculated pursuant to the methodology set forth in Appendix 1.14.

42. Intentionally left blank.

43. Limitations on Flaring at the SDP Refinery: Requesting an Increase in the Limit(s).

a. SDP Request. Once per calendar year commencing no sooner than January 1, 2016, SDP may submit a request to EPA to increase the limitations in flaring set forth in Subparagraphs 41.a and/or 41.b. SDP may request an increase in the limit(s), and EPA will approve such an increase, only if the request is based on post-Lodging changes in crude capacity and/or complexity that are or will be permitted by the State of Texas and only if the changes in crude capacity and/or complexity result in new limit(s) that are higher by at least 20% than the limits set forth in Subparagraphs 41.a and/or 41.b. In any such request, SDP shall propose (a) new limit(s) (hereafter referred to as "New Limit(s) Based on Projections") based upon the following equations:

i. For the Refinery-wide, 30-day rolling average limit:

$$\text{Refinery Flaring} \leq 750{,}000 \text{ scfd} \times \frac{\textit{SDP Ref. Crude Cap.}}{100{,}000 \text{ bpd}} \times \frac{\textit{SDP Complexity}}{\textit{Industry Avg Complexity}}$$

ii. For the Refinery-wide, 365-day rolling average limit:

$$\text{Refinery Flaring} \leq 500{,}000 \text{ scfd} \times \frac{\textit{SDP Ref. Crude Cap.}}{100{,}000 \text{ bpd}} \times \frac{\textit{SDP Complexity}}{\textit{Industry Avg Complexity}}$$

Nothing in this Paragraph or Consent Decree shall be construed to relieve SDP of an obligation to evaluate, under applicable Prevention of Significant Deterioration and Nonattainment New Source Review requirements, any increase in a Refinery-Wide limit on flaring.

b. For purposes of Subparagraphs 43.a.i and 43.a.ii, the following shall apply:

i. The items in italics are variables that will change over time.

ii. The *SDP Ref. Crude Capacity* shall be determined as follows:

(1) If the post-Lodging modification does not affect the crude capacity, the Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, that the Refinery reported under "Total Operable" capacity on Part 5, Code 401, of the Applicable Form EIA-820; the definition of "Applicable Form EIA-820" is found in the "Definitions" section of Appendix 1.14; to the extent that the "Parts" or "Codes" on Form EIA-820 change in the future, the intent of the Parties is that the "Parts" and "Codes" of future forms that correspond most closely to those found on the Form EIA-820 for Report Year 2012 (see Attachment 2 to Appendix 1.14) will be used; or

(2) If the post-Lodging modification does affect crude capacity, the projected, new capacity set forth in the air permit application(s) for the post Lodging modification

iii. *SDP Complexity* shall be calculated in accordance with Equation 1 of Appendix 1.14. SDP shall certify the accuracy of the projected crude capacity and/or process unit capacities used to support the calculations.

iv. The *Industry Average Complexity* shall be calculated in accordance with Equation 2 of Appendix 1.14.

c. EPA Response to Request. EPA shall evaluate any request under Subparagraph 43.a on the basis of consistency with Subparagraphs 43.a.i and 43.a.ii. If EPA does not act on SDP's request within 90 days of submission, SDP may invoke the accelerated dispute resolution provisions of Subsection XII.B of this Decree.

d. The New Limit(s) Based on Projections shall take effect, if ever, beginning on the later of the date that EPA approves the request or a dispute is resolved in SDP's favor or the date(s) specified in the modification permit(s).

e. In the event that SDP amends, modifies or withdraws the air permit application(s) that is/are the basis for the New Limit(s) Based on Projections requested pursuant to Subparagraph 43.a in a manner that affects the limit(s) calculation(s), SDP shall, within 15 days of amending, modifying, or withdrawing its air permit application(s), revise or withdraw its request under Subparagraph 43.a. To the extent that SDP revises, rather than withdraws, its request under Subparagraph 43.a, the 90-day deadline under Subparagraph 43.c for EPA's response to the revised request shall commence upon the date of EPA's receipt of SDP's revised request.

f. Consequences of a Mistake in Projected Capacities.

i. By no later than 30 days after the Startup of the permitted modifications, SDP shall determine whether the projected "*SDP Ref. Crude Capacity*" or the projected capacities for new or modified units that SDP relied upon pursuant to Subparagraphs 43.b.ii and/or b.iii, respectively, were or are different from the actual capacities that SDP has or will report to the EIA or the Oil & Gas Journal after the Startup of the permitted modification. If there are differences, SDP shall re-calculate the flaring limitation(s) using the actual capacities that SDP has or will report to the EIA or the Oil & Gas Journal (hereafter referred to as "New Limit(s) Based on Actuals").

ii. If the New Limit(s) Based on Actuals that SDP calculates under Subparagraph 43.f.i is/are greater than the New Limit(s) Based on

Projections that SDP calculated under Subparagraph 43.a, then no further action shall be required and the New Limit(s) Based on Projections shall remain in effect.

iii. If the New Limit(s) Based on Actuals that SDP calculates under Subparagraph 43.f.i is/are less than the New Limit(s) Based on Projections that SDP calculated under Subparagraph 43.a, then by no later than 30 days after the Startup of the permitted modifications, SDP shall: *(1)* commence complying with the New Limit(s) Based on Actuals; and *(2)* submit the revised, recalculated New Limit(s) Based on Actuals to EPA. After submission to EPA, SDP shall consult with EPA about the New Limit(s) Based on Actuals and secure EPA's approval.

iv. Stipulated Penalties. If Subparagraph 43.f.iii applies, then by no later than 60 days after the Startup of the permitted modifications, the New Limit(s) Based on Actuals identified in the submission to EPA under Subparagraph 43.f.iii*(2)* shall apply and form the basis for determining compliance for purposes of the stipulated penalty provisions of Subparagraphs 93.l and 93.m. If EPA disapproves the New Limit(s) Based on Actuals, the New Limit(s) Based on Actuals shall continue to apply for purposes of stipulated penalties until such time as other limitation(s) either is/are agreed upon between EPA and SDP or a dispute is resolved that sets forth revised limitation(s).

44. Limitations on Flaring at the SDP Refinery: Meaning and Calculation of "Waste Gas" Flow for Purposes of the Limitation on Flaring. For purposes of the meaning and calculation of "Waste Gas" flow in the limitations on flaring in Subparagraphs 41.a.i and 41.a.ii, and any revised limitations on flaring developed pursuant to Paragraph 43, the following shall apply:

a. To the extent that SDP has instrumentation capable of calculating the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) in the Waste Gas, the contribution of all measured flows of any of these elements/compounds may be excluded from the Waste Gas flow rate calculation.

b. Flows during all periods (including but not limited to normal operations and periods of Startup, Shutdown, Malfunction, process upsets, relief valve leakages, utility losses due to an interruptible utility service agreement, and emergencies arising from events within the boundaries of the Refinery), except those expressly described in the next sentence, shall be included. Flows that could not be prevented through reasonable planning and are in anticipation of or caused by a natural disaster, act of war or terrorism, or External Utility Loss may be excluded from the calculation of flow rate.

c. Except for hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) contributions to the flow rate that are excluded by virtue of instrumentation measuring these flows, for any flow that SDP does not include in a computation, SDP shall submit the following information in the semi-annual report due under Paragraph 85 of this Consent Decree: a description of the event that resulted in the exclusion; the date(s) and duration(s) of the flows caused by the event; the estimated VOC and SO_2 emissions during the event; whether flows from the event are anticipated to persist after the notice, and if so, for how long; and the measures taken or to be taken to prevent or minimize the flows, including, for future anticipated flow, the schedule by which those measures will be implemented.

F. Flare Gas Recovery System at the Olefins Flares of the SDP Chemical Plant

45. Olefins FGRS: Capacity and Start-Up Date.

a. By no later than December 31, 2017, SDP shall complete installation and commence operation of one or more Flare Gas Recovery System(s) for the Olefins Flares. Except as provided in Paragraph 46, the Operating Design Capacity of the Olefins FGRS(s) shall be a minimum of 270 kscfh.

b. The design of each Olefins FGRS shall include one installed Duplicate Spare Compressor.

46. Process of Securing a Decrease in the Operating Design Capacity of the Olefins FGRS.

a. SDP Request for an Operating Design Capacity of Less than 270 kscfh. Pursuant to the requirements of Subsection V.C of this Consent Decree ("Waste Gas Minimization"), SDP shall undertake efforts to minimize Waste Gas flow to, *inter alia*, the Olefins Flares. Because of those activities, by no later than SDP's submission of its First Updated WGMP, SDP may submit a request to EPA for approval of a decrease in the 270 kscfh Operating Design Capacity of the Olefins FGRS. In any such request, SDP must:

i. Continue to commit to install (a) Duplicate Spare Compressor(s) consistent with the requirements of Paragraph 45.b; and

ii. Demonstrate that the newly requested Operating Design Capacity and number of compressors of the Olefins FGRS will result in an Estimated Percent Recovery of 80% or more as calculated in accordance with the Paragraph 46.b.

b. Calculation of Estimated Percent Recovery. In undertaking the demonstration required in Subparagraph 46.a.ii, SDP shall use the hourly average Vent Gas flow-adjusted data set ("HFvg-adjusted data set"), as defined below, to calculate the Estimated Percent Recovery in accordance with the methodology specified in Appendix 2.4. In addition, the following shall apply:

i. SDP shall submit, in editable spreadsheet form, the hourly average Vent Gas flow data set for each hour of the year that ends 30 days prior to the date of SDP's request for EPA approval of a decrease in the Operating Design Capacity of the Olefins FGRS ("HFvg-baseline data set").

ii. To account for Vent Gas flow reductions that SDP will secure from specific sources of Vent Gas as a result of identified modifications and/or identified revised operating practices that SDP, in its request for a decrease in the Olefins FGRS Operating Design Capacity, commits to complete between the date of its request and December 31, 2017, SDP shall adjust each hourly average Vent Gas flow rate in the HFvg-baseline data set by subtracting out the contribution to the flow from specific sources of Vent Gas that SDP commits to eliminate, *i.e.*, "Enforceable Reductions." SDP shall also submit an adjusted Hourly Average Vent Gas flow data set ("HFvg-adjusted data set") that represents the HFvg-baseline data set as adjusted by the identified Enforceable Reductions. The HFvg-adjusted data set shall be submitted in editable spreadsheet form and shall include the hourly average Vent Gas flow data set as adjusted for each hour of the year that ends 30 days prior to the request for a decrease in the Olefins FGRS Operating Design Capacity.

iii. SDP shall assume that the amount of time that the proposed size and number of Compressors will be "Available for Operation" will equal the percentages specified in Subparagraph 47.b.

iv. "Enforceable Reductions" shall mean reductions in the Vent Gas Flow that SDP shall secure from specific sources of Vent Gas as a result of identified modifications and/or identified revised operating practices that SDP, in its request for a decrease in the Olefins FGRS Operating Design Capacity, commits to complete between the date of its request and December 31, 2017. To the extent that SDP commenced implementation of any such modifications and/or revised operating practices prior to its request but the resulting Vent Gas Flow reductions were not yet realized and included in the Vent Gas Flow for the full one year period that is 30 days prior to the request, SDP may include them in the Enforceable Reductions. In its request, SDP shall include documentation supporting the scope and expected flow reduction(s) from the modifications and/or revised operating practices and a schedule for the implementation of these activities prior to December 31, 2017.

v. "Vent Gas Flow," for all purposes in the equations used in this Paragraph, shall include flows during all periods (including but not limited to normal operations and periods of Startup, Shutdown, Malfunction, process upsets, relief valve leakages, External Utility Losses due to an interruptible utility service agreement, and emergencies arising from events within the boundaries of the Facilities), except those described in the next sentence. Vent Gas Flows that could not be prevented through reasonable planning and are in anticipation of or caused by a natural disaster, act of war or terrorism, or External Utility Loss are the only flows that shall be excluded from the calculation of flow. In making its request for a smaller Operating Design Capacity for the Olefins FGRS, SDP specifically shall describe the date, time, and nature of any event that results in the exclusion of any Vent Gas Flows from its calculation.

c. EPA Response to Request. EPA shall evaluate any request under Subparagraphs 46.a and b on the basis of its consistency with the requirements of those Subparagraphs. If EPA does not act on SDP's request within 90 days of submission, SDP may invoke the accelerated dispute resolution provisions of Subsection XII.B of this Decree. The new Design Operating Capacity shall take effect, if ever, on the date that EPA approves the request or a dispute is resolved in SDP's favor.

47. Olefins FGRS: Operation.

a. General. After the December 31, 2017 deadline in Paragraph 45.a, SDP shall operate the Olefins FGRS(s) in a manner to minimize Waste Gas to the Olefins Flares while ensuring safe chemical plant operations. SDP also shall operate the Olefins FGRS consistent with good engineering and maintenance practices and in accordance with its design and the manufacturer's specifications.

b. Requirements Related to Compressors Being Available for Operation. By no later than June 30, 2018, SDP shall comply with the following requirements for the Olefins FGRS when Potentially Recoverable Gas is being generated:

i. An Olefins FGRS with two (2) Compressors (one of which is the required Duplicate Spare Compressor) shall have one compressor Available for Operation and/or in operation 98% of the time and two Compressors Available for Operation and/or in operation 90% of the time. If these two Compressors are reciprocating Compressors, periods of maintenance on them and subsequent restart may be included in the amount of time that the Compressors are Available for Operation when determining compliance with the requirement to have two Compressors Available for Operation and/or in operation 90% of the time; provided however, that these periods shall not exceed 1344 hours per Compressor in a five-year rolling sum period, rolled daily.

ii. An Olefins FGRS with more than two (2) Compressors (one of which is the required Duplicate Spare Compressor) where the total number of Compressors is represented by "n," shall have n-1 Compressors Available for Operation and/or in operation 95% of the time and n-2 Compressors Available for Operation and/or in operation at all times. The following periods may be included in the amount of time that a Compressor is Available for Operation when determining compliance with the requirement to have "n-2" Compressors Available for Operation and/or in operation "at all times":

(1) Periods of maintenance on and subsequent restart of the equipment within the Olefins FGRS that is shared by all Compressors (for example, the water seal, the knock-out drum, valves), such that the entire FGRS must be shut down in order to undertake the maintenance; provided however, that these periods shall not exceed 336 hours in a five-year rolling sum period, rolled daily. SDP shall use best efforts to schedule these maintenance activities during a turnaround of the Olefins unit. To the extent it is not practicable to undertake these maintenance activities during an Olefins turnaround, SDP shall use best efforts to minimize the generation of Waste Gas during such periods.

(2) Periods in which the "n-2" Compressors are shut down (including the subsequent restart) due to operating conditions (such as high temperatures or large quantities of entrained liquid in the Vent Gas) outside the design operating range of the Olefins FGRS, including the associated knock-out drum(s), such that the outage is necessary for safety and/or to preserve the mechanical integrity of the Compressors. By no later than 45 days after any such outage, SDP shall investigate the root cause and all contributing causes of the outage and shall implement, as expeditiously as practicable, corrective action, if any, to prevent a recurrence of the cause(s). In the reports due under Section IX of this Decree, SDP shall describe each outage that occurred under the conditions identified in this Subparagraph, including the date, duration, cause(s), corrective action, and the status of the implementation of corrective action.

iii. <u>Period to be Used for Computing Percentage of Time</u>. For purposes of calculating compliance with the 90%, the 95%, and the 98% of time that a Compressor or group of Compressors must be Available for Operation and/or in operation, as required by

Subparagraphs 47.b.i and 47.b.ii, the period to be used shall be an 8760-hour rolling sum, rolled hourly, using only hours when Potentially Recoverable Gas was generated during all or part of the hour but excluding hours for flows that could not have been prevented through reasonable planning and were in anticipation of or caused by a natural disaster, act of war or terrorism, or External Utility Loss. When no Potentially Recoverable Gas was generated during an entire hour, then that hour shall not be used in computing the 8760-hour rolling sum. The rolling sum shall include only the prior 8760 1-hour periods when Potentially Recoverable Gas was generated during all or part of the hour, provided that the Potentially Recoverable Gas was not generated by flows that could not have been prevented through reasonable planning and were in anticipation of or caused by a natural disaster, act of war or terrorism, or External Utility Loss.

G. Limitations on Flaring at the A&S and HIPA Flares of the SDP Chemical Plant

48. Conversion of A&S Flare to a Temporary -Use Flare. By no later than June 30, 2013, SDP will convert the A&S Flare to a Temporary-Use Flare by rerouting flow from the A&S Flare to the HIPA Flare.

49. Limitation on VOC Emissions from the HIPA Flare. By no later than 24 months after the Date of Entry, SDP shall not emit from the HIPA Flare more than 25 tons per year of VOCs in a 365-day rolling sum period, rolled daily. SDP shall utilize the equations set forth in Appendix 2.5 to calculate VOC emissions from the HIPA flare in any given 365-day rolling sum period. After incorporation of the limit into a federally-enforceable permit, nothing in this Consent Decree shall prohibit SDP from seeking an increase in this limit (regardless of the amount of the increase) prior to termination of this Consent Decree if SDP undertakes a LAER analysis through appropriate Texas state permitting authorities in order to secure the increase.

H. Flare Combustion Efficiency

50. General Emission Standards Applicable to Covered Flares. By no later than the dates set forth in Column F of Appendix 2.1, SDP shall comply with the requirements set forth in this Paragraph at all times when the Covered Flare is In Operation.

a. Operation during Emissions Venting. SDP shall operate each Covered Flare at all times when emissions may be vented to it.

b. No Visible Emissions. Except for periods of Startup, Shutdown, and/or Malfunction, SDP shall operate each Covered Flare with no Visible Emissions. Method 22 in 40 C.F.R. Part 60, Appendix A, shall be used to determine compliance with this standard. However, for purposes of this Consent Decree, Visible Emissions may be determined by a person certified pursuant to Method 22 or documented by a video camera.

c. Flame Presence. SDP shall operate each Covered Flare with a flame present at all times. SDP shall monitor the presence of the pilot flame using a thermocouple or any other equivalent device to detect the presence of the pilot flame.

d. Monitoring According to Applicable Provisions. SDP shall comply with all applicable Subparts of 40 C.F.R. Parts 60, 61, or 63 that state how a particular Covered Flare must be monitored.

e. Good Air Pollution Control Practices. At all times, including during periods of Startup, Shutdown, and/or Malfunction, SDP shall implement good air pollution control practices to minimize emissions from each Covered Flare; provided however, that SDP shall not be in violation of this requirement for any practice that this Consent Decree requires SDP to implement after the Date of Lodging for the period between the Date of Lodging and the implementation date or compliance date (whichever is applicable) for the particular practice.

51. Exit Velocity. Beginning no later than the dates set forth in Column C of Appendix 2.1, except for periods of Startup, Shutdown, and/or Malfunction, SDP shall operate each Covered Flare with an Exit Velocity less than 18.3 m/sec (60 ft/sec) on a one-hour block average; provided however, that:

a. If the Covered Flare combusts Vent Gas with a Net Heating Value of greater than 1000 BTU/scf, SDP may operate the Covered Flare with an Exit Velocity equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) on a one-hour block average; and

b. If the Covered Flare has a maximum permitted velocity (Vmax), SDP may operate the Covered Flare with an Exit Velocity less than Vmax provided that it also operates the applicable Flare with an Exit Velocity of less than 122 m/sec (400 ft/sec) on a one-hour block average. V_{max} shall be calculated in accordance with 40 C.F.R. § 60.18(f)(5). The Unobstructed Cross Sectional Area of the Flare Tip shall be calculated consistent with Appendix 1.6.

52. Revisions to 40 C.F.R. §§ 60.18(b)–(f) and/or 63.11(b). To the extent that, from the Date of Lodging of this Consent Decree until its termination, revisions to 40 C.F.R. §§ 60.18(b)–(f) and/or 63.11(b) are final and effective that are inconsistent with any of the requirements in Paragraphs 50.a–d or 51, then SDP shall comply with the final, effective regulations and any requirements in Paragraphs 50.a–d and/or 51 that are not inconsistent with these final, effective regulations. As used in this Paragraph, "inconsistent" mean that compliance with both provisions is not possible.

53. Work Practice Standards for each Covered Flare.

a. Regular-Use Covered Flares. By no later than the dates set forth in Column G of Appendix 2.1, utilizing the instrumentation and controls required to be installed pursuant to Paragraphs 18–24, SDP shall install on each Regular-Use Covered Flare an Automatic Control System that shall:

i. Automate the control of the Supplemental Gas flow rate to the respective Flare; and

ii. Automate the control of the Total Steam Mass Flow Rate to the respective Flare.

For the Regular-Use Covered Flares, SDP shall operate these Automated Control Systems immediately upon installation.

b. Temporary-Use Covered Flares. After the dates set forth in Column G of Appendix 2.1, SDP shall not direct any Sweep, Supplemental, and/or Waste Gas to any Temporary-Use Flare, until an Automatic Control System that conforms to the requirements of Subparagraph 53.a is installed. SDP shall operate the Automated Control System whenever any Sweep, Supplemental, and/or Waste Gas is directed to the Temporary-Use Covered Flare. During those periods after the installation of the ACS when the Temporary-Use Covered Flare is not Capable of Receiving Sweep, Supplemental and/or Waste Gas, the operation of the ACS is not required; provided however, that prior to the Startup of a Temporary-Use Covered Flare, SDP shall take all necessary steps to ensure that the ACS is capable of continuous operation for the full duration of the use of the Temporary-Use Covered Flare.

54. Exception to Work Practice Standards in Subparagraph 53. SDP manually may override the operation of the Automatic Control System(s) required in Subparagraph 53 if the exception in Paragraph 60 applies, and/or during Startup, Shutdown, or Malfunction of a Covered Flare or a process unit that feeds a Covered Flare, and/or to achieve the following:

a. Stop Smoke Emissions that are occurring;

b. Meet the Net Heating Value requirements of Paragraph 56;

c. Prevent extinguishing the Flare;

d. Protect personnel and process safety;

e. Stop Discontinuous Wake Dominated Flow; and/or

f. Stop acoustic disturbances that are occurring.

55. Operation According to Design. By no later than the dates set forth in Column H of Appendix 2.1, SDP shall operate and maintain each Covered Flare in accordance with its design, except if, and only to the extent that, operation and maintenance of the Covered Flare in conformance with its design conflicts with compliance with one or more of the requirements of this Consent Decree

56. Net Heating Value Standards.

a. Net Heating Value of Vent Gas (NHV_{vg}). Beginning on the Date of Lodging and continuing until the earlier of: (i) termination of this Consent Decree; or (ii) the requirements in 40 C.F.R. §§ 60.18(c)(3)(ii) and 63.11(b)(6)(ii) related to the NHV_{vg} are modified, SDP shall operate each Covered Flare, except as provided in Paragraph 60, with an NHV_{vg} of greater than or equal to 300 BTU/scf at all times that the gas being combusted in the Covered Flare is subject to the control requirements of 40 C.F.R. § 60.18(c)(3)(ii) and/or § 63.11(b)(6)(ii).

b. Net Heating Value of Combustion Zone Gas (NHV_{cz}) for Regular-Use Covered Flares, excluding the Olefins Ground Flare. By no later than the dates set forth in Column H of Appendix 2.1, and except as provided in Paragraph 60.a, SDP shall calculate an $NHV_{cz\text{-}limit}$ at each Regular-Use Covered Flare no less frequently than every fifteen minutes. Except as provided in Paragraph 60.a, SDP shall operate each Regular-Use Covered Flare so as to ensure that the Regular-Use Covered Flare's NHV_{cz}, on a three-hour rolling average, rolled every fifteen minutes, is greater than or equal to its $NHV_{cz\text{-}limit}$ on a three-hour rolling average, rolled every fifteen minutes. SDP shall utilize the equations and directives set forth in Appendix 1.3 to meet the requirements of this Subparagraph 56.b.

c. Net Heating Value of Combustion Zone Gas (NHV_{cz}) for the Olefins Ground Flare. By no later than the date set forth in column H of Appendix 2.1, and except as provided in Paragraph 60.a, SDP shall calculate the NHV_{cz} at the Olefins Ground Flare no less frequently than every 15 minutes. Except as provided in Paragraph 60.a, SDP shall operate the Olefins Ground Flare so as to ensure that its NHV_{cz}, on a three-hour rolling average basis, rolled every fifteen minutes, is equal to or greater than 500 BTU/scf, using a Net Heating Value for hydrogen of 1212 BTU/scf. SDP shall utilize Steps 3 and 6 in Appendix 1.3 to calculate NHV_{cz}.

d. Net Heating Value of Combustion Zone Gas (NHV_{cz}) for Temporary-Use Covered Flares. After the dates set forth in Column H of Appendix 2.1, SDP shall not direct any Sweep, Supplemental, and/or Waste Gas to any Temporary-Use Flare unless SDP calculates the NHV_{cz} at such Temporary-Use Flare during its operation, except as provided in Paragraph 60.b. SDP may use either a gas chromatograph or Net Heating Value Analyzer to calculate/measure the Net Heating Value of the Vent Gas. If SDP uses a gas chromatograph to calculate Net Heating Value, SDP shall use a Net Heating Value for hydrogen of 1212 BTU/scf and shall calculate the NHV_{cz} no less frequently than every 15 minutes. If SDP uses a Net Heating Value Analyzer to measure Net Heating Value of the Vent Gas, SDP shall calculate the NHV_{cz} no less frequently than every five minutes. Except as provided in Paragraph 60.b, SDP shall operate each Temporary-Use Covered Flare so as to ensure that its NHV_{cz} is greater than or equal to 355 BTU/scf: (i) on a three-hour rolling average basis, rolled every fifteen minutes if a gas chromatograph is used; (ii) on a one-hour rolling average basis, rolled every five minutes, if a

Net Heating Value Analyzer is used. SDP shall utilize Steps 3 and 6 in Appendix 1.3 to calculate NHV_{cz}.

57. S/VG Standards (Total-Steam-to-Vent-Gas Ratio Standards).

a. Interim Period. Beginning on the Date of Lodging and continuing until the dates set forth in Column H of Appendix 2.1, and except as provided in Subparagraph 57.c and Paragraph 60, SDP shall use best efforts to operate each Covered Flare at less than or equal to an S/VG_{mass} of 3.0 on a one-hour rolling average, rolled every five minutes.

b. After Interim Period. By no later than the dates set forth in Column H of Appendix 2.1, and except as provided in Subparagraph 57.c and Paragraph 60, SDP shall operate each Covered Flare at less than or equal to an S/VG_{mass} of 3.0 on a one-hour rolling average, rolled every five minutes. For each Covered Flare, SDP shall record the S/VG_{mass}.

c. Exceptions. Notwithstanding the requirements of Subparagraphs 57.a and 57.b, SDP is not subject to the emissions standards in those Subparagraphs if the exception in Paragraph 60 applies and/or in order to achieve the following:

i. Stop Smoke Emissions that are occurring;

ii. Meet the Net Heating Value requirements of Paragraph 56;

iii. Prevent extinguishing the Flare; and/or

iv. Protect personnel and process safety.

58. Prohibition on Discontinuous Wake Dominated Flow or Requirement for Minimum Momentum Flux Ratio ("MFR") for Covered Flares.

a. The requirements of this Paragraph have no applicability to Ground Flares; therefore, the Olefins Ground Flare is not subject to this Paragraph. All references to "Covered Flares" in this Paragraph exclude the Olefins Ground Flare.

b. By no later than the dates set forth in Column H of Appendix 2.1, for each Covered Flare, SDP shall comply with either Subparagraph 58.c. or 58.d. In the first semi-annual report due after the applicable compliance date, SDP shall identify which compliance option it selects for each Covered Flare. SDP may select different alternatives for different Covered Flares and may change its election for any given Covered Flare by providing EPA with 30 days prior notice of the change. The notice shall include the reasons SDP is changing its compliance option.

c. Prohibition on Discontinuous Wake Dominated Flow.

i. SDP shall not operate the Covered Flares with Discontinuous Wake Dominated Flow (as defined above and in Appendix 1.12 of the Consent Decree), except for periods not to exceed a total of five minutes during any two consecutive hours. SDP shall add Supplemental Gas as necessary to prevent such instances of Discontinuous Wake Dominated Flow at the Covered Flares.

ii. Prior to the effective date of the prohibition in Subparagraph 58.c.i, for all operators and supervisors with responsibility and/or oversight for the operation of each Covered Flare, SDP shall complete training on the meaning and prevention of Discontinuous Wake Dominated Flow. After this effective date, operators shall monitor the operation of each Covered Flare at intervals appropriate for the weather conditions and service of the Covered Flare in order to comply with the prohibition in Subparagraph 58.c.i.

d. MFR Requirements. MFR shall be calculated in accordance with the equations, conversion factors, MFR constants, MFR measured variables, and MFR calculated variables set forth in Appendix 1.5. SDP shall either:

i. Maintain a minimum MFR of 0.0010 for the Olefins II and Olefins III Flares and a minimum MFR of 0.0030 for all other Covered Flares, each on a 60-minute rolling average, rolled every 5 minutes; or

ii. Propose a Flare-specific minimum MFR. SDP shall submit such a proposal to EPA for approval. In any such proposal, SDP shall demonstrate, using, at a minimum, photographs correlated to MFR, that at the proposed minimum MFR, Discontinuous Wake Dominated Flow will not occur for the Covered Flare that is the subject of the request.

iii. Calculation of MFR "on a 60-minute rolling average, rolled every 5 minutes," when there are more than 5 but less than 12 consecutive 5 minute averages of MFR. During any period of Vent Gas flow to the Covered Flare when there are more than 5 but less than 12 consecutive 5 minute averages of MFR, the MFR "on a 60-minute rolling average, rolled every 5 minutes" shall be calculated using the 5-minute averages that are greater than "0" during the period and for which the exception in Paragraph 58.e does not apply; the 5-minute averages when MFR is "0" because either there is no Vent Gas flow or the exception in Paragraph 58.e applies shall not be used in calculating the 60-minute rolling average, rolled every 5 minutes.

e. Exceptions to the Prohibition on Discontinuous Wake Dominated Flow and MFR Requirements. Notwithstanding Subparagraphs 58.c. and 58.d, SDP shall not be required to add Supplemental Gas, and the requirements in those Subparagraphs are not applicable, at any time that Paragraph 60 applies and/or the wind speed at the Covered Facilities is greater than or equal to 35 mph on a 60-minute rolling average, rolled every 5 minutes.

59. 98% Combustion Efficiency. By no later than the dates set forth in Column H of Appendix 2.1, SDP shall operate each Covered Flare with a minimum of a 98% Combustion Efficiency at all times when Waste Gases are vented to it. To demonstrate continuous

compliance with the 98% Combustion Efficiency, SDP shall operate each Covered Flare in compliance with the applicable requirements in Paragraphs 56–58.

60. Exception for Instrument Downtime.

a. Regular-Use Covered Flares. For Regular-Use Covered Flares, a failure to comply with the work practices or standards in Subparagraphs 53.a, 56.a, 56.b, 56.c, 57.a, 57.b, 58.c, or 58.d shall not constitute a violation of such work practice or standard if the noncompliance results from downtime of instruments or equipment due to the following:

i. Malfunction of an instrument, for an instrument needed to meet the requirement(s);

ii. Maintenance following instrument Malfunction, for an instrument needed to meet the requirement(s);

iii. Scheduled maintenance of an instrument in accordance with the manufacturer's recommended schedule, for an instrument needed to meet the requirement(s); and/or

iv. Quality Assurance/Quality Control activities on an instrument needed to meet the requirement(s).

This exception shall no longer be applicable if the activities in Subparagraphs 60.a.i–60.a.iv exceed 110 hours in any calendar quarter for any instrument. The calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VI of Appendix 1.10.

b. Temporary-Use Covered Flares and Portable Flares. For Temporary-Use Covered Flares and Portable Flares, a failure to comply with the work practices or standards in Subparagraphs 53.b, 56.a, 56.d, 57.a, 57.b, 58.c, or 58.d shall not constitute a violation of such work practice or standard if the noncompliance results from downtime of instruments or equipment due to the activities in Subparagraphs 60.a.i–iv; provided however, that this exception shall no longer be applicable if the activities in Subparagraphs 60.a.i–iv exceed 5% of the time that the Temporary-Use Covered Flare or Portable Flare is In Operation and capable of receiving Waste, Supplemental, and/or Sweep Gas during an uninterrupted time period. The calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VI of Appendix 1.10.

61. Inapplicability of Paragraphs 56–59. The requirements of Paragraphs 56–59 are not applicable to any Covered Flare or Portable Flare when the only gas or gases being vented to the Covered Flare or Portable Flare is/are Pilot Gas and/or Purge Gas.

62. Recordkeeping: Timing and Substance. SDP shall comply with the following recordkeeping requirements:

a. By no later than three months after the dates set forth in Column C of Appendix 2.1, SDP shall calculate and record each of the following parameters:

i. Total Steam Volumetric Flow Rate (in scfm) and Total Steam Mass Flow Rate (in lb/hr) (in accordance with the recording and averaging times required in Paragraph 27)

ii. Vent Gas Volumetric Flow Rate (in scfm) and Vent Gas Mass Flow Rate (in lb/hr) (in accordance with the recording and averaging times required in Paragraph 27)

iii. S/VG_{mass} (in lb steam/lb Vent Gas) (in accordance with the averaging times in Subparagraph 57.b)

iv. NHV_{vg} (in BTU/scf) (on a one-hour block average)

v. NHV_{cz} (in BTU/scf) (in accordance with the averaging times in Subparagraphs 56.b, 56.c, and 56.d)

vi. $NHV_{cz\text{-}limit}$ (in BTU/scf) (in accordance with the averaging times in Subparagraphs 56.b)

b. By no later than six months after the first full calendar quarter starting on or after the dates set forth in Column C of Appendix 2.1, commencing if and when the excepted activities in Subparagraphs 28.a–28.d for any instrument subject to Paragraph 28 exceed 110 hours in any calendar quarter for a Regular-Use Covered Flare, or 5% of the time that a Temporary-Use Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas during an uninterrupted time period, SDP shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that SDP took.

c. By no later than the dates set forth in Column G of Appendix 2.1 for compliance with the work practice standards in Paragraph 53: (i) SDP shall record each time it manually overrides an Automatic Control System, including the date, time, duration, reason for the override, and corrective actions that SDP took; and (ii) where the reason for the override was to stop Smoke Emissions that were occurring and/or to stop Discontinuous Wake Dominated Flow, SDP shall include a copy of the digital video record (with a time stamp) of the flare during the period of the manual override.

d. By no later than the dates required in Column F of Appendix 2.1 for compliance with the standards in Paragraph 50, and by no later than the dates required in Column H of Appendix 2.1 for compliance with the emissions standards in Paragraphs 56–59, at any time that SDP deviates from those standards, SDP shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that SDP took.

63. Portable Flares.

a. Applicability. The provisions of this Paragraph shall apply to Portable Flares.

b. Distinction between Planned and Unplanned Outages of Covered Flares. For purposes of this Paragraph, a "planned" outage shall mean an outage of a Regular-Use

Covered Flare that is scheduled 30 days or more in advance of the outage. An "unplanned" outage is an outage of a Covered Flare that either is scheduled less than 30 days in advance or is unscheduled.

c. <u>504 hours or less</u>. For any planned or unplanned outage of a Covered Flare that SDP knows or reasonably anticipates will result in 504 hours or less of downtime on a 1095-day rolling sum period, rolled daily, SDP shall make good faith efforts to ensure that the Portable Flare that replaces the Covered Flare complies with all of the requirements of this Consent Decree that are applicable to the Covered Flare that the Portable Flare replaces.

d. <u>More than 504 hours.</u>

i. <u>Planned</u>. For any planned outage of a Regular-Use Covered Flare that SDP knows or reasonably can anticipate will last 504 hours or more on a 1095-day rolling sum period, rolled daily, SDP shall ensure that the Portable Flare complies with all of the requirements of this Consent Decree related to the Regular-Use Covered Flare that it replaces as of the date that the Portable Flare is In Operation and Capable of Receiving Waste, Supplemental, and/or Sweep Gas, except that, in lieu of having to comply with the applicable dynamically-calculated $NHV_{cz\text{-}limit}$ under Subparagraph 56.b or the 355 BTU/scf static $NHV_{cz\text{-}limit}$ under Subparagraph 56.d, SDP shall operate the Portable Flare so that, except as provided in Paragraph 60.b, the Portable Flare's NHV_{cz} is greater than or equal to 325 BTU/scf: (i) on a three-hour rolling average, rolled every fifteen minutes if a gas chromatograph is used to calculate NHV_{cz}; (ii) on a one-hour rolling average, rolled every five minutes if a Net Heating Value Analyzer is used to calculate NHV_{cz}. SDP shall utilize Steps 3 and 6 in Appendix 1.3 to calculate NHV_{cz}.

ii. <u>Unplanned</u>. For any unplanned outage of a Covered Flare that, in advance of the outage, SDP cannot reasonably anticipate will last longer than 504 hours, SDP shall ensure that the Portable Flare complies with all of the requirements of this Consent Decree related to the Covered Flare that it replaces by no later than 30 days after the date that SDP knows or reasonably should have known that the outage will last 504 hours or more, except that, in lieu of having to comply with the applicable dynamically-calculated $NHV_{cz\text{-}limit}$ under Subparagraph 56.b or the 355 BTU/scf static $NHV_{cz\text{-}limit}$ under Subparagraph 56.d, SDP shall operate the Portable Flare so that, except as provided in Paragraph 60.b, the Portable Flare's NHV_{cz} is greater than or equal to 325 BTU/scf: (i) on a three-hour rolling average, rolled every fifteen minutes if a gas chromatograph is used to calculate NHV_{cz}; (ii) on a one-hour rolling average, rolled every five minutes if a Net Heating Value Analyzer is used to calculate NHV_{cz}. SDP shall utilize Steps 3 and 6 in Appendix 1.3 to calculate NHV_{cz}.

iii. SDP shall calculate NHV_{cz} using a Net Heating Value for hydrogen of 1212 BTU/scf if the Portable Flare is equipped with a gas chromatograph for calculating Net Heating Value.

e. Recordkeeping. SDP shall keep records sufficient to document compliance with the requirements of this Paragraph any time it uses a Portable Flare.

I. NSPS Subpart A, J, and Ja Applicability

64. NSPS Subparts A, J, and Ja.

a. NSPS Subparts A and J. As of the Date of Lodging, each SDP Refinery Covered Flare shall continue to be an "affected facility" within the meaning of Subparts A and J of 40 C.F.R. Part 60 and shall comply with all of the requirements of Subparts A and J, including but not limited to 40 C.F.R. §§ 60.104(a)(1) and 60.105(a)(4), by no later than the Date of Lodging and continuing until November 11, 2015.

b. NSPS Subparts A and Ja. Each SDP Refinery Covered Flare shall be an "affected facility" within the meaning of Subparts A and Ja of 40 C.F.R. Part 60, and shall comply with all of the requirements of Subparts A and Ja on and after November 11, 2015. After November 11, 2015, Subpart J shall not apply to the SDP Refinery Covered Flares.

J. Eliminating Fuel Gas Flow from the SDP Refinery to the SDP Chemical Plant Covered Flares

65. SDP shall take all steps necessary to locate and eliminate all connections and/or operations which could allow Fuel Gas from the SDP Refinery to be routed to the SDP Chemical Plant Covered Flares in accordance with these requirements:

a. By no later than December 31, 2014, SDP shall physically remove piping and/or physically isolate piping with a welded blind where such piping potentially allows Fuel Gas to be routed to the Olefins II and Olefins III Flares during emergency situations;

b. By no later than December 31, 2016, SDP shall permanently cease using the Butane Butylene Hydrotreater Unit to process any refinery streams and shall eliminate the possibility that Fuel Gas from such operations may be routed from the Butane Butylene Hydrotreater Unit to the Olefins Flares; and

c. By no later than December 31, 2016, SDP shall discover and permanently eliminate all other potential connections and/or operations which could allow Fuel Gas to be routed to the SDP Chemical Plant Covered Flares.

K. Incorporation of Consent Decree Requirements into Federally Enforceable Permits

66. Permits Needed to Meet Compliance Obligations. If any compliance obligation under this Section V requires SDP to obtain a federal, state, or local permit or approval, SDP shall submit timely and complete applications and take all other actions necessary to obtain all such permits or approvals. SDP may seek relief under the provisions of Section XI of this Decree (Force Majeure) for any delay in the performance of any such obligation resulting from a failure to obtain, or a delay in obtaining, any permit or approval required to fulfill such obligation, if SDP has submitted timely and complete applications and has taken all other actions necessary to obtain all such permits or approvals.

67. Permits to Ensure Survival of Consent Decree Limits and Standards after Termination of Consent Decree.

a. Prior to termination of this Consent Decree, SDP shall submit complete applications to the appropriate permitting authorities in the State of Texas to incorporate the limits and standards listed in Subparagraph 67.b into non-Title V, federally enforceable permits that will survive termination of this Consent Decree. Prior to termination of this Consent Decree, SDP shall submit to the appropriate permitting authorities in the State of Texas, appropriate applications, amendments and/or supplements to incorporate as "applicable requirements" the limits and standards listed in Subparagraph 67.b to ensure that these limits and standards survive termination of this Consent Decree.

b. The limits and standards imposed by the following Paragraphs of this Consent Decree shall survive termination: 17–24, 26–29, 40, 47, 49, 50–51, 53–55, 56.b–d, 57.b–c, 58.c–e, 59–62, 64–65. Nothing in this Paragraph shall prohibit SDP from seeking to incorporate Paragraph 25 in a permit that survives termination of this Decree.

68. Modifications to Title V Operating Permits. Prior to termination of this Consent Decree, SDP shall submit complete applications to the appropriate permitting authorities in the State of Texas to modify, amend, or revise the Title V permit of each Covered Facility to incorporate the limits and standards identified in the preceding Paragraph into the Title V permits. The Parties agree that the incorporation of these emission limits and standards into Title V Permits shall be done in accordance with applicable state or local Title V rules. The Parties agree that the incorporation may be by "amendment" under 40 C.F.R. § 70.7(d) and analogous state Title V rules, where allowed by state law.

VI. EMISSION CREDIT GENERATION

69. Prohibitions.

a. Definition. "CD Emissions Reductions" shall mean any NO_x, SO_2, H_2S, PM, PM_{TOTAL}, PM_{10}, $PM_{2.5}$, VOC, or CO emissions reductions that result from any projects conducted or controls used to comply with this Consent Decree.

b. Prohibitions.

i. SDP shall neither generate nor use any CD Emissions Reductions: as netting reductions; as emissions offsets; to apply for, obtain, trade, or sell any emission reduction credits; or in determining whether a project would result in a significant emissions increase or significant net emissions increase in any PSD, major non-attainment, and/or minor New Source Review permit or permit proceeding. Baseline actual emissions during any 24-month period selected by SDP shall be adjusted downward to exclude any portion of the baseline emissions that would have been eliminated as CD Emissions Reductions had SDP been complying with this Consent Decree during that 24-month period;

ii. Any CD Emissions Reductions that result from the Waste Gas minimization requirements of Paragraphs 30–37 may not be used as netting reductions, as emissions offsets, or in determining whether a project is “major” in any PSD, major non-attainment and/or minor New Source Review permit or permit proceeding even if those Reductions result in emissions lower than the allowable level under the flaring limitations in Paragraph 41. Baseline actual emissions during any 24-month period selected by SDP shall be adjusted downward to exclude any portion of the baseline emissions that would have been eliminated as Waste Gas minimization related CD Emissions Reductions as if SDP previously achieved the reductions during that 24-month period;

iii. Except as provided in Subparagraph 70.b, SDP shall not apply for, obtain, trade, or sell any emission reduction credits that result from CD Emissions Reductions.

70. Outside the Scope of the Prohibition. Nothing in this Section is intended to prohibit SDP from seeking to nor prohibit the State of Texas from denying SDP’s ability to:

a. Use or generate netting reductions or emission reduction credits for refinery units that are not subject to an emission limitation pursuant to this Consent Decree;

b. Use CD Emissions Reductions for the Covered Facilities’ compliance with any rules or regulations designed to address regional haze or the non-attainment status of any area (excluding PSD and Non-Attainment New Source Review rules, but including, for example, RACT rules) that apply to the Covered Facilities; provided, however, that SDP shall not be allowed to trade or sell any CD Emissions Reductions.

VII. MITIGATION PROJECTS

71. SDP shall undertake the "Mitigation Project: North Effluent Treater Controls" set forth in Appendix 2.6 of this Decree in accordance with the requirements of Appendix 2.6.

72. SDP shall undertake the "Mitigation Project: Tank Controls" set forth in Appendix 2.7 of this Decree in accordance with the requirements of Appendix 2.7.

73. SDP shall undertake the "Mitigation Project: ACU and BEU Controls" set forth in Appendix 2.8 of this Decree in accordance with the requirements of Appendix 2.8.

74. By signing this Consent Decree, SDP certifies that it is not required to perform or develop these Mitigation Projects by any federal, state, or local law or regulation and is not required to perform or develop these Projects by agreement, grant, or as injunctive relief awarded in any other action in any forum; that these Projects are not ones that SDP was planning or intending to construct, perform, or implement other than in settlement of the claims resolved by this Decree; and that SDP will not receive any reimbursement for any portion of the costs of these Projects from any other person.

75. Mitigation Project Progress and Completion Reports. SDP shall include in each report required under Paragraph 85, a status update on each Mitigation Project required by this Section. In addition, the report required by Paragraph 85 for the period in which the Project is completed shall contain the following information:

a. A detailed description of the Project as implemented;

b. A description of any problems encountered in completing the Project and the solutions thereto;

c. A description of the environmental and public health benefits resulting from implementation of the Project (with a quantification of the benefits and an estimate of the pollutant reductions); and

d. A certification that the Project has been fully implemented pursuant to the provisions of this Decree.

VIII. SUPPLEMENTAL ENVIRONMENTAL PROJECTS

76. SDP shall implement as a Supplemental Environmental Project ("SEP") a project to install and operate an open path air monitor on the fenceline of the Covered Facilities ("Fence Line Open Path Monitoring SEP"), in accordance with this Paragraph and the criteria, terms, and procedures in Appendix 2.9 of this Consent Decree. SDP shall spend not less than $1 million to implement this SEP. SDP shall undertake the tasks required for implementing the Fence Line Open Path Monitoring SEP in accordance with the schedule required by Appendix 2.9.

77. SDP shall implement a SEP designed to reduce diesel emissions from school buses and/or non-school bus publicly owned vehicles in the vicinity of the Covered Facilities ("Diesel Retrofit SEP") in accordance with this Paragraph and the criteria, terms and procedures in Appendix 2.10. SDP shall spend no less than $200,000 to implement this SEP. No SEP funds shall be used for testing or demonstration. SDP shall complete the implementation of the Diesel Retrofit SEP by no later than 24 months after the Date of Entry.

78. With respect to the Diesel Retrofit SEP, SDP certifies under penalty of law that it would have agreed to perform a comparably valued, alternative project other than a diesel emissions reduction Supplemental Environmental Project if EPA were precluded by law from accepting a diesel emissions reduction Supplemental Environmental Project.

79. SDP is responsible for the satisfactory completion of the Fence Line Monitoring SEP and the Diesel Retrofit SEP as provided in this Consent Decree. SDP may use contractors or consultants in planning and implementing the SEPs.

a. If SDP completes the SEPs in accordance with all applicable requirements but does not expend the entire amount specified in Paragraphs 76 or 77, SDP shall pay the difference between the amount expended as demonstrated in the certified cost report and the amount specified in Paragraphs 76 or 77 (as applicable). The difference shall be paid as provided in Section X of this Consent Decree.

b. As an alternative to payment of such amount, SDP may request, and EPA may, in its sole discretion, approve use of the unexpended SEP funds for an alternative SEP.

80. With regard to the Fence Line Open Path Monitoring and Diesel Retrofit SEPs, SDP certifies the truth and accuracy of each of the following:

a. That all cost information provided to EPA in connection with EPA's approval of these SEPs is complete and accurate and that SDP in good faith estimates that the cost to implement the Fence Line Open Path Monitoring SEP is $1 million and the cost to implement the Diesel Retrofit SEP is $200,000;

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

c. That these SEPs are not projects that SDP was planning or intending to construct, perform, or implement other than in settlement of the claims resolved in this Consent Decree;

d. That SDP has not received and will not receive credit for the SEPs in any other enforcement action;

e. That SDP will not receive any reimbursement for any portion of the SEPs from any other person;

f. That SDP is not a party to any Open Federal Financial Assistance Transaction that is or could be used to fund the same activity as the SEPs; and

g. That, to the best of SDP's knowledge and belief based upon reasonable inquiry:

i. There is no open Federal Financial Assistance Transaction that is funding or could fund the same activity as the SEPs; and

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

81. SDP shall include in each report required by Paragraph 85 of Part IX (Reporting) a description of its progress toward implementing the SEP required by this Section. In addition, the report required by Paragraph 85 for the period in which the SEP is completed will contain the following information with respect to the SEP ("SEP Completion Report"):

a. A detailed description of the SEP as implemented. For the Diesel Retrofit SEP, the description shall include, with respect to each retrofit, the following information:

i. Vehicle owner with contact name and phone number;

ii. Vehicle type (e.g., mass transit bus, school bus);

iii. Model year;

iv. Engine Manufacturer;

v. Actual, or if not known, estimated or projected, annual miles or hours of operation;

vi. Retrofit type (e.g., oxidation catalyst, particulate filter);

vii. Retrofit cost per vehicle (separate out installation costs);

viii. Actual, or if not known, estimated or projected, annual fuel usage (gal/yr);

ix. Actual, or if not known, estimated or projected, annual emissions reductions (PM, HC, CO);

x. Copy of invoices for purchase of control technology;

xi. Name of the technology installed as identified on the EPA or CARB webpages:

http://www.epa.gov/otaq/retrofit/verif-list.htm

http://www.epa.gov/otaq/smartway/transport/what-smartway/verified-technologies.htm#idle http://www.arb.ca.gov/diesel/verdev/vt/cvt.htm

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

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

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

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

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

82. Disputes concerning the satisfactory performance of the Fence Line Monitoring and Diesel Retrofit SEPs and the amount of eligible SEP costs may be resolved under Section XII of this Decree ("Dispute Resolution"). No other disputes arising under this Section shall be subject to Dispute Resolution.

83. Any public statement, oral or written, in print, film, or other media, made by SDP and referring to one and/or both of the SEPs under this Decree shall include the following language: "This project was undertaken in connection with the settlement of an enforcement action, United States v. Shell Oil Co., *et al.*, taken on behalf of the EPA under the Clean Air Act."

84. For federal income tax purposes, SDP agrees that it will neither capitalize into inventory or basis nor deduct any costs or expenditures incurred in performing either the Fence Line Monitoring SEP or the Diesel Retrofit SEP.

IX. REPORTING REQUIREMENTS

85. Semi-Annual Reports. On the dates and for the time periods set forth in Paragraph 88, SDP shall submit to EPA in the manner set forth in Section XVI (Notices) the following information:

a. A progress report on the implementation of the requirements in Section V of this Decree (Compliance Requirements) at the Covered Facilities;

b. A description of any problems anticipated with respect to meeting the requirements of Section V at the Covered Facilities;

c. A description of the status of the Mitigation Projects in Section VII of this Decree (Mitigation Project);

d. A description of the status of the SEPs in Section VIII of this Decree;

e. Monitoring equipment/instrument downtime; override of Automatic Control System ("ASC"); exceedances of emission standards; and compliance with compressor availability requirements; as described in Paragraph 86;

f. For the semi-annual report due on July 31 of each year, annual emissions data, as described in Paragraph 87;

g. Any additional matters required by any other Paragraph of this Consent Decree to be submitted in the semi-annual report; and

h. Any additional matters that SDP believes should be brought to the attention of EPA.

86. Monitoring Instrument/Equipment Downtime; Override of ACS; and Emissions Exceedances. On and after the date of applicability of any work practice or standard, SDP shall provide a summary of the following, per Covered Flare per calendar quarter (hours shall be rounded to the nearest tenth):

a. Monitoring Instrument/Equipment Downtime. The total number of hours of downtime of each monitoring instrument/equipment required pursuant to Paragraphs 18–20 and 22–24 expressed as both an absolute number and a percentage of time the Covered Flare that the instrument/equipment monitors is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas;

b. Monitoring Instrument/Equipment Downtime. If the total number of hours of downtime of any monitoring instrument/equipment required pursuant to Paragraphs 18–20 and 22–24 exceeds 110 hours in any calendar quarter (for a Regular-Use Covered Flare) or 5% of the operating time (for a Temporary-Use Covered Flare or Portable Flare), an identification of the periods of downtime by date, time, cause (including Malfunction or maintenance), and, if the cause is asserted to be a Malfunction, the corrective action taken;

c. Override of Automatic Control System. The total number of hours in which SDP manually overrode the ACS required in Paragraph 53, expressed both as an absolute number of hours and a percentage of time the Covered Flare was In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas; provided however, that for any hour identified, the report shall describe either or both of the following: (i) if the reason for the override was one of the exceptions identified in Paragraph 54, a statement of which exception; or (ii) if the total number of hours in which the ACS was overridden was less than 110 hours (for a Regular-Use Covered Flare) or less than 5% of the operating time (for a Temporary-Use Covered Flare) and was caused by one or more of the exceptions identified in Paragraph 60, a statement to that effect;

d. Override of Automatic Control System. If the reason for the override was not one of the exceptions set forth in Paragraph 54 or if the total number of hours in which the ACS was overriden exceeds 110 hours in any calendar quarter (for a Regular-Use Covered Flare) or 5% of the operating time (for a Temporary-Use Covered Flare), an identification of the periods of override by the date, time, duration, reason for the override, and corrective actions taken;

e. Inapplicability of Emissions Standards. The total number of hours, expressed as both an absolute number of hours and a percentage of time that the Covered Flare was In Operation, in which the requirements of Paragraphs 56–59 were not applicable because the only gas or gases being vented was/were Pilot Gas and/or Purge Gas; for purposes of Subparagraphs 86.f. and 86.g, all remaining hours shall be termed "Hours of Applicability";

f. Exceedances of Emissions Standards. During the Hours of Applicability, the total number of hours, expressed as both an absolute number of hours and a percentage of time the Covered Flare was In Operation, of exceedances of the emissions standards in Subparagraphs 56.b–d, 57.b, 58.c–d, and 59; provided however, that if the exceedance of these standards was less than 110 hours in the calendar quarter (for Regular-Use Covered Flares) or 5% of the total Hours of Applicability (for Temporary-Use Covered Flares) and was due to one or more of the exceptions set forth in Paragraph 60, the report shall so note;

g. Exceedances of Emissions Standards. During the Hours of Applicability, if the exceedance of the emissions standards in Subparagraphs 56.b–d, 57.b, 58.c–d, and 59 was not due to one of the exceptions in Paragraph 60, or if the exceedance was due to one or more of the exceptions in Paragraph 60 but the total number of hours caused by the exceptions in Paragraph 60 was greater than 110 (for Regular-Use Covered Flares) or 5% of the total Hours of Applicability (for Temporary-Use Covered and Portable Flares), an identification of each block period that exceeded the standard, by time and date; the cause of the exceedance (including Startup, Shutdown, maintenance, or Malfunction), and if the cause is asserted to be a Malfunction, an explanation and any corrective actions taken;

h. Flaring Limitations Exceedances.

   i. For any Waste Gas flows that are excluded from the calculation of flow rate because they are asserted to be based on one or more of the excludible events identified in Subparagraph 44.b, the information required in Subparagraph 44.c;

   ii. An identification of each calendar day in which the limitations on flaring set forth in Paragraph 41 were exceeded;

   iii. The cause of the exceedance; and

   iv. If the cause is asserted to be a Malfunction, an explanation and any corrective actions taken;

i. Intentionally Left Blank; and

j. Compliance with Compressor Availability Requirements. In each semi-annual report starting on and after July 31, 2015 (for the compressors within the FGRS systems at the SDP Refinery), and in each semi-annual report starting on and after January 31, 2019 (for the compressors within the Olefins FGRS), SDP shall provide sufficient information to document compliance with the Compressor availability requirements of Subparagraph 40.b (for the SDP Refinery FGRS Compressors) and Subparagraph 47.b (for SDP Olefins FGRS Compressors). For any period of non-compliance, SDP shall identify the date, cause, and corrective action taken.

87. Emissions Data. In the semi-annual report that is submitted on July 31 of each year, SDP shall provide, for each Covered Flare, for the prior calendar year, the amount of emissions of the following compounds (in tons per year): VOCs, SO_2, H_2S, CO_2, methane, and ethane.

88. Due Dates. The first compliance status report shall be due thirty-one days after the first full half-year after the Effective Date of this Consent Decree (*i.e.*, either: (i) January 31 of the year after the Effective Date, if the Effective Date is between January 1 and June 30 of the preceding year; or (ii) July 31 of the year after the Effective Date, if the Effective Date is between July 1 and December 31). The initial report shall cover the period between the Effective Date and the first full half year after the Effective Date (a "half year" runs between January 1 and June 30 and between July 1 and December 31). Until termination of this Decree, each subsequent report will be due on January 31 and July 31 and shall cover the prior half year (*i.e.*, January 1 to June 30 or July 1 to December 31). Whenever this Consent Decree requires compliance within a certain number of "months" after a triggering event, the compliance obligation commences on the anniversary of the numerical date that triggers the obligation. For example, if compliance is required by no later than three months after the submission of a particular document, and if the document is submitted on March 23, 2012, the compliance obligation commences on June 23, 2012.

89. Each report submitted under this Consent Decree shall be signed by the Covered Facilities' Manager (or his/her designee), the person responsible for environmental management at the Covered Facilities, or by a person responsible for overseeing implementation of this Consent Decree across SDP, and shall include the following certification:

> I certify under penalty of law that this document and all attachments were 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 inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete.

90. The reporting requirements of this Consent Decree do not relieve SDP of any reporting obligations required by the CAA or implementing regulations, or by any other federal, state, or local law, regulation, permit, or other requirement.

91. Any information provided pursuant to this Consent Decree may be used by the United States in any proceeding to enforce the provisions of this Consent Decree and as otherwise permitted by law.

X. STIPULATED PENALTIES

92. Failure to Pay Civil Penalty. If SDP fails to pay any portion of the civil penalty required to be paid under Section IV of this Decree (Civil Penalty) when due, SDP shall pay a stipulated penalty of $2500 per day for each day that the payment is late. Late payment of the civil penalty and any accrued stipulated penalties shall be made in accordance with Paragraph 13.

93. Failure to Meet all Other Consent Decree Obligations. SDP shall be liable for stipulated penalties to the United States for violations of this Consent Decree as specified below unless excused under Section XI of this Decree (Force Majeure). 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 rests exclusively within the discretion of the United States. For a given calendar day, where a failure to comply with the 30-day and/or the 365-day rolling average limit on Waste Gas flaring at the SDP Refinery required by Subparagraph 41.a of this Decree (and potentially subject to the stipulated penalty

provisions of Subparagraphs 93.l and/or 93.m) is the result of a failure to have the requisite number of Compressors Available for Operation as required by Subparagraph 40.b of this Decree (and potentially subject to the stipulated penalty provisions of Subparagraphs 93.j and/or 93.k), only the stipulated penalty provision that results in the higher penalty shall be applicable for that calendar day (*i.e.*, stipulated penalties under *both* Subparagraph 93.l and/or 93.m *and* Subparagraph 93.j and/or 93.k shall not be assessed). Nothing in the previous sentence shall be construed to result in only one penalty being applicable on any given calendar day for violations of both the 30-day and the 365-day rolling average limits on Waste Gas flaring (*i.e.*, for any given calendar day in which both the 30-day and 365-day rolling average limits are violated, stipulated penalties under *both* Subparagraph 93.l. and 93.m may be assessed).

Violation	**Stipulated Penalty**	
93.a. Violation of Paragraph 16. Failure to timely submit a report (¶ 16) that conforms to the requirements of that Paragraph	Period of delay or noncompliance Days 1–30 Days 31–60 Days 61 and later	Penalty per day $ 300 $ 400 $ 500
93.b. Violation of Paragraph 30, 31, or 32. Failure to timely submit a plan (¶¶ 30, 31, or 32) that conforms to the requirements of the respective Paragraph	Period of delay or noncompliance Days 1–30 Days 31–60 Days 61 and later	Penalty per day $ 500 $ 750 $ 1000

93.c. Violation of Paragraph 17, 18, 19, 20, 21, 22, 23, 24, 26, or 27. Failure to timely install the equipment and monitoring systems required by Paragraphs 18–24 in accordance with the respective, applicable technical specifications in those Paragraphs, Paragraphs 26–27, and Appendix 1.10 (except for the requirements of Appendix 1.10 found in Subparagraphs I.g, III.e, IV, V.B, or VII.a: those are QA/QC requirements covered in Subparagraph 93.d below)	Period of delay or noncompliance, per monitoring system Days 1–30 Days 31–60 Days 61 and later	Penalty per day per monitoring system $ 750 $ 1250 $ 2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater
93.d. Violation of the QA/QC requirements in Appendix 1.10. Failure to comply with the QA/QC requirements in Appendix 1.10 at Subparagraphs I.g, III.e, IV, V.B, and VII.a	Violation of a: Daily requirement Quarterly requirement Annual requirement	Penalty $ 100 $ 200 per day late $ 500 per day late
93.e Violation of Paragraph 28: Regular-Use Covered Flares. After the dates in Column H of Appendix 2.1, except for 110 hours per calendar quarter, failure to operate the monitoring systems in Paragraphs 18–20 and 22–24; provided however, that SDP shall not be liable for a stipulated penalty for violation of Paragraph 28 if, during the period of instrument downtime, the only gas(es) being sent to the Regular-Use Covered Flare in question is/are Purge Gas and/or Pilot Gas. For any monitoring system that serves a dual purpose, this stipulated penalty applies per instrument only.	Per monitoring system, number of hours per calendar quarter of downtime over 110 0.25–50.0 50.25–100.0 Over 100.0	Penalty per hour per monitoring system $ 250 $ 500 $ 1000

93.f. <u>Violation of Paragraph 28: Temporary-Use Covered Flares</u>. After the dates in Column H of Appendix 2.1, except for 5% per uninterrupted period of time that a Temporary-Use Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas, failure to operate the monitoring systems in Paragraphs 18–20 and 22–24; provided however, that SDP shall not be liable for a stipulated penalty for violation of Paragraph 28 if, during the period of instrument downtime, the only gas(es) being sent to the Temporary-Use Covered Flare in question is/are Purge Gas and/or Pilot Gas. For any monitoring system that serves a dual purpose, this stipulated penalty applies per instrument only.	Per monitoring system, number of hours per uninterrupted period <u>of time</u> 0.25–50.0 50.25–100.0 Over 100.0	Penalty per hour per monitoring <u>system</u> $ 250 $ 500 $ 1000
93.g. <u>Violation of Paragraph 35</u>. Failure to timely develop a report that conforms to the requirements in Subparagraph 35.a; or failure to keep it as an internal record; or failure to timely submit a summary of the flaring incident reports that conforms to the requirements in Subparagraph 35.b	Period of delay or <u>noncompliance</u> Days 1 – 30 Days 31 – 60 Days 61 and later	<u>Penalty per day</u> $ 800 $ 1,600 $ 3,000
93.h. <u>Violation of Paragraph 36</u>. Failure to complete any corrective action under Paragraph 36 in accordance with the schedule for corrective action agreed to by SDP or imposed on SDP pursuant to the dispute resolution provisions of this Decree (with any such extensions thereto as to which EPA and SDP may agree in writing)	Period of delay or <u>noncompliance</u> Days 1 – 30 Days 31 – 60 Days 61 and later	<u>Penalty per day</u> $ 1,000 $ 2,000 $ 5,000

93.i. <u>Violation of Paragraph 39 or Paragraph 45</u>. Failure to timely install, in accordance with Paragraph 39 or Paragraph 45 (as applicable), a Flare Gas Recovery System that conforms to the requirements of Paragraph 39 or Paragraph 45(as applicable)	<u>Period of delay or noncompliance, per FGRS</u> Days 1–30 Days 31–60 Days 61 and later	<u>Penalty per day per FGRS</u> $ 1250 $ 3000 $ 5000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater
93.j. <u>Violation of Certain Subparagraph 40.b.ii or Subparagraph 47.b.ii requirements.</u> For each failure to comply with the Subparagraph 40.b.ii requirement to have four Compressors Available for Operation and/or in operation "at all times," or for each failure to comply with the Subparagraph 47.b.ii requirement to have "n-2" Compressors Available for Operation and/or in operation "at all times"	Per FGRS, per hour or fraction thereof: $750; provided however, that stipulated penalties shall not apply for any hour in which a Compressor's unavailability did not result in flaring	
93.k. <u>Violation of Certain Subparagraph 40.b or Subparagraph 47.b Requirements (excluding those identified in Subparagraph 93.j)</u>. For each failure to comply with the following requirements in Subparagraph 40.b. or Subparagraph 47.b: *(1)* Subparagraph 40.b.i or Subparagraph 47.b.i requirement to have one Compressor Available for Operation and/or in operation 98% of the time; *(2)* Subparagraph 40.b.i or Subparagraph 47.b.i requirement to have two Compressors Available for Operation and/or in operation 90% of the time; *(3)* Subparagraph 40.b.ii or Subparagraph 47.b.ii requirement to have five Compressors or "n-1" Compressors, respectively, Available for Operation and/or in operation 95% of the time	Per FGRS, the number of hours or fraction thereof–over the allowed percentage—in a rolling 8760-hour period that a Compressor required to be Available for Operation is not: $750; provided however, that stipulated penalties shall not apply for any hour or fraction thereof in which a Compressor's unavailability did not result in flaring.	

93.l. <u>Violation of Paragraph 41.a.i</u> Failure to comply with the 30-day rolling average limit on Waste Gas flaring at the SDP Refinery	<u>Pollutant</u> <u>Penalty per Day per ton</u> SO_2 \$ 100 VOC \$ 300 The amount of excess emissions during the event(s) which precipitate(s) the exceedance(s) of the 30-day rolling average limit is not the sole basis for calculating the stipulated penalty due. Instead, each day on which the 30-day rolling average limit is violated —which violations most likely continue even though the precipitating event and the excess emissions do not — counts as a separate day. SDP shall comply with Appendix 1.13 to calculate the stipulated penalties resulting from violating the flaring limitation in Paragraph 41.a.i.
93.m. <u>Violation of Paragraph 41.a.ii.</u> Failure to comply with the refinery-wide 365-day rolling average limit on Waste Gas flaring at the SDP Refinery	<u>Pollutant</u> <u>Penalty per Day per ton</u> SO_2 \$ 40 VOC \$ 120 The amount of excess emissions during the event(s) which precipitate(s) the exceedance(s) of the 365-day rolling average limit is not the sole basis for calculating the stipulated penalty due. Instead, each day on which the 365-day rolling average limit is violated—which violations most likely continue even though the precipitating event and the excess emissions do not—counts as a separate day. SDP shall comply with Appendix 1.13 to calculate the stipulated penalties resulting from violating the flaring limitation in Paragraph 41.a.ii.

93.n. <u>Violation of Paragraph 48</u>. Failure to timely convert the A&S Flare to Temporary-Use in conformance with the requirements of Paragraph 48.	Period of delay or <u>noncompliance</u> — <u>Penalty per day</u> Days 1–30 — $ 1000 Days 31–60 — $ 2500 Days 61 and later — $ 5000
93.o. <u>Violation of Paragraph 49</u>. Failure to comply with the 365-day rolling sum emission limit on VOCs from the HIPA Flare	$2500 per calendar day on which the limit is exceeded
93.p. <u>Violation of Paragraph 53</u>. Failure to timely install and operate, by the dates in Column G of Appendix 2.1, the Automatic Control System requirements of Paragraph 53	Penalty per Covered Flare per day: $500
93.q. <u>Violation of Subparagraph 56.b, 56.c, or 56.d.</u> For each Covered Flare, failure to comply with the Net Heating Value in the Combustion Zone Gas ("NHV_{cz}") standard in Subparagraph 56.b, 56.c, or 56.d.	On a per Covered Flare basis, hours per calendar <u>quarter in noncompliance</u> — Penalty per hour, or fraction there of <u>per flare</u> Hours 0.25–50.0 — $ 25 Hours 50.25–100.0 — $ 75 Hours over 100.0 — $ 150 For purposes of calculating the number of hours of noncompliance with the NHV_{cz} standard, all 15-minute periods of violation shall be added together to determine the total.
93.r. <u>Violation of Subparagraph 57.a.</u> Between the Date of Lodging and the compliance dates in Column H of Appendix 2.1, failure to use best efforts to maintain the S/VG ratio at each Covered Flare below 3.0; provided, however, that SDP shall not be liable for a stipulated penalty for violation of Subparagraph 57.a if, at the Covered Flare in question, SDP can demonstrate that it is complying with the requirements of Subparagraphs 56.b, 56.c, or 56.d (as applicable) during the period of applicability of this stipulated penalty.	Penalty per Covered Flare per day or fraction thereof: $1500

93.s. Violation of Subparagraph 58.c. Failure to comply with the prohibition on Discontinuous Wake Dominated Flow	Flare Tip Size (inches) — Penalty per hour or fraction thereof 1.0–24.0 — $ 150 24.1–48.0 — $ 225 Over 48.0 — $ 525
93.t. Violation of Subparagraph 58.d. Failure to comply with the applicable MFR standard	Flare Tip Size (inches) — Penalty per hour or fraction thereof 1.0–24.0 — $ 50 24.1–48.0 — $ 75 Over 48.0 — $ 175 For purposes of calculating the number of hours of noncompliance with the MFR limit, all 5-minute periods of violation shall be added together to determine the total.
93.u. Violation of Paragraph 62. Failure to record any information required to be recorded pursuant to Subparagraphs 62.a, b, c, or d	$100 per day
93.v. Violation of Subparagraphs 63.d.i or 63.d.ii. Failure to ensure that a Portable Flare that falls under the conditions of Subparagraph 63.d.i or 63.d.ii complies with the requirements of those Subparagraphs	Number of days Portable Flare did not comply — Penalty per day Days 1–7 — $ 1000 Days 8–15 — $ 2000 Days 16 and later — $ 5000
93.w. Violation of Paragraph 64. Failure to comply with the H_2S emission limit at a Refinery Covered Flare after that Refinery Covered Flare is required to comply with 40 C.F.R. Part 60, Subpart J, or 40 C.F.R. Part 60, Subpart Ja	On a per Covered Flare basis, hours (on a three-hour rolling average basis) per calendar quarter in noncompliance — Penalty per hour per Covered Flare Hours 1–50.0 — $ 50 Hours 51–100.0 — $ 100 Hours over 100.0 — $ 200 For purposes of calculating the number of hours of noncompliance with the H_2S limit, all one-hour periods of violation shall be added together to determine the total. The averaging period for this standard is a three-hour rolling average.

93.x. Violation of Paragraph 65. Failure to timely comply with the requirements of Paragraph 65	Period of delay Days 1 – 30 Days 31 – 60 Days 61 and later	Penalty per day $ 1,000 $ 2,000 $ 5,000
93.y. Violation of Paragraphs 71–73, and Appendices 2.6–2.8. For failure to comply with any requirement of Paragraphs 71–73 or Appendices 2.6–2.8	Period of delay or noncompliance Days 1–30 Days 31–60 Days 61 and later	Penalty per day $ 500 $ 1500 $ 3000
93.z. Violation of Paragraphs 76–77 and Appendices 2.9–2.10. For failure to comply with any requirement of Paragraphs 76–77 and Appendices 2.9–2.10	Period of delay or noncompliance Days 1–30 Days 31–60 Days 61 and later	Penalty per day $ 500 $ 1500 $ 3000
93.aa. Violation of Section IX (Reports). For each failure to submit reports as required by Section IX	Period of delay or noncompliance per report Days 1–30 Days 31–60 Days 61 and later	Penalty per day per report $ 300 $ 1000 $ 2000

94. Waiver of Payment. The United States may, in its unreviewable discretion, reduce or waive payment of stipulated penalties otherwise due to it under this Consent Decree.

95. Demand for Stipulated Penalties. A written demand by the United States for the payment of stipulated penalties will identify the particular violation(s) to which the stipulated penalty relates; the stipulated penalty amount (as can be best estimated) that the United States is demanding for each violation; the calculation method underlying the demand; and the grounds upon which the demand is based. Prior to issuing a written demand for stipulated penalties, the United States may, in its unreviewable discretion, contact SDP for informal discussion of matters that the United States believes may merit stipulated penalties.

96. Stipulated Penalties Accrual. Stipulated penalties will begin to accrue on the day after performance is due or the day a violation occurs, whichever is applicable, and, except as provided in Paragraph 99, shall continue to accrue until performance is satisfactorily completed or the violation ceases. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree.

97. Stipulated Penalties Payment Due Date. Stipulated penalties shall be paid no later than sixty (60) days after receipt of a written demand by the United States unless the demand is disputed through compliance with the requirements of the dispute resolution provisions of this Decree.

98. Manner of Payment of Stipulated Penalties. Stipulated penalties owing to the United States of under $10,000 shall be paid by check and made payable to the "U.S. Department of Justice," referencing DOJ Number 90-5-2-1-09388/1 and USAO File Number 2012VO1637, and delivered to the U.S. Attorney's Office in the Southern District of Texas, 1000 Louisiana St., Suite 2300, Houston, TX 77002. Stipulated penalties owing to the United States of $10,000 or more shall be paid in the manner set forth in Section IV of this Decree (Civil Penalty). All transmittal correspondence shall state that the payment is for stipulated penalties, shall identify the violations to which the payment relates, and shall include the same identifying information required by Paragraph 13.

99. Disputes over Stipulated Penalties. By no later than 60 days after receiving a demand for stipulated penalties, SDP may dispute liability for any or all stipulated penalties demanded by invoking the dispute resolution procedures of Section XII of this Decree (Dispute Resolution). In the event of a dispute over stipulated penalties, stipulated penalties shall not accrue commencing on the later of either: (i) the date that, during dispute resolution under

Section XII, the United States and SDP agree upon; or (ii) the date that SDP files a motion with the Court under Paragraph 113; provided however, that in order for stipulated penalties to cease accruing pursuant to either (i) or (ii), SDP must place the disputed amount in an interest-bearing commercial escrow account. If the dispute thereafter is resolved in SDP's favor, the escrowed amount plus accrued interest will be returned to SDP; otherwise, the United States will be entitled to the amount determined by the Court to be due, plus interest that has accrued on such amount in the escrow account.

100. No amount of the stipulated penalties paid by SDP shall be used to reduce its federal tax obligations.

101. Subject to the provisions of Section XIV of this Decree (Effect of Settlement/Reservation of Rights), the stipulated penalties provided for in this Decree shall be in addition to any other rights, remedies, or sanctions available to the United States for a violation of this Consent Decree or applicable law. In addition to injunctive relief or stipulated penalties, the United States may seek mitigating emissions reductions equal to or greater than the excess amounts emitted if the violations result in excess emissions. SDP reserves the right to oppose the United States' request for mitigating emission reductions. SDP shall be allowed a credit, for any stipulated penalties paid, against any statutory penalties imposed for such violation.

XI. FORCE MAJEURE

102. "Force Majeure," for purposes of this Consent Decree, is defined as any event beyond the control of SDP, its contractors, or any entity controlled by SDP that delays the performance of any obligation under this Consent Decree despite SDP's best efforts to fulfill the obligation. The requirement that SDP exercise "best efforts to fulfill the obligation" includes using best efforts to anticipate any potential Force Majeure event and best efforts to address the

effects of any such event: (a) as it is occurring; and (b) after it has occurred, to prevent or minimize any resulting delay.

103. "Force Majeure" does not include SDP's financial inability to perform any obligation under this Consent Decree. Unanticipated or increased costs or expenses associated with the performance of SDP's obligations under this Consent Decree shall not constitute circumstances beyond SDP's control nor serve as the basis for an extension of time under this Section XI.

104. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree, whether or not caused by a Force Majeure event, SDP shall notify EPA in writing not later than fifteen calendar days after the time SDP first knew or should have known by the exercise of due diligence that the event might cause a delay. In the written notice, SDP shall specifically reference this Paragraph 104 of the Consent Decree and shall provide an explanation and description of the reasons for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to prevent or mitigate the delay or the effect of the delay; SDP's rationale for attributing such delay to a Force Majeure event if it intends to assert such a claim; and a statement as to whether, in the opinion of SDP, such event may cause or contribute to an endangerment to public health, welfare, or the environment. SDP shall be deemed to know of any circumstance of which SDP, any entity controlled by SDP, or SDP's contractors knew or should have known. SDP shall include with any notice all available documentation supporting the claim that the delay was attributable to a Force Majeure. The written notice required by this Paragraph shall be effective upon the mailing of the same by

overnight mail or by certified mail, return receipt requested, to EPA in the manner set forth in Section XVI of this Decree (Notices).

105. Failure by SDP to comply with the requirements in Paragraph 104 shall preclude SDP from asserting any claim of Force Majeure for the event for the period of time of such failure to comply, and for any additional delay caused by such failure.

106. If EPA agrees that the delay or anticipated delay is attributable to a Force Majeure event, the time for performance of the obligations under this Consent Decree that are affected by the Force Majeure event will be extended by EPA for such time as is necessary to complete those obligations. An extension of the time for performance of the obligations affected by the Force Majeure event shall not, of itself, extend the time for performance of any other obligation. EPA will notify SDP in writing of the length of the extension, if any, for performance of the obligations affected by the Force Majeure event.

107. If EPA does not agree that the delay or anticipated delay has been or will be caused by a Force Majeure event, or if the EPA and SDP fail to agree on the length of the delay attributable to the Force Majeure event, EPA will notify SDP of its decision.

108. If SDP elects to invoke the dispute resolution procedures set forth in Section XII of this Decree (Dispute Resolution), it shall do so no later than 45 days after receipt of EPA's notice. In any such proceeding, SDP shall have the burden of demonstrating by a preponderance of the evidence that the delay or anticipated delay has been or will be caused by a Force Majeure event, that the duration of the delay or the extension sought was or will be warranted under the circumstances, that best efforts were exercised to avoid and mitigate the effects of the delay, and that SDP complied with the requirements of Paragraphs 102 and 104. If SDP carries this burden,

the delay at issue shall be deemed not to be a violation by SDP of the affected obligation of this Consent Decree identified to EPA and the Court.

XII. DISPUTE RESOLUTION

109. Unless otherwise expressly provided for in this Consent Decree, the dispute resolution procedures of this Section shall be the exclusive mechanism to resolve disputes arising under or with respect to this Consent Decree.

A. For All Disputes Except those Arising Under Subparagraphs 43.c and 46.c

110. Informal Dispute Resolution. The first stage of dispute resolution shall consist of informal negotiations. The dispute shall be considered to have arisen when one Party sends the other Party a written Notice of Dispute. Such Notice of Dispute shall state clearly the matter in dispute. The period of informal negotiations shall not exceed 60 days after the Notice of Dispute, unless that period is modified by written agreement. If the Parties cannot resolve the dispute by informal negotiations, then the position advanced by the United States shall be considered binding unless within 45 days after the conclusion of the informal negotiation period, SDP invokes formal dispute resolution procedures set forth below.

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

112. The United States shall serve its Statement of Position within 45 days of receipt of SDP's Statement of Position. The United States' Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting that position and any

supporting documentation relied upon by the United States. The United States' Statement of Position shall be binding on SDP unless SDP files a motion for judicial review of the dispute in accordance with the following Paragraph.

113. SDP may seek judicial review of the dispute by filing with the Court and serving, in accordance with Section XVI of this Decree (Notices), on the United States a motion requesting judicial resolution of the dispute. The motion must be filed within 45 days of receipt of the United States' Statement of Position pursuant to the preceding Paragraph. The motion shall contain a written statement of SDP's position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief requested and any schedule within which the dispute must be resolved for orderly implementation of the Consent Decree.

114. The United States shall respond to SDP's motion within the time period allowed by the Local Rules of this Court for responses to dispositive motions. SDP may file a reply memorandum, to the extent permitted by the Local Rules.

115. In a formal dispute resolution proceeding under this Section, SDP shall bear the burden of demonstrating that its position complies with this Consent Decree and the CAA and that it is entitled to relief under applicable principles of law. The United States reserves the right to argue that its position is reviewable only on the administrative record and must be upheld unless arbitrary and capricious or otherwise not in accordance with law, and SDP reserves the right to argue to the contrary.

116. The invocation of dispute resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of SDP under this Consent Decree, unless and until final resolution of the dispute so provides. Stipulated penalties with respect to

the disputed matter shall accrue in accordance with Paragraph 99, but payment shall be stayed pending resolution of the dispute.

B. For Disputes Arising Under Subparagraphs 43.c and 46.c

117. For disputes arising under Subparagraphs 43.c and/or 46.c, the provisions of this Subsection XII.B shall apply if SDP invokes the accelerated dispute resolution as allowed by Subparagraphs 43.c or 46.c. Paragraphs 110-116 are incorporated herein by reference except for the following changes:

Reference	Instead Of	Use
Para. 110; 4th Sentence	60 days	15 days
Para. 110; 5th Sentence	45 days	10 days
Para. 112; 1st Sentence	45 days	15 days
Para. 113; 2nd Sentence	45 days	15 days
Para. 114; 1st Sentence	"within the time period allowed by the Local Rules of this Court for responses to dispositive motions"	"within 21 days"

118. If a dispute under Subparagraphs 43.c or 46.c comes before this Court for disposition, both Parties jointly shall advise the Court that time is of the essence.

XIII. INFORMATION COLLECTION AND RETENTION

119. The United States and its representatives, employees, contractors, and consultants shall have the right of entry into the Covered Facilities, at all reasonable times, upon presentation of credentials and any other documentation required by law, to:

a. monitor the progress of activities required under this Consent Decree;

b. verify any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtain documentary evidence, including photographs and similar data, relevant to compliance with the terms of this Consent Decree; and

d. assess SDP's compliance with this Consent Decree.

120. Except for data recorded by any video camera that may be required pursuant to Paragraph 24, until one year after termination of this Consent Decree, SDP shall retain all documents, records, or other information, regardless of storage medium (*e.g.*, paper or electronic) in its possession or control that directly relate to SDP's performance of its obligations under this Consent Decree. Except for data recorded by any video camera that may be required pursuant to Paragraph 24, until one year after termination of this Consent Decree, SDP shall instruct its contractors and agents to preserve all documents, records, or other information, regardless of storage medium (*e.g.*, paper or electronic) in its contractors' or agents' possession or control, or that come into its or its contractors' or agents' possession or control, that demonstrate or document SDP's compliance or non-compliance with the obligations of this Consent Decree. This information-retention requirement shall apply regardless of any contrary corporate or institutional policies or procedures. At any time during this information-retention period, the United States may request copies of any documents, records, or other information required to be maintained under this Paragraph. SDP shall retain the data recorded by any video camera required pursuant to Paragraph 24 for six months from the date of recording except that SDP shall keep any such video record until one year after termination if SDP was required to keep the record pursuant to Subparagraph 62.c.

121. Except for emissions data, SDP may assert that information required to be provided under this Section is protected as Confidential Business Information ("CBI") under 40 C.F.R. Part 2. As to any information that SDP seeks to protect as CBI, SDP shall follow the procedures set forth in 40 C.F.R. Part 2, where applicable.

122. This Consent Decree in no way limits or affects any right of entry and inspection, or any right to obtain information, held by the United States pursuant to applicable federal laws, regulations, or permits, nor does it limit or affect any duty or obligation of SDP to maintain documents, records, or other information imposed by applicable federal or state laws, regulations, or permits.

XIV. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

123. Definitions. For purposes of this Section XIV, the following definitions apply:

a. "BTU/scf Flared Gas Requirements" shall mean the requirements found in the following regulations:

i. 40 C.F.R. § 60.18(c)(3)(ii);

ii. 40 C.F.R. § 63.11(b)(6)(ii);

iii. 40 C.F.R. §§ 60.482-10(d), 60.482-10a(d), but only to the extent that these provisions require compliance with 40 C.F.R. § 60.18(c)(3)(ii);

iv. 40 C.F.R. §§ 60.592(a), 60.592a(a), but only to the extent that these provisions: *(1)* relate to flares; and *(2)* require compliance with 40 C.F.R. § 60.18(c)(3)(ii);

v. 40 C.F.R. § 63.643(a)(1), but only to the extent that this provision requires compliance with 40 C.F.R. § 63.11(b)(6)(ii);

vi. 40 C.F.R. § 63.648(a), but only to the extent that this provision: *(1)* relates to flares; and *(2)* requires compliance with 40 C.F.R. § 60.18(c)(3)(ii);

vii. 40 C.F.R. § 61.349(a)(2)(iii), but only to the extent that this provision requires compliance with 40 C.F.R. § 60.18(c)(3)(ii);

viii. 40 C.F.R. § 63.1566(a)(1)(i) and Table 15, but only to the extent that these provisions: *(1)* relate to flares; and *(2)* require compliance with 40 C.F.R. § 63.11(b)(6)(ii); and

ix. 40 C.F.R. § 63.113(a)(1)(i), but only to the extent that this provision requires compliance with 40 C.F.R. § 63.11(b)(6)(ii).

b. "General Flare Requirements" shall mean the requirements found in the following regulations:

   i. 40 C.F.R. § 60.18(c)(1) and
   40 C.F.R. § 63.11(b)(4)
   (both relate to a prohibition on visible emissions);

   ii. 40 C.F.R. § 60.18(c)(2) and
   40 C.F.R. § 63.11(b)(5)
   (both relate to flame presence);

   iii. 40 C.F.R. § 60.18(c)(4) and
   40 C.F.R. § 63.11(b)(7)
   (both relate to exit velocity requirements for steam-assisted flares); and

   iv. 40 C.F.R. § 60.18(e) and
   40 C.F.R. § 63.11(b)(3)
   (both relate to operation during emissions venting).

c. "Good Air Pollution Control Practice Requirements" shall mean the requirements found in the following regulations:

   i. 40 C.F.R. § 60.11(d);

   ii. 40 C.F.R. § 61.12(c);

   iii. 40 C.F.R. § 63.6(e)(1)(i);

   iv. 40 C.F.R. Part 63, Subpart CC, Table 6, but only to the extent that Table 6 requires compliance with 40 C.F.R. § 63.6(e)(1)(i); and

   v. 40 C.F.R. Part 63, Subpart UUU, Table 44, but only to the extent that Table 44 requires compliance with 40 C.F.R. § 63.6(e)(1).

d. "Post-Lodging Compliance Dates" shall mean any dates in this Section XIV after the Date of Lodging;

e. "PSD/NNSR Requirements" shall mean the Prevention of Significant Deterioration and Non-Attainment New Source Review requirements found in the following:

   i. 42 U.S.C. § 7475;

   ii. 40 C.F.R. §§ 52.21(a)(2)(iii) and 52.21(j)–52.21(r)(5);

iii. 42 U.S.C. §§ 7502(c)(5), 7503(a)–(c);

iv. 40 C.F.R. Part 51, Appendix S, Part IV, Conditions 1–4;

v. any applicable, federally enforceable state or local regulation that implements, adopts, or incorporates the federal provisions cited in Subparagraphs 123.e.i–iv; and

vi. Title V permit requirement that implements, adopts, or incorporates the federal, or federally enforceable state, provisions cited in Subparagraphs 123.e.i–v;

f. "Requirements Related to Monitoring, Operation, and Maintenance According to Flare Design" shall mean the requirements found in the following regulations:

i. 40 C.F.R. § 60.18(d);

ii. 40 C.F.R. § 63.11(b)(1);

iii. 40 C.F.R. §§ 60.482-10(d), 60.482-10a(d), but only to the extent that these provisions require compliance with 40 C.F.R. § 60.18(d);

iv. 40 C.F.R. §§ 60.482-10(e), 60.482-10a(e), but only to the extent that these provisions relate to flares;

v. 40 C.F.R. §§ 60.592(a), 60.592a(a), but only to the extent that these provisions: *(1)* relate to flares; and *(2)* require compliance with 40 C.F.R. § 60.18(d);

vi. 40 C.F.R. § 63.643(a)(1), but only to the extent that this provision requires compliance with 40 C.F.R. § 63.11(b)(1);

vii. 40 C.F.R. § 63.648(a), but only to the extent that this provision: *(1)* relates to flares; and *(2)* requires compliance with 40 C.F.R. § 60.18(d); and

viii. 40 C.F.R. § 63.1566(a)(1)(i) and Table 15 but only to the extent that this provision: *(1)* relates to flares; and *(2)* requires compliance with 40 C.F.R. § 63.11(b)(1).

g. "Subpart Ja Requirements" shall mean the following requirements of 40 C.F.R. Part 60, Subpart Ja (in effect as of November 13, 2012):

i. H_2S emission limit applicable to flares (set forth in 40 C.F.R. § 60.103a(h));

ii. H_2S monitoring for flares (set forth in 40 C.F.R. § 60.107a(a)(2));

iii. Sulfur monitoring for flares (set forth in 40 C.F.R. § 60.107a(e)); and

iv. Flow monitoring for flares (set forth in 40 C.F.R. § 60.107a(f)) .

124. Entry of this Consent Decree shall resolve the civil claims of the United States for the violations alleged in the Complaint filed in this action through the Date of Lodging.

125. Resolution of Claims for Violating PSD/NNSR Requirements at the Covered Flares. With respect to emissions of H_2S, SO_2, VOCs, and CO from the Covered Flares, entry of this Consent Decree shall resolve the civil claims of the United States against SDP for violations of the PSD/NNSR Requirements resulting from construction or modification from the date of the pre-Lodging construction or modification through: (i) for the SDP Refinery Covered Flares, December 31, 2017; (ii) for the Olefins Flares, December 31, 2017; and (iii) for the HIPA Flare, 24 months after the Date of Entry.

126. Resolution of Pre-Lodging Claims at the Covered Flares for Failing to Comply with: (a) BTU/scf Flared Gas Requirements; (b) General Flare Requirements; (c) Good Air Pollution Control Practice Requirements; and (d) Requirements Related to Monitoring, Operation, and Maintenance According to Flare Design. With respect to emissions of the following pollutants from the Covered Flares, entry of this Consent Decree shall resolve the civil claims of the United States against SDP for violations of the following requirements from the date those claims accrued through the Date of Lodging:

Pollutant(s)	**Requirement/Regulation**
VOCs and HAPs	BTU/scf Flared Gas Requirements
VOCs and HAPs	General Flare Requirements
VOCs and HAPs	Good Air Pollution Control Practice Requirements
VOCs and HAPs	Requirements Related to Monitoring, Operation, and Maintenance According to Flare Design

127. Resolution of Pre-Lodging Claims for Failing to Comply with 40 C.F.R. Part 60, Subpart J.

a. SDP Refinery Covered Flares. With respect to emissions of SO_2 and H_2S from the SDP Refinery Covered Flares, entry of this Consent Decree shall resolve the civil claims of the United States against SDP for violations of 40 C.F.R. Part 60, Subpart J, from the date those claims accrued through the Date of Lodging.

b. SDP Chemical Plant Covered Flares. With respect to emissions of SO_2 and H_2S from the SDP Chemical Plant Covered Flares (as specifically identified in Subparagraphs 127.b.i–iii), entry of this Consent Decree shall resolve the civil claims of the United States against SDP for violations of 40 C.F.R. Part 60, Subpart J, from the date those claims accrued through the Date of Lodging, provided that the claims arose due to one the following:

i. Fuel Gas flowing from the SDP Refinery to the Olefins II and III Flares during emergency situations; or

ii. Gas flowing to the Olefins Flares as a result of refinery streams being processed at the Butane Butylene Hydrotreater Unit; or

iii. Gas redirected from the Girbotol Flare at the SDP Refinery to the A&S and HIPA Flares.

128. Resolution of Claims Continuing Post-Lodging for Failing to Comply with: (a) Requirements Related to Monitoring, Operation, and Maintenance According to Flare Design; and (b) 40 C.F.R. Part 60, Subpart J at Olefins Flares.

a. Requirements Related to Monitoring, Operation, and Maintenance According to Flare Design for all Covered Flares. With respect to emissions of VOCs and HAPs from the Covered Flares, entry of this Consent Decree shall resolve the civil claims of the United States against SDP for the violations set forth in Subparagraph 128.a.i, for the time frame set forth in Subparagraph 128.a.ii:

i. Violations of Requirements Related to Monitoring, Operation, and Maintenance According to Flare Design, but only to the extent that the claims are based on SDP's use of too much steam in relation to Vent Gas flow;

ii. The resolution of liability in Subparagraph 128.a.i extends from the Date of Lodging through, for each Covered Flare, the date in Column C of Appendix 2.1 that is associated with that Covered Flare.

b. 40 C.F.R. Part 60, Subpart J at the Olefins Flares. With respect to emissions of SO_2 and H_2S from the Olefins Flares, entry of this Consent Decree shall resolve the civil claims of the United States against SDP for violations of 40 C.F.R. Part 60, Subpart J, from the Date of Lodging through, for the Olefins Flares, the following dates, for claims that are based on the following circumstances:

i. December 31, 2014, for claims based on Fuel Gas flowing from the SDP Refinery to the Olefins II and III Flares during emergency situations; and

ii. December 31, 2016, for claims based on gas flowing to the Olefins Flares as a result of refinery streams being processed at the Butane Butylene Hydrotreater Unit.

129. Resolution of Claims under Subpart Ja Requirements. Entry of this Consent Decree shall resolve the civil claims of the United States against SDP for violations of the following Subpart Ja Requirements from November 13, 2012, through, for each SDP Refinery Covered Flare, the following:

H_2S Emission Limits (40 C.F.R. § 60.103a(h))	**Sulfur and Flow Monitoring (40 C.F.R. §§ 60.107a(e),(f))**
November 11, 2015	November 11, 2015

130. Resolution of Title V Violations. Entry of this Consent Decree shall resolve the civil claims of the United States against SDP for the violations of Sections 502(a), 503(c), and 504(a) of the CAA, 42 U.S.C. §§ 7661a(a), 7661b(c), 7661c(a), and of 40 C.F.R. §§ 70.1(b), 70.5(a) and (b), 70.6(a) and (c), and 70.7(b), that are based upon the violations resolved by Paragraphs125–129 for the time frames set forth in those Paragraphs.

131. Reservation of Rights: Resolution of Liability in Paragraphs 125 and 128–130 can be Rendered Void. Notwithstanding the resolution of liability in Paragraphs 125 and 128–130 for the period of time between the Date of Lodging and the Post-Lodging Compliance Dates, those resolutions of liability shall be rendered void if SDP materially fails to comply with any of the obligations and requirements of Sections V and VI of this Decree (Compliance Requirements and Emission Credit Generation). However:

a. To the extent that a material failure involves a particular Covered Facility(ies), the resolution of liability shall be rendered void only with respect to claims involving that particular Covered Facility(ies);

b. The resolutions of liability in Paragraphs 125 and 128–130 shall not be rendered void if SDP, as expeditiously as practicable, remedies such material failure and pays all stipulated penalties due as a result of such material failure.

132. The United States reserves all legal and equitable remedies available to enforce the provisions of this Consent Decree, except as expressly stated in Paragraphs 125–130. This Consent Decree shall not be construed to limit the rights of the United States to obtain penalties or injunctive relief under the CAA or implementing regulations, or under other federal or state laws, regulations, or permit conditions, except as expressly specified in Paragraphs 125–130. The United States further reserves all legal and equitable remedies to address any imminent and substantial endangerment to the public health or welfare or the environment arising at, or posed by the Covered Facilities, whether related to the violations addressed in this Consent Decree or otherwise.

133. In any subsequent administrative or judicial proceeding initiated by the United States for injunctive relief, civil penalties, other appropriate relief relating to the Covered Facilities or SDP's CAA violations, SDP shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, claim-splitting, or other defenses based upon any contention that the claims raised by the United States in the subsequent proceeding were or should have been brought in the instant case, except with respect to claims that have been specifically resolved pursuant to Paragraphs 125–130 of this Section and for which the resolution of liability has not been voided pursuant to Paragraph 131.

134. This Consent Decree is not a permit, or a modification of any permit, under any federal, state, or local laws or regulations. SDP is responsible for achieving and maintaining

complete compliance with all applicable federal, state, and local laws, regulations, and permits; and SDP's compliance with this Consent Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as set forth herein. The United States does not, by its consent to the entry of this Consent Decree, warrant or aver in any manner that SDP's compliance with any aspect of this Consent Decree will result in compliance with provisions of the Act, 42 U.S.C. § 7401 *et seq.*, or with any other provisions of federal, state, or local laws, regulations, or permits.

135. This Consent Decree does not limit or affect the rights of SDP or the United States against any third parties that are not party to this Consent Decree, nor does it limit the rights of third parties that are not party to this Consent Decree against SDP, except as otherwise provided by law.

136. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third party not party to this Consent Decree.

XV. COSTS

137. The Parties shall bear their own costs of this action, including attorneys fees, except that the United States shall be entitled to collect the costs (including attorneys fees) incurred in any action necessary to enforce this Consent Decree or to collect any portion of the civil penalty or any stipulated penalties due but not paid by SDP.

XVI. NOTICES

138. Unless otherwise specified herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed to the persons set forth below. Submission by U.S. mail or courier is required and shall be sufficient to comply with the notice requirements of this Consent Decree; however, for

the submission of technical information or data, SDP shall submit the data in electronic form (*e.g.*, a disk or hard drive). The email addresses listed below are to permit the submission of courtesy copies.

Notice or submission to the United States:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
Box 7611 Ben Franklin Station
Washington, DC 20044-7611
Re: DOJ No. 90-5-2-1-09388/1

Notice or submission to EPA:

Director, Air Enforcement Division
Office of Civil Enforcement
U.S. Environmental Protection Agency
Mail Code 2242-A
Regular Mail: 1200 Pennsylvania Ave, N.W.
Ariel Rios Building South
Room 1119
Washington, DC 20460-0001
Express Mail: Use same address but use 20004 as the zip code

and

Associate Director
Air, Toxics, and Inspections Coordination Branch (6 EN-A)
U.S. EPA, Region 6
1445 Ross Avenue
Dallas, Texas 75202

For courtesy purposes, electronic copies to:

parrish.robert@epa.gov
foley.patrick@epa.gov
crawford.dorothy@epa.gov

Notice or submission to SDP:

Kimberly Z. Lesniak
Senior Legal Counsel
Shell Oil Company
One Shell Plaza
910 Louisiana Street
Houston, TX 77002
For courtesy purposes: kim.lesniak@shell.com

Shari Keller
Sr. Staff Environmental Specialist-Air Compliance
Shell Oil Products
Environmental Affairs (OSP 2804B)
910 Louisiana Houston, TX 77002
For courtesy purposes: shari.keller@shell.com

Richard Bourns
Environmental Manager
Shell Deer Park Site
Shell Oil Products Company, LLC
Shell Deer Park, 5900 Highway 225 East,
Deer Park, TX 77536
For courtesy purposes: richard.bourns@shell.com

Any Party may, by written notice to the other Party, change its designated notice recipient(s) or notice address(es) provided above. Notices submitted pursuant to this Section shall be deemed submitted upon mailing, unless otherwise provided in this Consent Decree or by mutual agreement of the Parties in writing.

XVII. EFFECTIVE DATE

139. The Effective Date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court or a motion to enter the Consent Decree is granted, whichever occurs first, as recorded on the Court's docket; provided however, that SDP hereby agrees that it shall be bound to perform duties scheduled to occur prior to the Effective Date. In the event the United States withdraws or withholds consent to this Consent Decree before entry,

or the Court declines to enter this Consent Decree, then the preceding requirement to perform duties scheduled to occur before the Effective Date shall terminate.

XVIII. RETENTION OF JURISDICTION

140. The Court shall retain jurisdiction over this case until termination of this Consent Decree for the purposes of resolving disputes arising under this Decree, entering orders modifying this Decree, or effectuating or enforcing compliance with the terms of this Decree.

XIX. MODIFICATION

141. Except as provided in Paragraph 9, the terms of this Consent Decree may be modified only by a subsequent written agreement signed by the United States and SDP. Where the modification constitutes a material change to any term of this Consent Decree, it shall be effective only upon approval by the Court.

142. Except as provided in Paragraphs 5–9, any disputes concerning modification of this Decree shall be resolved pursuant to Section XII of this Decree (Dispute Resolution); provided, however, that instead of the burden of proof as provided by Paragraph 115, the Party seeking the modification bears the burden of demonstrating that it is entitled to the requested modification in accordance with Federal Rule of Civil Procedure 60(b).

XX. TERMINATION

143. Termination for the SDP Chemical Plant, the SDP Refinery or Entire Consent Decree. If the conditions precedent to termination set forth in Paragraph 144 are satisfied, the requirements of this Consent Decree that are applicable to either the SDP Chemical Plant or the SDP Refinery may be subject to termination or all of the requirements in this Consent Decree may be subject to termination.

144. Termination: Conditions Precedent. Prior to termination, SDP must have completed all of the following requirements of this Consent Decree:

a. Payment of all civil penalties, stipulated penalties and other monetary obligations;

b. Satisfactory compliance with all provisions of Section V of this Decree (Compliance Requirements) with respect to all of the Covered Flaresat the Facility(ies) that is(are) subject to the termination request;

c. Operation for at least one year in satisfactory compliance with the limitations and standards set forth in Paragraphs 41, 40.b, 47.b, 49, 56.b, 56.c, 57.b, 58.c (if and as applicable), 58.d (if and as applicable), and 59 for all of the Covered Flares at the Facility(ies) that is(are) subject to the termination request;

d. Completion of the Mitigation Projects in Section VII;

e. Completion of the Supplemental Environmental Project in Section VIII;

f. Application for and receipt of all non-Title V air permits necessary to ensure survival of the Consent Decree limits and standards after termination of this Consent Decree (the Paragraph 67 requirement) for all of the flares at the Facility(ies) that is(are) subject to the termination request;

g. Application for a modification or amendment to the Title V permit to incorporate the limits and standards in Paragraph 67 into the Title V permit of the Facility(ies) that is(are) subject to the termination request; and

h. Application for such modifications, amendments, or revisions to the Covered Facilities' NPDES permit as may be necessary as a result of the Mitigation Project required in Paragraph 71 of this Consent Decree ("Mitigation Project: North Effluent Treater Controls").

145. Termination: Procedure.

a. At such time as SDP believes that it has satisfied the conditions for termination set forth in Paragraph 144 for either the SDP Chemical Plant or the SDP Refinery or for the entire Consent Decree, SDP may submit a request for termination to the United States by certifying such compliance in accordance with the certification language in Paragraph 89. In the Request for Termination, SDP must demonstrate that it has satisfied the conditions for termination set forth in Paragraph 144. The Request for Termination shall include all necessary supporting documentation.

b. Following receipt by the United States of SDP's Request for Termination, the Parties shall confer informally concerning the Request. If the United States agrees that the Decree may be terminated, the Parties shall submit, for the Court's approval, a joint stipulation terminating the Decree.

c. If the United States does not agree that the Consent Decree may be terminated, or if SDP does not receive a written response from the United States within 60 days of SDP's submission of the Request for Termination, SDP may invoke dispute resolution under Section XII of this Decree (Dispute Resolution).

XXI. PUBLIC PARTICIPATION

146. This Consent Decree shall be lodged with the Court for a period of not less than 30 days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States reserves the right to withdraw or withhold its consent if the comments regarding the Consent Decree disclose facts or considerations indicating that the Consent Decree is inappropriate, improper, or inadequate. SDP consents to entry of this Consent Decree without further notice and agrees not to withdraw from or oppose entry of this Consent Decree by the Court or to

challenge any provision of the Decree unless the United States has notified SDP in writing that it no longer supports entry of the Decree.

XXII. SIGNATORIES/SERVICE

147. Each undersigned representative of SDP and the Assistant Attorney General for the Environment and Natural Resources Division of the Department of Justice (or his or her designee), certify that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

148. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis. SDP agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rules 4 and 5 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXIII. INTEGRATION

149. This Consent Decree and its Appendices constitute the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree and its Appendixes and supersede all prior agreements and understandings, whether oral or written, concerning the settlement embodied herein. No other document, except for any plans or other deliverables that are submitted pursuant to this Decree, nor any representation, inducement, agreement, understanding, or promise, constitutes any part of this Decree or the settlement it represents, and no such extrinsic document or statement of any kind shall be used in construing the terms of this Decree.

XXIV. FINAL JUDGMENT

150. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court in this action as to the United States and SDP. The Court finds that there is no just reason for delay and therefore enters this judgment as a final judgment under Fed. R. Civ. P. 54 and 58.

DATED this ___________ day of ____________________2013.

____
UNITED STATES DISTRICT JUDGE
SOUTHERN DISTRICT OF TEXAS

We hereby consent to the entry of the Consent Decree in the matter of United States, v. Shell Oil Company, et al., subject to public notice and comment.

FOR THE UNITED STATES OF AMERICA

s/ Robert G. Dreher
ROBERT G. DREHER
Acting Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice

s/ Robert D. Parrish
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We hereby consent to the entry of the Consent Decree in the matter of United States v. Shell Oil Company, et al., subject to public notice and comment.

FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

s/ Cynthia Giles***
CYNTHIA GILES
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC

s/ Susan Shinkman***
Susan Shinkman
Director, Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC

s/ Phillip A. Brooks***
PHILLIP A. BROOKS
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC

*** Signed with permission.

We hereby consent to the entry of the Consent Decree in the matter of United States v. Shell Oil Company, et al., subject to public notice and comment.

FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 6

s/ John Blevins***
JOHN BLEVINS
Director
Compliance Assurance and Enforcement Division
EPA Region 6
Dallas, TX

*** Signed with permission.

We hereby consent to the entry of the Consent Decree in the matter United States v. Shell Oil Company, et al.

FOR SHELL OIL COMPANY

By: s/ Barry J. Klein***
BARRY J. KLEIN
General Manager
Deer Park Site
5900 Highway 225 East
Deer Park, TX 77536
Shell Oil Products Company LLC, as Agent for Shell Oil Company

*** Signed with permission.

We hereby consent to the entry of the Consent Decree in the matter of United States v. Shell Oil Company, et al.

FOR DEER PARK REFINING LIMITED PARTNERSHIP

By: s/ Barry J. Klein***
BARRY J. KLEIN
General Manager
Deer Park Site
5900 Highway 225 East
Deer Park, TX 77536
Shell Oil Products Company LLC, as Agent for Shell Oil Company, General Partner

*** Signed with permission.

We hereby consent to the entry of the Consent Decree in the matter of United States v. Shell Oil Company, et al.

FOR SHELL CHEMICAL LP

By: s/ Barry J. Klein***
BARRY J. KLEIN
General Manager
Deer Park Site
5900 Highway 225 East
Deer Park, TX 77536
Shell Oil Products Company LLC, as Agent for Shell Chemical LP

*** Signed with permission.

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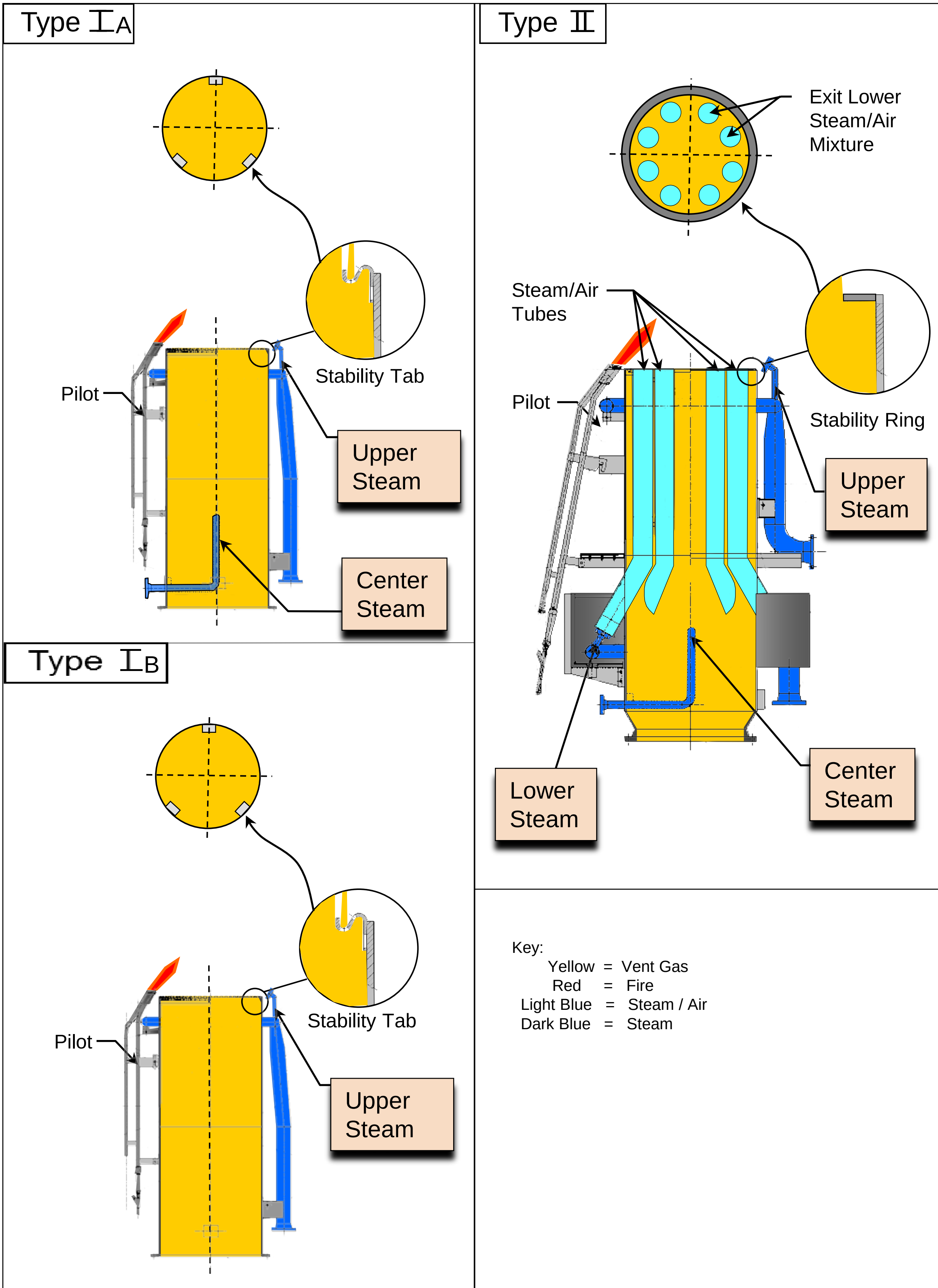
APPENDICES TO CONSENT DECREE

APPENDIX 1.1

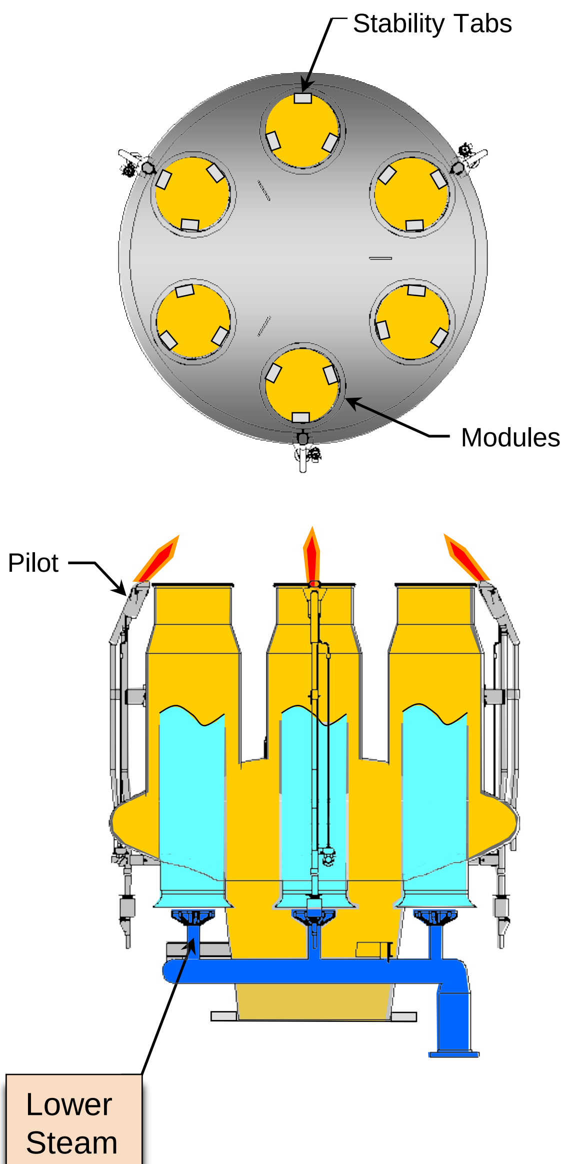
DRAWINGS ILLUSTRATING LOWER, CENTER, AND UPPER STEAM INJECTION IN VARIOUS TYPES OF FLARE TIPS

Appendix 1.1

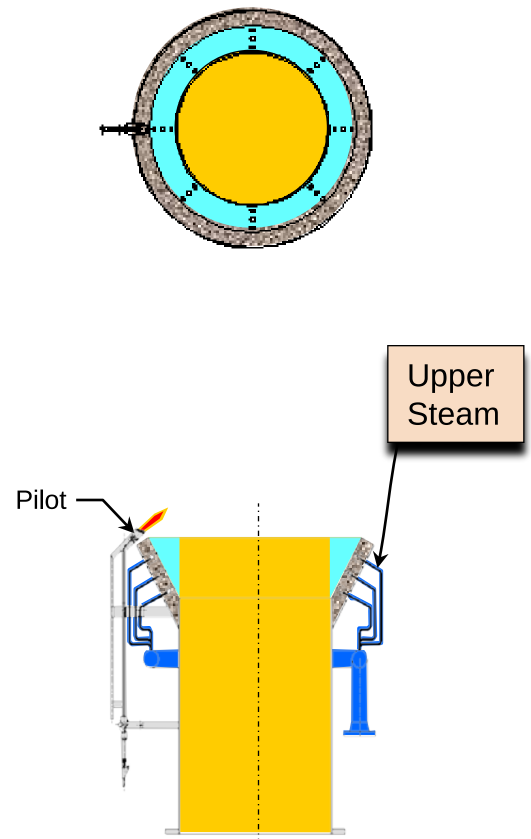

Type IA
Stability Tab
Pilot
Upper Steam
Center Steam
Type IB
Stability Tab
Pilot
Upper Steam
Type II
Exit Lower Steam/Air Mixture
Steam/Air Tubes
Pilot
Stability Ring
Upper Steam
Lower Steam
Center Steam
Key:
Yellow = Vent Gas
Red = Fire
Light Blue = Steam / Air
Dark Blue = Steam

Appendix 1.1

Type III



Type IV



Key:

Yellow = Vent Gas
Red = Fire
Light Blue = Steam / Air
Dark Blue = Steam

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APPENDICES TO CONSENT DECREE

APPENDIX 1.2

GENERAL EQUATIONS

APPENDIX 1.2

GENERAL EQUATIONS

Equation 1: **"*Combustion Efficiency*" or "*CE*":**

$$CE = [CO_2]/([CO_2] + [CO] + [OC])$$

where:

$[CO_2]$ = Concentration in volume percent or ppm-meters of carbon dioxide in the combusted gas immediately above the Combustion Zone

$[CO]$ = Concentration in volume percent or ppm-meters of carbon monoxide in the combusted gas immediately above the Combustion Zone

$[OC]$ = Concentration in volume percent or ppm-meters of the sum of all organic carbon compounds in the combusted gas immediately above the Combustion Zone, counting each carbon molecule separately where the concentration of each individual compound is multiplied by the number of carbon atoms it contains before summing (*e.g.*, 0.1 volume percent ethane shall count as 0.2 percent OC because ethane has two carbon atoms)

For purposes of using the *CE* equation, the unit of measurement for CO_2, CO, and OC must be the same; that is, if "volume percent" is used for one compound, it must be used for all compounds. "Volume percent" cannot be used for one or more compounds and "ppm-meters" for the remainder.

Equation 2: ***"Center Steam Mass Flow Rate" or "$\dot{m}_{s\text{-}cen}$":***

$$\dot{m}_{s\text{-}cen} = Q_{s\text{-}cen} \times (18/385.5)$$

where:

$Q_{s\text{-}cen}$ = Center Steam Volumetric Flow Rate

Equation 3: ***"Total Steam Mass Flow Rate" or "$\dot{m}_s$":***

$$\dot{m}_s = Q_s \times (18/385.5)$$

where:

Q_s = Total Steam Volumetric Flow Rate

APPENDIX 1.2

Equation 4: ***"Vent Gas Mass Flow Rate"*** **or "$\dot{m}_{vg}$":**

$$\dot{m}_{vg} = Q_{vg} \times (MW_{vg}/385.5)$$

where:

Q_{vg} = Vent Gas Volumetric Flow Rate

MW_{vg} = Molecular Weight, in pounds per pound-mole, of the Vent Gas, as measured by the Vent Gas Average Molecular Weight Analyzer described in Paragraph 19 of this Consent Decree

[End of Appendix 1.2]

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APPENDICES TO CONSENT DECREE

APPENDIX 1.3

CALCULATING $NHV_{CZ\text{-}LIMIT}$ AND NHV_{CZ} FOR STREAM-ASSISTED FLARES

APPENDIX 1.3

CALCULATING $NHV_{cz\text{-}limit}$ AND NHV_{cz} FOR STEAM-ASSISTED FLARES

All abbreviations, constants, and variables are defined in the Key on Page 6 of this Appendix.

Steps in the Calculations

Step 1: Determine the Lower Flammability Limit ("LFL") of Each Individual Vent Gas Compound

Take the LFL values of each individual Vent Gas compound from Table 1 in this Appendix.

Step 2: Calculate the LFL of the vent gas mixture

The average lower flammability limit of the vent gas is calculated by Le Chatelier's equation shown below as Equation 1. This calculation uses the weighted average of the LFLs of the individual compounds weighted by their volume fraction of the vent gas. All inerts, including nitrogen, are assumed to have an infinite lower flammability limit (e.g. $LFL_{N2} = \infty$).

$$LFL_{vg} = \frac{1}{\sum_{i=1}^{n}\left(\frac{x_i}{LFL_i}\right)} \qquad \textit{Equation 1}$$

Step 3: Determine the Net Heating Value of the Vent Gas (NHV_{vg})

If a Gas Chromatograph is used: The net heating value of the vent gas is calculated and reported from the GC at the conclusion of each analytical cycle (~10-15 minutes). Equation 2 is used by the GC to calculate the vent gas net heating value from each individual compound net heating value. Individual compound volume fractions, except for water, are measured directly by the GC. A company is not required to measure water in Vent Gas. If a company chooses to measure water, then: (i) if the water measurement is taken upstream of a knock-out drum, then water does not have to be included in the calculation of NHV_{vg}; (ii) if no knock-out drum exists or if the water measurement is taken after the knock-out drum, then the company must include water in the calculation of NHV_{vg} and adjust the concentration of the compounds measured by the GC to a wet basis. Individual compound net heating values, including water, are listed in Table 1 of this Appendix.

$$NHV_{vg} = \sum_{i=1}^{n}(x_i \cdot NHV_i) \qquad \textit{Equation 2}$$

If a Net Heating Value Analyzer/Calculator is used: Use the measured value.

NOTE: Table 1 includes two alternative values for the Net Heating Value of hydrogen: the actual NHV of hydrogen (274 BTU/scf) and an "adjusted" NHV of hydrogen (1212 BTU/scf).

APPENDIX 1.3

Companies have the option of using either in calculating NHV_{vg}; however, whichever option is selected also must be used in calculating NHV_{cz}.

Step 4: Calculate the NHV_{vg} at its LFL ($NHV_{vg\text{-}LFL}$)

Using LFL_{vg} from Equation 1 and NHV_{vg} from Equation 2, the $NHV_{vg\text{-}LFL}$ is calculated by Equation 3.

$$NHV_{vg-LFL} = NHV_{vg} \cdot LFL_{vg} \qquad \textbf{\textit{Equation 3}}$$

Step 5: Multiply $NHV_{vg\text{-}LFL}$ by the Combustion Efficiency Multipliers to calculate the *$NHV_{cz\text{-}limit}$*

The Net Heating Value of the Gases in the Combustion Zone (NHV_{cz}) of a Flare that is needed to ensure an acceptable Combustion Efficiency is determined by multiplying $NHV_{vg\text{-}LFL}$ by Combustion Efficiency Multipliers appropriate to the flare category and the volume percent of hydrogen in the Vent Gas as defined in Table 2.

The Net Heating Value of Combustion Zone Gas Limit is calculated as follows:

$$NHV_{cz-limit} = \left(A + B \cdot x_{propylene}\right) \cdot NHV_{vg-LFL} \qquad \textbf{\textit{Equation 4}}$$

Step 6: Calculate the Net Heating Value of the Combustion Zone Gas (NHV_{cz})

The NHV in the combustion zone (NHV_{cz}) combines the NHVs of the Vent Gas, pilot gas, and steam and is calculated by Equation 5a (based on mass flow measurement) or 5b (based on volumetric flow measurement). These two equations are equivalent for combustion zone conditions, as shown in Addendum A to this Appendix. The NHV of steam is assumed to be zero. Vent Gas flow rate ($\dot{m}_{vg}$ *or* Q_{vg}) and steam flow rate ($\dot{m}_s$ *or* Q_s) are measured by on-line flow meters. The pilot gas flow rate ($\dot{m}_{pg}$ *or* Q_{pg}) is constant for each flare and set by an orifice.

$$NHV_{cz} = \frac{\left(\frac{\dot{m}_{vg} \cdot NHV_{vg}}{MW_{vg}}\right) + \left(\frac{\dot{m}_{pg} \cdot NHV_{pg}}{MW_{pg}}\right)}{\left(\frac{\dot{m}_{vg}}{MW_{vg}}\right) + \left(\frac{\dot{m}_{pg}}{MW_{pg}}\right) + \left(\frac{\dot{m}_{s}}{MW_{H_2O}}\right) + \left(\frac{\dot{m}_{air}}{MW_{air}}\right)} \qquad \textbf{\textit{Equation 5a}}$$

OR

$$NHV_{cz} = \frac{\left(Q_{vg} * NHV_{vg}\right) + \left(Q_{pg} * NHV_{pg}\right)}{Q_{vg} + Q_{pg} + Q_s + Q_{air}} \qquad \textbf{\textit{Equation 5b}}$$

APPENDIX 1.3

The values for $\dot{m}_s$, $\dot{m}_{air}$, Q_s and Q_{air} are determined as follows based on the type of flare:

Steam-Assisted Flare without a Minimum Steam Reduction System ("MSRS")

$\dot{m}_s \ or \ Q_s = measured \ value$

$\dot{m}_{air} \ or \ Q_{air} = 0$

Steam-Assisted Flare with MSRS

$\dot{m}_s \ or \ Q_s = measured \ value$

$\dot{m}_{air} \ or \ Q_{air} = result \ from \ Equation \ 13 \ in \ Step \ 6a$

OR

$\dot{m}_{air} \ or \ Q_{air} = 0$ *with vendor certification that the MSRS equipment installed on the flare is not capable (even at minimum vent gas flow) of inspirating more than twice the stoichiometric volume of air into the vent gas.*

The molecular weight of the vent gas (MW_{vg}) is calculated by the GC using Equation 6. An on-line ultrasonic flow meter may also be used to calculate MW_{vg}. Individual compound molecular weights are listed in Table 1 of this Appendix.

$$MW_{vg} = \sum_{i=1}^{n} (x_i \cdot MW_i) \qquad \textbf{\textit{Equation 6}}$$

The NHV of the pilot gas (NHV_{pg}) and MW of the pilot gas (MW_{pg}) are calculated using Equations 7 and 8, respectively. These calculations are similar to the vent gas calculations, except the individual compound volume fractions are that of the pilot gas and not the vent gas. Individual compound volume fractions are measured by laboratory analysis of a pilot gas sample, or may be taken from the natural gas supplier's laboratory certificate of analysis.

$$NHV_{pg} = \sum_{i=1}^{n} (pg_i \cdot NHV_i) \qquad \textbf{\textit{Equation 7}}$$

$$MW_{pg} = \sum_{i=1}^{n} (pg_i \cdot MW_i) \qquad \textbf{\textit{Equation 8}}$$

APPENDIX 1.3

Step 6a: Calculation of air mass flow rate for flares equipped with MSRS.

The complete combustion of an organic compound comprised of a combination of carbon and hydrogen atoms is shown in Equation 9:

$$C_xH_y + \left(x + \frac{y}{4}\right) O_2 \rightarrow xCO_2 + \left(\frac{y}{2}\right) H_2O$$ ***Equation 9***

Note: *x* and *y* values for each compound are found in Table 1 of this Appendix.

Therefore, the stoichiometric oxygen molar flow rate (moles/hr) for any given combustible compound flow is defined by Equation 10a (mass basis) or Equation 10b (volumetric basis):

$$n_{O2-stoich} = x_j \left(\frac{\dot{m}_{vg}}{MW_{vg}}\right)\left(x + \frac{y}{4}\right)$$ ***Equation 10a***

OR

$$\dot{n}_{O2-stoich} = x_j \left(\frac{Q_{vg}}{385.5}\right)\left(x + \frac{y}{4}\right)$$ ***Equation 10b***

The stoichiometric oxygen mass flow rate for the vent gas (lb/hr) or stoichiometric oxygen volumetric flow rate for the vent gas (scfh) is given by Equation 11a (mass basis) or 11b (volumetric basis).

$$m_{O2-stoich-vg} = MW_{O_2} * \sum_{j=1}^{n} n_{O2-stoich_j}$$ ***Equation 11a***

OR

$$Q_{O2-stoich-vg} = 385.5 * \sum_{j=1}^{n} n_{O2-stoich_j}$$ ***Equation 11b***

The stoichiometric air mass flow rate (lb/hr) or stoichiometric air volumetric flow rate (scfh) for the vent gas is given by Equation 12a (mass basis) or Equation 12b (volumetric basis).

$$\dot{m}_{air-stoich-vg} = \frac{MW_{air}}{0.21 \cdot MW_{O_2}} * \dot{m}_{O2-stoich-vg}$$ ***Equation 12a***

OR

$$Q_{air-stoich-vg} = \frac{Q_{O2-stoich-vg}}{0.21}$$ ***Equation 12b***

APPENDIX 1.3

The air mass flow (lb/hour) or air volumetric flow (scfh) used in Equation 5a or 5b is given by subtracting two times the stoichiometric air from the total air provided by the MSRS. This is shown in Equation 13a and 13.b.

$$\dot{m}_{air} = \dot{m}_{air-MSRS} - (2 * \dot{m}_{air-stoich-vg}) \qquad \textit{Equation 13a}$$

OR

$$Q_{air} = Q_{air-MSRS} - (2 * Q_{air-stoich-vg}) \qquad \textit{Equation 13b}$$

The equation for $\dot{m}_{air-MSRS}$ or $Q_{air-MSRS}$ is specific to the MSRS installed and must be provided by the MSRS vendor. The factor of 2 used in Equation 13 is based on the best information available as of the Date of Lodging. If new information becomes available thereafter, the parties may modify that factor; any such modification does not constitute a material modification to the Consent Decree.

If $\dot{m}_{air} < 0$ then $\dot{m}_{air} = 0$
OR
If $Q_{air} < 0 \; then \; Q_{air} = 0$

Step 7: Ensure that during flare operation, $NHV_{cz} \geq NHV_{cz\text{-}limit}$

The flare must be operated to ensure that NHV_{cz} is equal to or above $NHV_{cz\text{-}limit}$ to ensure acceptable combustion efficiency. Equation 14 shows this relationship.

$$NHV_{cz} \geq NHV_{cz-limit} \qquad \textit{Equation 14}$$

APPENDIX 1.3

Key to the Abbreviations:

$0.21 = mole\ fraction\ of\ oxygen\ in\ air (0.21\ lb\text{–}mol\ O_2/lb\text{–}mol\ air)$
$385.5 = conversion\ from\ pound\ moles\ to\ standard\ cubic\ feet\ (385.5\ scf/lb\text{-}mol)$
$A = overall\ combustion\ efficiency\ multiplier\ for\ NHV_{vg-LFL}\ (unitless)$
$B = propylene\ combustion\ efficiency\ multiplier\ for\ NHV_{vg-LFL}\ (unitless)$
$C_{vg} = concentration\ of\ VOC\ in\ the\ vent\ gas\ (vol\ \%)$
$i = individual\ numbered\ compound\ from\ column\ i\ in\ Table\ 1\ (unitless)$
$j = individual\ numbered\ compound\ from\ column\ j\ in\ Table\ 1\ (unitless)$
$k = individual\ gaseous\ component\ of\ the\ combustion\ zone\ (unitless)$
$LFL_i = lower\ flammability\ limit\ of\ individual\ compound\ (vol\ \%)$
$LFL_{vg} = lower\ flammability\ limit\ of\ vent\ gas\ (vol\ \%)$
$\dot{m}_{air} = mass\ flow\ rate\ of\ air\ (lb/hr)$
$\dot{m}_{air-MSRS} = total\ mass\ flow\ rate\ of\ air\ introduced\ by\ an\ MSRS\ (lb/hr)$
$\dot{m}_{air-stoich-vg} = stoichiometric\ air\ mass\ flow\ for\ the\ vent\ gas (lb/hr)$
$\dot{m}_k = mass\ flow\ rate\ of\ individual\ combustion\ zone\ gas\ component\ (lb/hr)$
$\dot{m}_{O2-stoich-vg} = stoichiometric\ oxygen\ mass\ flow\ for\ the\ vent\ gas\ (lb/hr)$
$\dot{m}_{pg} = mass\ flow\ rate\ of\ pilot\ gas\ (lb/hr)$
$\dot{m}_s = mass\ flow\ rate\ of\ total\ steam\ (lb/hr)$
$\dot{m}_{vg} = mass\ flow\ rate\ of\ vent\ gas\ (lb/hr)$
$\dot{n}_{O2-stoich} = stoichiometric\ oxygen\ molar\ flow\ for\ an\ individual\ compound\ (mol/hr)$
$MW_{H_2O} = molecular\ weight\ of\ water\ (18.02\ lb/lb\text{–}mol)$
$MW_i = molecular\ weight\ of\ individual\ compound\ (lb/lb\text{–}mol)$
$MW_k = molecular\ weight\ of\ individual\ combustion\ zone\ gas\ component (lb/lb\text{–}mol)$
$MW_{O_2} = molecular\ weight\ of\ oxygen\ (32.0\ lb/lb\text{–}mol)$
$MW_{air} = molecular\ weight\ of\ air\ (28.9\ lb/lb\text{–}mol)$
$MW_{pg} = molecular\ weight\ of\ pilot\ gas\ (lb/lb\text{–}mol)$
$MW_{vg} = molecular\ weight\ of\ vent\ gas\ (lb/lb\text{–}mol)$
$n = list\ of\ individual\ compounds\ from\ Table\ 1\ (unitless)$
$NHV_{cz} = net\ heating\ value\ of\ the\ combustion\ zone\ (BTU/scf)$
$NHV_i = net\ heating\ value\ of\ individual\ compound\ (BTU/scf)$
$NHV_{vg-LFL} = net\ heating\ value\ vent\ gas\ at\ lower\ flammability\ limit\ (BTU/scf)$
$NHV_{cz-limit} = limit\ net\ heating\ value\ of\ the\ combustion\ zone\ (BTU/scf)$
$NHV_{pg} = net\ heating\ value\ of\ pilot\ gas\ (BTU/scf)$
$NHV_{vg} = net\ heating\ value\ of\ vent\ gas\ (BTU/scf)$
$P_{cz} = pressure\ of\ combustion\ zone\ gas\ (psia)$
$P_{std} = ambient\ pressure\ at\ standard\ condtions\ (14.696\ psi)$
$pg_i = individual\ compound\ volume\ fraction\ in\ pilot\ gas\ (vol\ fraction)$
$Q_{air-MSRS} = total\ volumetric\ flow\ rate\ of\ air\ introduced\ by\ an\ MSRS\ (scfh)$
$Q_{air-stoich-vg} = stoichiometric\ air\ volumetric\ flow\ for\ the\ vent\ gas\ (scfh)$
$Q_k = individal\ vent\ gas\ component\ volumetric\ flow\ rate\ (scfh)$
$Q_{k,acf} = individal\ vent\ gas\ component\ volumetric\ flow\ rate\ (ft^3/hr)$
$Q_{O2-stoich-vg} = stoichiometric\ oxygen\ volumetric\ flow\ for\ the\ vent\ gas\ (scfh)$
$Q_{vg} = vent\ gas\ volumetric\ flow\ rate\ (scfh)$
$Q_{pg} = pilot\ gas\ volumetric\ flow\ rate\ (scfh)$
$Q_s = steam\ volumetric\ flow\ rate\ (scfh)$
$Q_{air} = air\ volumetric\ flow\ rate\ (scfh)$
$R = gas\ constant\ (10.73\ ft^3 \cdot psi/lb - mol \cdot R)$
$T_{cz} = absolute\ temperature\ of\ combustion\ zone\ gas\ (°R)$
$T_{std} = absolute\ temperature\ at\ standard\ conditions (528°R)$
$x = moles\ of\ carbon\ per\ mole\ of\ C_xH_y\ (mol/mol)$
$x_i = individual\ compound\ volume\ fraction\ in\ the\ vent\ gas\ (vol\ fraction)$
$x_j = individual\ combustible\ compound\ volume\ fraction\ in\ the\ vent\ gas\ (vol\ fraction)$
$x_{propylene} = volume\ fraction\ of\ propylene\ in\ the\ vent\ gas\ (vol\ fraction)$
$y = moles\ of\ hydrogen\ per\ mole\ of\ C_xH_y\ (mol/mol)$

APPENDIX 1.3

Table 1
Individual Compound Properties

$i^{(1)}$	j	Compound	NHV_i (Btu/scf)	MW_i (lb/lbmol)	LFL_i (vol fraction)	C_x	H_y
1	1	Hydrogen	274 or 1212[(2)]	2.02	0.040	0	2
2	-	Oxygen	0	32.00	∞	n/a	n/a
3	-	Nitrogen	0	28.01	∞	n/a	n/a
4	-	CO_2	0	44.01	∞	n/a	n/a
5	-	CO	316	28.01	0.125	n/a	n/a
6	2	Methane	896	16.04	0.050	1	4
7	3	Ethane	1595	30.07	0.030	2	6
8	4	Ethylene	1477	28.05	0.027	2	4
9	5	Acetylene	1404	26.04	0.025	2	2
10	6	Propane	2281	44.10	0.021	3	8
11	7	Propylene	2150	42.08	0.024	3	6
12	8	iso-Butane	2957	58.12	0.018	4	10
13	9	n-Butane	2968	58.12	0.018	4	10
14	10	iso-Butene	2928	56.11	0.018	4	8
15	11	trans-Butene	2826	56.11	0.017	4	8
16	12	cis-Butene	2830	56.11	0.016	4	8
17	13	1,3-Butadiene	2690	54.09	0.020	4	6
18	14	Pentane+ (C_5+)	3655	72.15	0.014	5	12
19	-	Water[(3)]	0	18.02	∞	n/a	n/a

[1] i=all compounds, j=organic compounds and hydrogen

[2] If using an H_2-adjusted NHV_{vg} and NHV_{cz}, then use 1212 BTU/scf for hydrogen.

[3] A GC does not measure water. If water is measured by means of another instrument, the properties of water listed in this row shall be used.

Note: Benzene is not required to be speciated by the Gas Chromatograph for this refinery settlement (*see* Appendix 1.9) because benzene is present in the Vent Gas only in *de minimis* quantities. Because benzene speciation is not required, it is not listed in Table 1of this Appendix. The Vent Gas composition involved in other future settlements should be evaluated on a case-by-case basis to determine if benzene speciation should be required.

APPENDIX 1.3

Table 2
Combustion Efficiency Multipliers for Steam-Assisted Flares:
Variables Based on Minimum Steam Requirements
and VOC Concentration in the Vent Gas

Minimum Steam	VOC Vent Gas Concentration	A Multiplier	B Multiplier*	
			Condition X	Condition Y
≤ 1000 lb/hr	≤ 20.0%	6.45	4.0	0.0
≤ 1000 lb/hr	> 20.0%	6.85	4.0	0.0
> 1000 lb/hr	≤ 20.0%	7.1	4.0	0.0
> 1000 lb/hr	> 20.0%	7.4	4.0	0.0

*The B Multiplier used depends on the relationship of hydrogen and propylene in the vent gas as follows:
Condition X: $3 \leq H_2\% \leq 8$ and Propylene% $\geq H_2\%$ (all percentages are volume or mole percentages)
Condition Y: Any condition not meeting the requirements for Condition X.

Note: The specifications for Condition X are based on the best information available as of the Date of Lodging. If new information becomes available thereafter, the parties may modify these conditions; any such modification does not constitute a material modification to the Consent Decree.

The "VOC Vent Gas Concentration" shall be calculated on an annual average basis as follows:

$$C_{vg} = \sum_{j=4}^{n} x_j * 100 \qquad \textbf{\textit{Equation 15}}$$

Note: The summation does not include methane or ethane.

APPENDIX 1.3

Addendum A
Verification of Equation 5a and Equation 5b Equivalency

In this Appendix, all gaseous flows (i.e, vent gas, steam, pilot gas, and air) may be measured on either a mass basis (lb/hr) or a volumetric basis (scfh). Depending on which measurement methodology is used, different versions of some equations must be used. These versions are designated with an "a" or "b" (e.g. Equation 5a or 5b). In all cases, these equations are equivalent. This Addendum demonstrates the equivalence of the two methods for calculating NHVcz.

Equation 5b uses volumetric flow rates for the calculation of NHV_{cz}:

$$NHV_{cz} = \frac{(Q_{vg} * NHV_{vg}) + (Q_{pg} * NHV_{pg})}{Q_{vg} + Q_{pg} + Q_s + Q_{air}} \qquad \textbf{\textit{Equation 5b}}$$

The ideal gas law provides a method for determining volumetric flow rate of a specific gas, *k,* in the combustion zone at standard conditions:

$$Q_k = Q_{k,acf} * \frac{P_{cz}}{P_{std}} * \frac{T_{std}}{T_{cz}} \qquad \textbf{\textit{Equation A1}}$$

$$Q_{k,acf} = \frac{\dot{m}_k R T_{cz}}{MW_k P_{cz}} \qquad \textbf{\textit{Equation A2}}$$

$$Q_k = \frac{\dot{m}_k R T_{cz}}{MW_k P_{cz}} * \frac{P_{cz}}{P_{std}} * \frac{T_{std}}{T_{cz}} = \frac{\dot{m}_k R T_{std}}{MW_k P_{std}} \qquad \textbf{\textit{Equation A3}}$$

$$Q_k = \frac{\dot{m}_k * 10.73 * 528}{MW_k * 14.696} = 385.5 \frac{\dot{m}_k}{MW_k} \qquad \textbf{\textit{Equation A4}}$$

Substitution of this expression into Equation 5b gives NHV_{cz} in terms of mass flow:

$$NHV_{cz} = \frac{\left(385.5 \frac{\dot{m}_{vg}}{MW_{vg}} * NHV_{vg}\right) + \left(385.5 \frac{\dot{m}_{pg}}{MW_{pg}} * NHV_{pg}\right)}{385.5 \frac{\dot{m}_{vg}}{MW_{vg}} + 385.5 \frac{\dot{m}_{pg}}{MW_{pg}} + 385.5 \frac{\dot{m}_s}{MW_{H_2O}} + 385.5 \frac{\dot{m}_{air}}{MW_{air}}} \qquad \textbf{\textit{Equation A5}}$$

Because the combustion zone is well-mixed, each gaseous component of the combustion zone is at the same temperature and pressure. Thus, the last expression reduces to Equation 5a:

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$$NHV_{cz} = \frac{\left(\frac{\dot{m}_{vg} \cdot NHV_{vg}}{MW_{vg}}\right) + \left(\frac{\dot{m}_{pg} \cdot NHV_{pg}}{MW_{pg}}\right)}{\left(\frac{\dot{m}_{vg}}{MW_{vg}}\right) + \left(\frac{\dot{m}_{pg}}{MW_{pg}}\right) + \left(\frac{\dot{m}_{s}}{MW_{H_2O}}\right) + \left(\frac{\dot{m}_{air}}{MW_{air}}\right)} \qquad \textbf{\textit{Equation 5a}}$$

This demonstrates the equivalence of Equations 5a and 5b.

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APPENDIX 1.4

EPA'S POLICY ON EXCESS EMISSIONS DURING MALFUNCTIONS, STARTUP, AND SHUTDOWN

APPENDIX 1.4

POLICY ON EXCESS EMISSIONS DURING MALFUNCTIONS, STARTUP, AND SHUTDOWN

Introduction

This policy specifies when and in what manner state implementation plans (SIPs) may provide for defenses to violations caused by periods of excess emissions due to malfunctions,[1] startup, or shutdown. Generally, since SIPs must provide for attainment and maintenance of the national ambient air quality standards and the achievement of PSD increments, all periods of excess emissions must be considered violations. Accordingly, any provision that allows for an automatic exemption[2] for excess emissions is prohibited.

However, the imposition of a penalty for excess emissions during malfunctions caused by circumstances entirely beyond the control of the owner or operator may not be appropriate. States may, therefore, as an exercise of their inherent enforcement discretion, choose not to penalize a source that has produced excess emissions under such circumstances.

This policy provides an alternative approach to enforcement discretion for areas and pollutants where the respective contributions of individual sources to pollutant concentrations in ambient air are such that no single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, as is often the case for sulfur dioxide and lead,[3] EPA believes approaches other than enforcement discretion are not appropriate. In such cases, any excess emissions may have a significant chance of causing an exceedance or violation of the applicable standard or PSD increment.

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[1]The term <u>excess emission</u> means an air emission level which exceeds any applicable emission limitation. <u>Malfunction</u> means a sudden and unavoidable breakdown of process or control equipment.

[2]The term <u>automatic exemption</u> means a generally applicable provision in a SIP that would provide that if certain conditions existed during a period of excess emissions, then those exceedances would not be considered violations.

[3]This policy also does not apply for purposes of PM2.5 NAAQS. In American Trucking Association v. EPA, 175 F. 3d 1027 (D.C. Circ., 1999), the court remanded the PM2.5 NAAQS to the EPA. The Agency has not determined whether this policy is appropriate for PM2.5 NAAQS.

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Except where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, states may include in their SIPs affirmative defenses[4] for excess emissions, as long as the SIP establishes limitations consistent with those set out below. If approved into a SIP, an affirmative defense would be available to sources in an enforcement action seeking penalties brought by the state, EPA, or citizens. However, a determination by the state not to take an enforcement action would not bar EPA or citizen action.[5]

In addition, in certain limited circumstances, it may be appropriate for the State to build into a source-specific or source-category-specific emission standard a provision stating that the otherwise applicable emission limitations do not apply during narrowly defined startup and shutdown periods.

I. AUTOMATIC EXEMPTIONS AND ENFORCEMENT DISCRETION

If a SIP contains a provision addressing excess emissions, it cannot be the type that provides for automatic exemptions. Automatic exemptions might aggravate ambient air quality by excusing excess emissions that cause or contribute to a violation of an ambient air quality standard. Additional grounds for disapproving a SIP that includes the automatic exemption approach are discussed in more detail at 42 Fed. Reg. 58171 (November 8, 1977) and 42 Fed. Reg. 21372 (April 27, 1977). As a result, EPA will not approve any SIP revisions that provide automatic exemptions for periods of excess emissions.

The best assurance that excess emissions will not interfere with NAAQS attainment, maintenance, or increments is to address excess emissions through enforcement discretion. This policy provides alternative means for addressing excess emissions of criteria pollutants. However, this policy does not apply where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Moreover,

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[4]The term affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

[5]Because all periods of excess emissions are violations and because affirmative defense provisions may not apply in actions for injunctive relief, under no circumstances would EPA consider periods of excess emissions, even if covered by an affirmative defense, to be "federally permitted releases" under EPCRA or CERCLA.

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nothing in this guidance should be construed as requiring States to include affirmative defense provisions in their SIPs.

II. AFFIRMATIVE DEFENSES FOR MALFUNCTIONS

The EPA can approve a SIP revision that creates an affirmative defense to claims for penalties in enforcement actions regarding excess emissions caused by malfunctions as long as the defense does not apply to SIP provisions that derive from federally promulgated performance standards or emission limits, such as new source performance standards (NSPS) and national emissions standards for hazardous air pollutants (NESHAPS).[6] In addition, affirmative defenses are not appropriate for areas and pollutants where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments. Furthermore, affirmative defenses to claims for injunctive relief are not allowed. To be approved, an affirmative defense provision must provide that the defendant has the burden of proof of demonstrating that:

1. The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator;

2. The excess emissions (a) did not stem from any activity or event that could have been foreseen and avoided, or planned for, and (b) could not have been avoided by better operation and maintenance practices;

3. To the maximum extent practicable the air pollution control equipment or processes were maintained and operated in a manner consistent with good practice for minimizing emissions;

4. Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded. Off-shift labor and overtime must have been utilized, to the extent practicable, to ensure that such repairs were made as expeditiously as practicable;

5. The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

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[6]To the extent a State includes NSPS or NESHAPS in its SIP, the standards should not deviate from those that were federally promulgated. Because EPA set these standards taking into account technological limitations, additional exemptions would be inappropriate.

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6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence;

9. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

10. The owner or operator properly and promptly notified the appropriate regulatory authority.

The EPA interprets these criteria narrowly. Only those malfunctions that are sudden, unavoidable, and unpredictable in nature qualify for the defense. For example, a single instance of a burst pipe that meets the above criteria may qualify under an affirmative defense. The defense would not be available, however, if the facility had a history of similar failures because of improper design, improper maintenance, or poor operating practices. Furthermore, a source must have taken all available measures to compensate for and resolve the malfunction. If a facility has a baghouse fire that leads to excess emissions, the affirmative defense would be appropriate only for the period of time necessary to modify or curtail operations to come into compliance. The fire should not be used to excuse excess emissions generated during an extended period of time while the operator orders and installs new bags, and relevant SIP language must limit applicability of the affirmative defense accordingly.

III. EXCESS EMISSIONS DURING STARTUP AND SHUTDOWN

In general, startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

A. SOURCE CATEGORY SPECIFIC RULES FOR STARTUP AND SHUTDOWN

For some source categories, given the types of control technologies available, there may exist short periods of emissions during startup and shutdown when, despite best efforts regarding planning, design, and operating procedures, the

APPENDIX 1.4

otherwise applicable emission limitation cannot be met. Accordingly, except in the case where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, it may be appropriate, in consultation with EPA, to create narrowly-tailored SIP revisions that take these technological limitations into account and state that the otherwise applicable emissions limitations do not apply during narrowly defined startup and shutdown periods. To be approved, these revisions should meet the following requirements:

1. The revision must be limited to specific, narrowly-defined source categories using specific control strategies (e.g., cogeneration facilities burning natural gas and using selective catalytic reduction);

2. Use of the control strategy for this source category must be technically infeasible during startup or shutdown periods;

3. The frequency and duration of operation in startup or shutdown mode must be minimized to the maximum extent practicable;

4. As part of its justification of the SIP revision, the state should analyze the potential worst-case emissions that could occur during startup and shutdown;

5. All possible steps must be taken to minimize the impact of emissions during startup and shutdown on ambient air quality;

6. At all times, the facility must be operated in a manner consistent with good practice for minimizing emissions, and the source must have used best efforts regarding planning, design, and operating procedures to meet the otherwise applicable emission limitation; and

7. The owner or operator's actions during startup and shutdown periods must be documented by properly signed, contemporaneous operating logs, or other relevant evidence.

B. GENERAL AFFIRMATIVE DEFENSE PROVISIONS RELATING TO STARTUP AND SHUTDOWN

In addition to the approach outlined in Section II(A) above, States may address the problem of excess emissions occurring during startup and shutdown periods through an enforcement discretion approach. Further, except in the case where a single source or small group of sources has the potential to cause an exceedance of the NAAQS or PSD increments, States may also adopt for their SIPs an affirmative defense approach. Using this

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approach, all periods of excess emissions arising during startup and shutdown must be treated as violations, and the affirmative defense provision must not be available for claims for injunctive relief. Furthermore, to be approved, such a provision must provide that the defendant has the burden of proof of demonstrating that:

1. The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

2. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

3. If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

4. At all times, the facility was operated in a manner consistent with good practice for minimizing emissions;

5. The frequency and duration of operation in startup or shutdown mode was minimized to the maximum extent practicable;

6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and

9. The owner or operator properly and promptly notified the appropriate regulatory authority.

If excess emissions occur during routine startup or shutdown periods due to a malfunction, then those instances should be treated as other malfunctions that are subject to the malfunction provisions of this policy. (Reference Part I above).

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APPENDIX 1.5

CALCULATING MOMENTUM FLUX RATIO

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CALCULATING MOMENTUM FLUX RATIO

Momentum Flux Ratio (MFR) is the relationship between the density (ρ) and velocity (v) of the Vent Gas plus Center Steam to the density and velocity of the wind. It is defined in Equation 1.

$$MFR = \frac{\rho_{vg+s,cent} \cdot v_{vg+s,cent}{}^2}{\rho_{air} \cdot v_{air}{}^2} \qquad \textbf{\textit{Equation 1}}$$

The numerator of the fraction is the "momentum flux" of the Vent Gas plus Center Steam and the denominator is the "momentum flux" of the air (wind). As the velocity of the wind increases, the MFR will decline for a given Vent Gas composition and flow rate.

Calculations for the density (ρ) components and velocity (v) components are discussed separately below.

Calculating Density

The general formula to calculate the density of any given component (ρ_i) at standard temperature and pressure (68 °F, 1 atm) is shown in Equation 2.

$$\rho_i = \frac{MW_i \cdot P}{R \cdot T_{abs}} = \frac{MW_i \cdot 14.696\, psi}{10.73 \frac{psi \cdot ft^3}{lbmol \cdot °R} \cdot (460°R + 68°R)} = \frac{MW_i}{385.5} \qquad \textbf{\textit{Equation 2}}$$

From the final form of Equation 2, the density of Ambient Air (ρ_{air}), Vent Gas (ρ_{vg}), and Center Steam ($\rho_{s,cent}$) can be calculated, shown in Equations 3, 4, and 5.

$$\rho_{air} = \frac{MW_{air}}{385.5} = \frac{28.96}{385.5} = 0.075\ \frac{lb}{ft^3} \qquad \textbf{\textit{Equation 3}}$$

$$\rho_{vg} = \frac{MW_{vg}}{385.5} \frac{lb}{ft^3} \qquad \textbf{\textit{Equation 4}}$$

$$\rho_{s,cent} = \frac{MW_{H_2O}}{385.5} = \frac{18.02}{385.5} = 0.047\ \frac{lb}{ft^3} \qquad \textbf{\textit{Equation 5}}$$

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The density of the Vent Gas plus Center Steam ($\rho_{vg+s,cent}$) is calculated by combining the mass flow rates of the Vent Gas and Center Steam and dividing by the combined volumetric flow rates of the Vent Gas and Center Steam. This is shown in Equation 6.

$$\rho_{vg+s,cent} = \frac{m_{vg} + m_{s,cent}}{Q_{vg} + Q_{s,cent}} = \frac{m_{vg} + m_{s,cent}}{\frac{m_{vg}}{\rho_{vg}} + \frac{m_{s,cent}}{\rho_{s,cent}}} \qquad \textbf{\textit{Equation 6}}$$

Calculating Velocity

The velocity of the Vent Gas plus Center Steam ($v_{vg+s,cent}$) is calculated by Equation 7.

$$v_{vg+s,cent} = \frac{Q_{vg} + Q_{s,cent}}{A_{tip-unob}} = \frac{\frac{m_{vg}}{\rho_{vg}} + \frac{m_{s,cent}}{\rho_{s,cent}}}{\mathrm{A}_{tip-unob}} \qquad \textbf{\textit{Equation 7}}$$

The wind velocity is measured directly.

Constants:

$MW_{air} = molecular\ weight\ of\ air\ \left(28.96 \frac{lb}{lbmol}\right)$

$MW_{H_2O} = molecular\ weight\ of\ water\ \left(18.02 \frac{lb}{lbmol}\right)$

$MW_i = molecular\ weight\ of\ component\ i \left(\frac{lb}{lbmol}\right)$

$P = absolute\ ambient\ pressure\ (14.73\ psia)$

$\rho_{air} = density\ of\ air\ \left(\frac{lb}{ft^3}\right) = 0.075 \frac{lb}{ft^3}$

$\rho_{s,cent} = density\ of\ Center\ Steam\ \left(\frac{lb}{ft^3}\right) = 0.047 \frac{lb}{ft^3}$

$R = gas\ constant\ \left(10.73 \frac{psi \cdot ft^3}{lbmol \cdot °R}\right)$

$T_{abs} = absolute\ temperature\ (°R) = 460°R + 68°R = 528\ °R$

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Measured variables:

$MW_{vg} = molecular\ weight\ of\ Vent\ Gas\ \left(\frac{lb}{lbmol}\right)$

$\dot{m}_{s,cent} = mass\ flow\ rate\ of\ Center\ Steam\ \left(\frac{lb}{hr}\right)$

$\dot{m}_{vg} = mass\ flow\ rate\ of\ Vent\ Gas\ \left(\frac{lb}{hr}\right)$

$Q_{s,cent} = volumetric\ flow\ rate\ of\ Center\ Steam\ (scfh)$

$Q_{vg} = volumetric\ flow\ rate\ of\ Vent\ Gas\ (scfh)$

$v_{air} = velocity\ of\ wind\ \left(\frac{ft}{hr}\right)$

Calculated variables:

$A_{tip-unob} = unobstructed\ cross - sectional\ area\ of\ flare\ tip\ (ft^2)$

$MFR = momentum\ flux\ ratio\ (unitless)$

$\rho_{vg} = density\ of\ Vent\ Gas\ \left(\frac{lb}{ft^3}\right)$

$\rho_i = density\ of\ component\ i\ \left(\frac{lb}{ft^3}\right)$

$v_{vg} = velocity\ of\ Vent\ Gas\ \left(\frac{ft}{hr}\right)$

$v_{s,cent} = velocity\ of\ Center\ Steam\ \left(\frac{ft}{hr}\right)$

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APPENDIX 1.6

CALCULATING THE UNOBSTRUCTED CROSS SECTIONAL AREA OF VARIOUS TYPES OF FLARE TIPS

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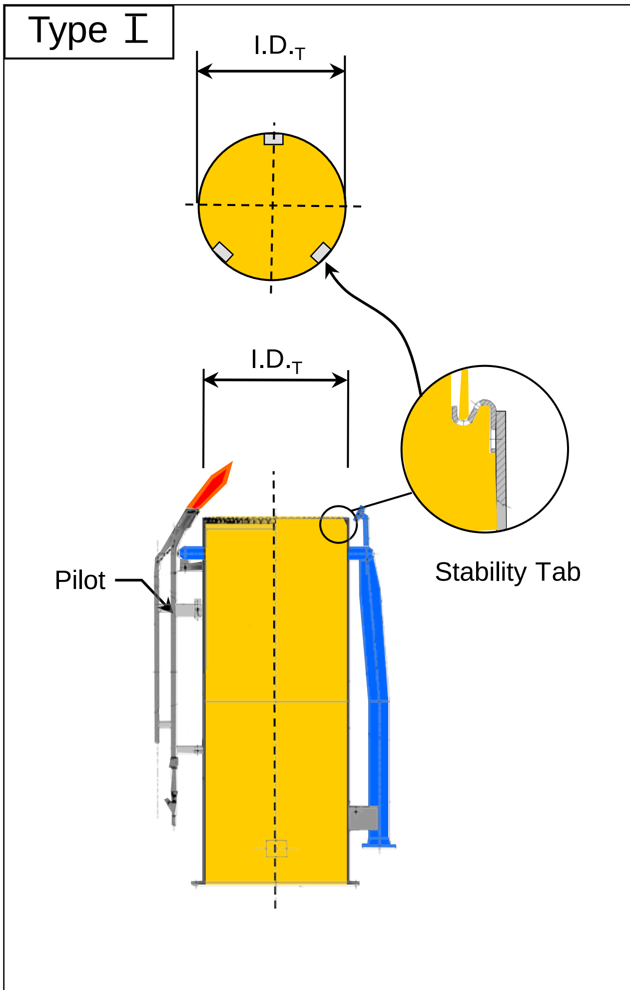


$$A_{tip\text{-}unob} = \pi(I.D._T)^2/4 - (X_T * A_{ST})$$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter Flare Tip

X_T = Number of Stability Tabs

A_{ST} = Area of a Stability Tab

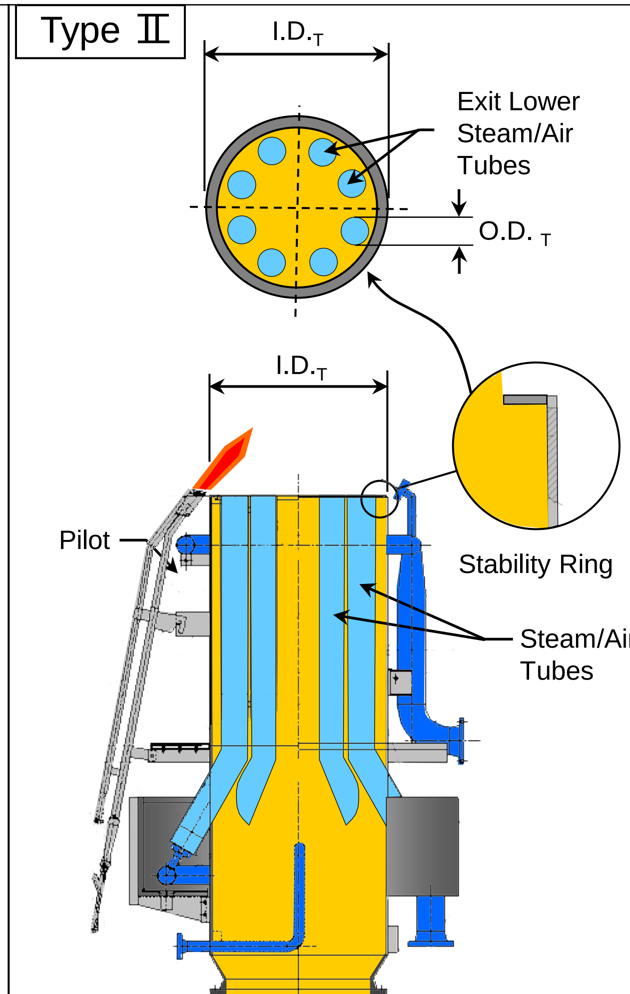
Example: $I.D._T$ = 41.5 inches

X_T = 3

A_{ST} = 3 Sq. inches

$$A_{tip\text{-}unob} = \pi(41.5)^2/4 - (3 * 3)$$

$A_{tip\text{-}unob}$ = 1344 Sq. inches



$$A_{tip\text{-}unob} = \pi(I.D._T)^2/4 - A_{ST} - N_T * \pi * (O.D._T)^2/4$$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter Flare Tip

A_{ST} = Area of Stability Ring

$O.D._T$ = Outside Diameter of Steam/Air Tubes

N_T = Number of Steam/Air Tubes

Example: $I.D._T$ = 47.5 inches

A_{ST} = 100 Sq. inches

$O.D._T$ = 6.5 inches

N_T = 8

$$A_{tip\text{-}unob} = \pi (47.5)^2/4 - 100 - 8 * \pi * (6.5)^2/4$$

$A_{tip\text{-}unob}$ = 1322 Sq. inches

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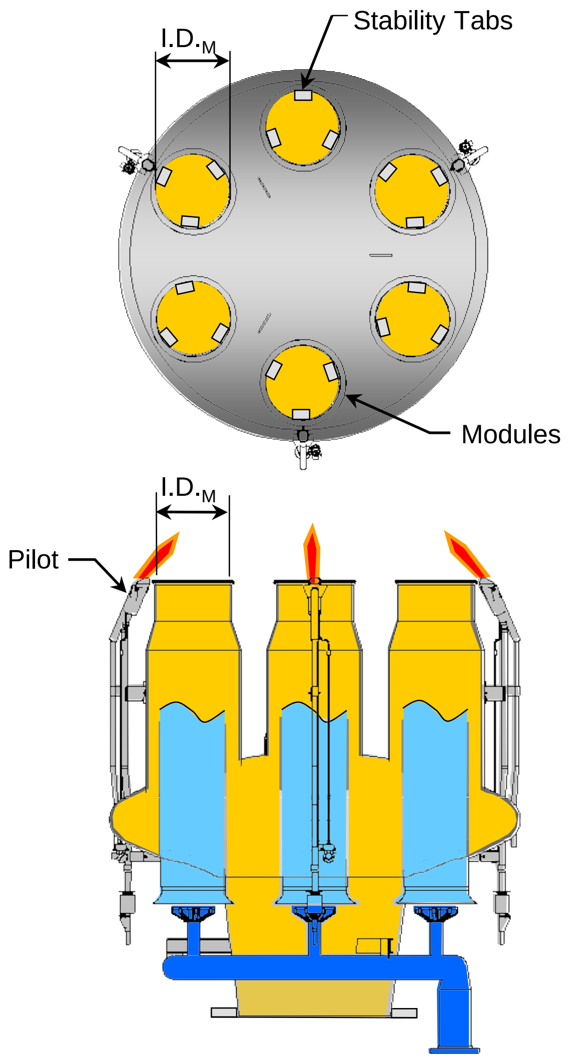
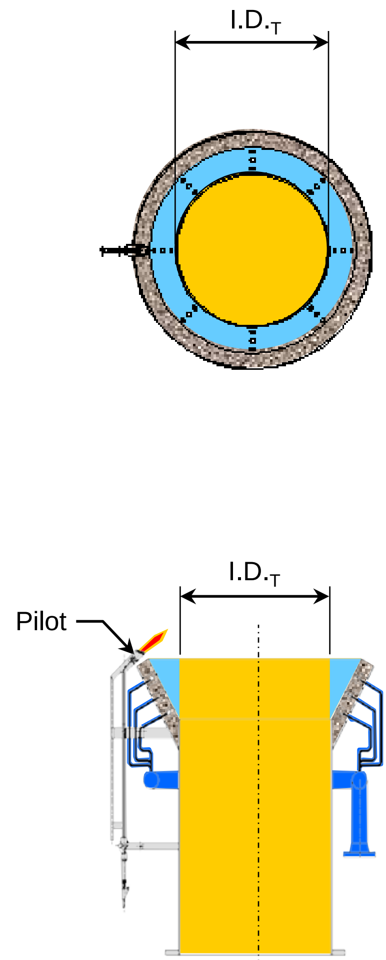
Type III	Type IV
	
$A_{tip\text{-}unob} = N_M * (\pi*(I.D._M)^2/4 - X_T * A_{ST})$	$A_{tip\text{-}unob} = \pi(I.D._T)^2/4$
Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip $I.D._M$ = Inside Diameter of One Tip Module N_M = Number of Modules X_T = Number of Stability Tabs per Module A_{ST} = Area of a Stability Tab	Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip $I.D._T$ = Inside Diameter of Flare Tip
Example: $I.D._M$ = 17 inches N_M = 6 X_T = 3 A_{ST} = 3 Sq. inches	Example: $I.D._T$ = 41.5 inches
$A_{tip\text{-}unob} = 6 * (\pi*(17)^2/4 - 3 * 3)$ $A_{tip\text{-}unob}$ = 1308 Sq. inches	$A_{tip\text{-}unob} = \pi(41.5)^2/4$ $A_{tip\text{-}unob}$ = 1353 Sq. inches

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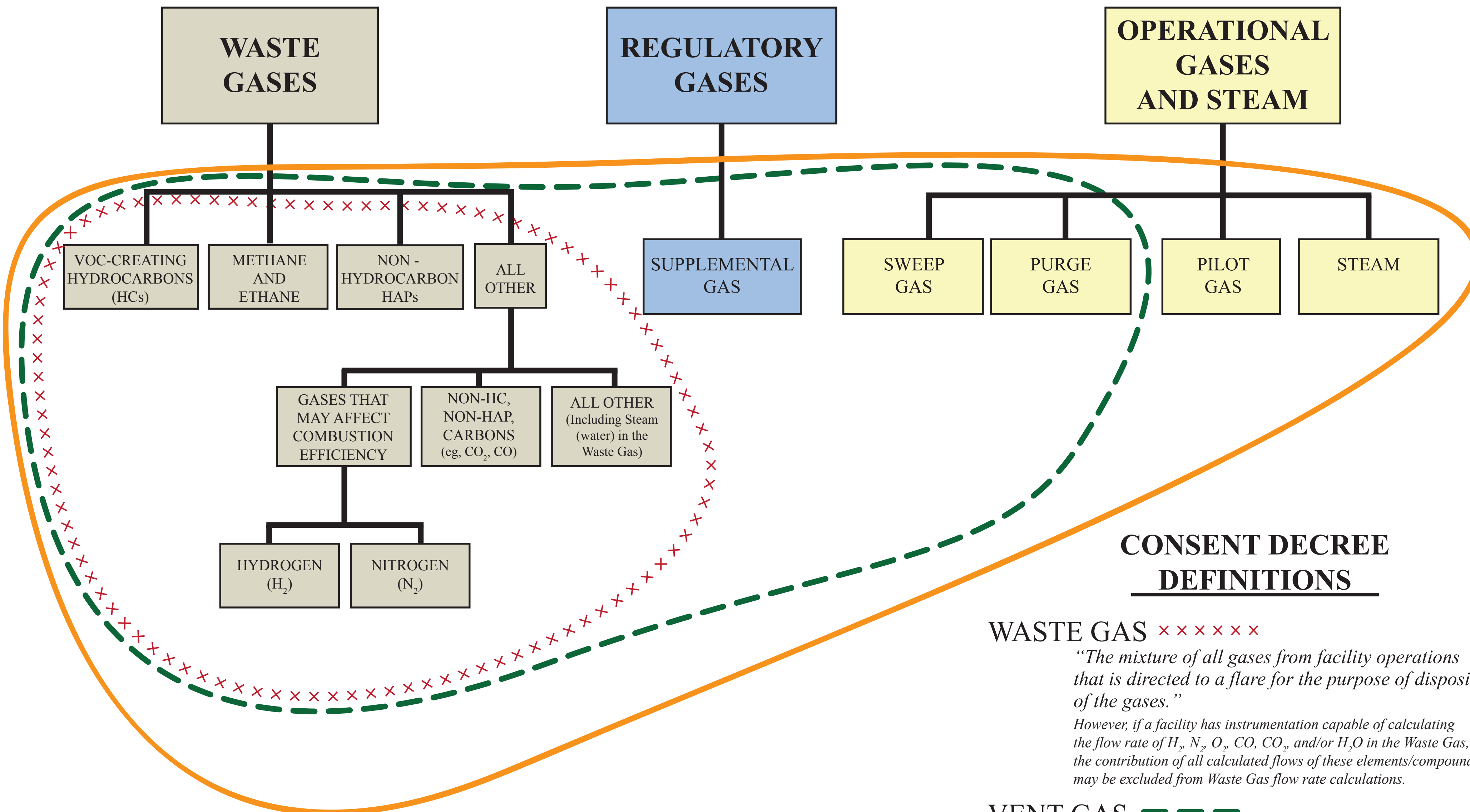
DEPICTION OF GASES ASSOCIATED WITH STEAM-ASSISTED FLARES

DEPICTION OF GASES ASSOCIATED WITH STEAM-ASSISTED FLARES



CONSENT DECREE DEFINITIONS

WASTE GAS × × × × × ×

"The mixture of all gases from facility operations that is directed to a flare for the purpose of disposing of the gases."

However, if a facility has instrumentation capable of calculating the flow rate of H_2, N_2, O_2, CO, CO_2, and/or H_2O in the Waste Gas, the contribution of all calculated flows of these elements/compounds may be excluded from Waste Gas flow rate calculations.

VENT GAS

"The mixture of all gases found prior to the flare tip. This includes all Waste Gas, Supplemental Gas, Sweep Gas, and Purge Gas."

COMBUSTION ZONE GAS

"The mixture of all gases and steam found just after the flare tip. This includes all Vent Gas, Pilot Gas, and Total Steam."

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APPENDIX 1.8

OUTLINE OF REQUIREMENTS FOR THE FLARE DATA AND INITIAL MONITORING SYSTEMS REPORT

APPENDIX 1.8

OUTLINE OF REQUIREMENTS FOR THE FLARE DATA AND INITIAL MONITORING SYSTEMS REPORT

1. Facility-Wide

   1.1 Facility plot plan showing the location of each flare in relation to the general plant layout

2. General Description of Flare

   2.1 Ground or elevated
   2.2 Type of assist system
   2.3 Simple or integrated (*e.g.*, sequential, staged)
   2.4 Date first installed
   2.5 History of any physical changes to the Flare
   2.6 Whether the Flare is a Temporary-Use Flare, and if so, the duration and time periods of use
   2.7 Flare Gas Recovery System ("FGRS"), if any, and date first installed

3. Flare Components: Complete description of each major component of the Flare, except the Flare Gas Recovery System (*see* Part 5), including but not limited to:

   3.1 Flare stack (for elevated flares)
   3.2 Flare tip
      3.1.2.1 Date installed
      3.1.2.2 Manufacturer
      3.1.2.3 Tip Size
      3.1.2.4 Tip Drawing
   3.3 Knockout or surge drum(s) or pot(s), including dimensions and design capacities
   3.4 Water seal(s), including dimensions and design parameters
   3.5 Flare header(s)
   3.6 Sweep Gas system
   3.7 Purge gas system
   3.8 Pilot gas system
   3.9 Supplemental gas system
   3.10 Assist system
   3.11 Ignition system

4. Simplified process diagram(s) showing the configuration of the components listed in Paragraph 3

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5. Existing Flare Gas Recovery System ("FGRS")

   5.1 Complete description of each major component, including but not limited to:
      5.1.1 Compressor(s), including design capacities
      5.1.2 Water seal(s), rupture disk, or similar device to divert the flow
   5.2 Maximum actual past flow on an scfm basis and the annual average flow in scfm for the five years preceding Date of Lodging
   5.3 Simplified schematic showing the FGRS
   5.4 Process Flow Diagram that adds the FGRS to the PDF(s) in Part 4

6. Flare Design Parameters

   6.1 Maximum Vent Gas Flow Rate and/or Mass Rate
   6.2 Maximum Sweep Gas Flow Rate and/or Mass Rate
   6.3 Maximum Purge Gas Flow and/or Mass Rate, if applicable
   6.4 Maximum Pilot Gas Flow and/or Mass Rate
   6.5 Maximum Supplemental Gas Flow Rate and/or Mass Rate
   6.6 If steam-assisted, Minimum Total Steam Rate, including all available information on how that Rate was derived

7. Gases Venting to Flare

   7.1. Sweep Gas
      7.1.1 Type of gas used
      7.1.2 Actual set operating flow rate (in scfm)
      7.1.3 Average lower heating value expected for each type of gas used
   7.2 Purge Gas, if applicable
      7.2.1 Type of gas used
      7.2.2 Actual set operating flow rate (in scfm)
      7.2.3 Average lower heating value expected for each type of gas used
   7.3 Pilot Gas
      7.3.1 Type of gas used
      7.3.2 Actual set operating flow rate (in scfm)
      7.3.3 Average lower heating value expected for each type of gas used
   7.4 Supplemental Gas
      7.4.1 Type of gas used
      7.4.2 Average lower heating value expected for each type of gas used
   7.5 Steam (if applicable)
      7.5.1 Drawing showing points of introduction of Lower, Center, Upper, and any other steam
   7.6 Simplified flow diagram that depicts the points of introduction of all gases, including Waste Gases, at the Flare (in this diagram, the detailed drawings of 7.5.1 may be simplified; in addition, detailed Waste Gas mapping is not required; a simple identification of the header(s) that carries(y) the Waste Gas to the Flare and show(s) its(their) location in relation to the location of the introduction of the other gases is all that is required)

APPENDIX 1.8

8. Existing Monitoring Systems

    8.1 A brief narrative description, including manufacturer and date of installation, of all existing monitoring systems, including but not limited to:

        8.1.1 Waste Gas and/or Vent Gas flow monitoring
        8.1.2 Waste Gas and/or Vent Gas heat content analyzer
        81.3 Sweep Gas flow monitoring
        8.1.4 Purge Gas flow monitoring
        8.1.5 Supplemental Gas flow monitoring
        8.1.6 Steam flow monitoring
        8.1.7 Waste Gas or Vent Gas molecular weight analyzer
        8.1.8 Gas Chromatograph
        8.1.9 Sulfur analyzer(s)
        8.1.10 Video camera
        8.1.11 Thermocouple

    8.2 Drawing(s) showing locations of all existing monitoring systems

9. Monitoring Equipment to be Installed to Comply with Consent Decree

10. Narrative Description of the Monitoring Methods and Calculations that will be used to comply with the NHV_{CZ}, S/VG, and MFR Requirements in the Consent Decree

11. Identification of Calibration Gases to be used to comply with Appendix 1.10

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APPENDIX 1.9

LIST OF COMPOUNDS A GAS CHROMATOGRAPH MUST BE CAPABLE OF SPECIATING

APPENDIX 1.9

LIST OF COMPOUNDS A GAS CHROMATOGRAPH MUST BE CAPABLE OF SPECIATING

The Gas Chromatograph must be capable of speciating the Vent Gas into the following:

1. Hydrogen
2. Oxygen
3. Nitrogen
4. Carbon Dioxide
5. Carbon Monoxide
6. Methane
7. Ethane
8. Ethene (aka: Ethylene)
9. Acetylene
10. Propane
11. Propene (aka: Propylene)
12. 2-Methylpropane (aka: iso-Butane)
13. Butane (aka: n-Butane)
14. But-1-ene (aka: butene, alpha-butylene) and 2-methylpropene (aka: iso-butylene, iso-butene) (these two constituents will be measured on the same column and the reported result will be one value: the sum of the two constituents)
15. E-but-2-ene (aka: beta-butylene, trans-butene)
16. Z-but-2-ene (aka: beta-butylene, cis-butene)
17. 1,3 butadiene
18. Pentane plus (aka: C_5 plus) (*i.e.*, all HCs with five Cs or more)
19. Hydrogen Sulfide

Outputs from the Gas Chromatograph shall be on a mole percent basis except for Hydrogen Sulfide which will be on a parts per million basis.

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APPENDIX 1.10

EQUIPMENT AND INSTRUMENTATION TECHNICAL SPECIFICATIONS AND QUALITY ASSURANCE/QUALITY CONTROL REQUIREMENTS

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EQUIPMENT AND INSTRUMENTATION TECHICAL SPECIFICATIONS AND QUALITY ASSURANCE/QUALITY CONTROL REQUIREMENTS

I. VENT GAS FLOW METER

a. Velocity Range: 0.1–250 ft/sec

b. Repeatability: ± 1% of reading over the velocity range

c. Design Accuracy: ± 5% initially to 40%, 60%, and 90% of monitor full scale as certified by the manufacturer

d. Operational Accuracy: ± 20% of reading over the velocity range of 0.1–1 ft/s and ± 5% of reading over the velocity range of 1–250 ft/s

e. Installation: Applicable AGA, ANSI, API, or equivalent standard

f. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F

g. QA/QC: Annual calibration shall be conducted.

h. Pressure and Temperature Sensors: *See* Part IV below.

II. VENT GAS AVERAGE MOLECULAR WEIGHT ANALYZER (may be part of the Vent Gas Flow Meter)

a. Molecular Weight Range and Accuracy:

i. Range: 0 to 60 gr/grmol

ii. Accuracy: ± 1.2 gr/grmol if a Vent Gas Flow Meter or BTU analyzer that monitors the flare is capable of continuously analyzing Molecular Weight;
± 3.0 gr/grmol if and only if: (i) the Vent Gas Flow Meter that monitors the flare is not capable of continuously analyzing Molecular Weight; (ii) there is no BTU Analyzer that monitors the flare or the BTU Analyzer is not capable of continuously analyzing Molecular Weight; and (iii) a Gas Chromatograph is used for the purpose of continuously analyzing Molecular Weight

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III. STEAM FLOW METER

a. Repeatability: ± 1% of reading over the range of the instrument

b. Accuracy: ± 1% full scale on a volumetric basis
± 2.5% full scale on a mass basis

c. Installation: Applicable AGA, ANSI, API, or equivalent standard

d. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F

e. QA/QC: Annual calibration shall be conducted.

f. Pressure and Temperature Sensors: *See* Part IV below.

IV. VENT GAS AND STEAM FLOW METERS: PRESSURE AND TEMPERATURE SENSORS

a. Temperature monitor must be calibrated annually to ± 5%.

b. Pressure monitor must be calibrated annually to within ± 5%.

V. GAS CHROMATOGRAPH ("GC")

A. General

a. Accuracy: The gas chromatography system shall be maintained to be accurate within 5% of full scale.

b. 8-Hour Repeatability: ± 1.0% of full scale on a volumetric basis over the full range

c. The minimum sampling frequency shall be one sample every 15 minutes.

d. The GC shall be capable of speciating all gas constituents listed in Appendix 1.9.

e. The sampling system sample line shall be heat traced and maintained at no lower than 135 degrees Fahrenheit with no cold spots. The sampling cabinet shall be maintained at no lower than 125 degrees Fahrenheit. All system components shall be heated, including the probe external to the flare piping, calibration valve, sample lines, sampling loop (or sample introduction system), and GC oven.

APPENDIX 1.10

f. Where technically feasible, the sampling location should be at least two equivalent duct diameters downstream from the nearest control device, point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate occurs. The location should not be close to air in-leakages. Where technically feasible, the location should also be at least 0.5 diameters upstream from the exhaust or control device.

B. Gas Chromatograph Calibration Standards

1. **Net Heating Value and Analyte Measurements**. For the Net Heating Value and Analyte measurements, the GC shall be operated and maintained in accordance with Performance Specification 9 ("PS9") of Appendix B of 40 C.F.R. Part 60 except:

a. Daily Validation Procedure. Instead of the daily mid-level validation procedure in Section 10.2 of PS9, a daily low-level validation procedure shall be conducted on the calculated Net Heating Value of a certified calibration gas mixture that is developed using the concentration of each analyte specified in Column 1 of Table 1 below. The average instrument response shall not vary by more than 10 percent from the Net Heating Value of the certified calibration gas mixture.

b. Quarterly Validation Procedure. The multi-point calibration error check procedure in Section 10.1 of PS9 shall be conducted quarterly for the analytes listed in Subparagraph V.B.1.c below. No calibrations will be required after routine maintenance or repair where such activities do not have the potential to alter the sampling or analysis of the gas. The GC must meet the calibration performance criteria in Sections 13.1 and 13.2 of PS9 for the listed analytes, such that: (i) the average instrument response must not differ by more than 10 percent of each analyte calibration gas value; and (ii) the precision and linearity check of each analyte listed below shall not deviate by more than 5 percent from the average concentration measured.

c. The analytes to be used are:

i. Hydrogen
ii. Nitrogen
iii. Methane
iv. Ethane
v. Propane
vi. Propylene
vii. Ethylene

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d. The calibration gas mixtures may be set by the procedures identified in Section 7.1 of PS9 or may be within 10 percent of the concentration values listed in Table 1. The gases must be certified to ± 2 percent.

Table 1: Calibration Gas Mixtures for Net Heating Value Calibrations/Validations[1]

Component	Daily Low-Level Gas (Col. 1)	Quarterly Low-Level Gas (Col. 2)	Quarterly Mid-Level Gas (Col. 3)	Quarterly High-Level Gas (Col. 4)
Hydrogen	8	8	30	12
Nitrogen	65	65	8	5
Methane	22	22	48	30
Ethane	2	2	3	30
Propane	1	1	2	15
Propylene	1	1	8	5
Ethylene	1	1	1	3
NHV (Btu/scf) Unadjusted for H2	310	310	793	1273

[1] The individual analytes are in volume percent.

2. **H_2S Measurement**. For the H_2S measurement, the GC shall be operated and maintained in accordance with Performance Specification 7 of Appendix B of 40 C.F.R. Part 60. Quality assurance procedures set forth in Appendix F of 40 C.F.R. Part 60 shall be followed. The span shall be set at 300 ppmv H_2S or as required by NSPS Subpart Ja, if different.

VI. Calculation of Instrument Downtime

1. For purposes of calculating the 110 hours per calendar quarter of instrument downtime allowed pursuant to Paragraphs 28 and 60.a for SDP's Regular-Use Flares and for purposes of calculating the 5% of instrument downtime allowed pursuant to Paragraphs 28 and 60.b for SDP's Temporary-Use Flares, the time used for GC calibration and validation activities required by Subparagraph V.B.1 of this Appendix may be excluded.

2. Any hour that meets the requirements of 40 C.F.R. § 60.13(h)(2) shall not be counted toward instrument downtime. Specifically:

(i) For a full operating hour (any clock hour where the flare is In Operation (*i.e.*, Capable of Receiving Sweep, Supplemental, and/or Waste Gas) for 60 minutes), if there are at least four valid data points to calculate the

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hourly average (that is, one data point in each of the 15-minute quadrants of the hour), then there is no period of instrument downtime;

(ii) For a partial operating hour (any clock hour where the flare is In Operation (*i.e.*, Capable of Receiving Sweep, Supplemental, and/or Waste Gas) for less than 60 minutes), if there is at least one valid data point in each 15-minute quadrant of the hour in which the flare is In Operation (*i.e.*, Capable of Receiving Sweep, Supplemental, and/or Waste Gas) to calculate the hourly average, then there is no period of instrument downtime; and

(iii) For any operating hour in which required maintenance or quality-assurance activities on the instruments or monitoring systems associated with the flare are performed:

(A) If the flare is In Operation (*i.e.*, Capable of Receiving Sweep, Supplemental, and/or Waste Gas) in two or more quadrants of the hour and if there are at least two valid data points separated by at least 15 minutes to calculate the hourly average, then there is no period of instrument downtime; or

(B) If the flare is In Operation (*i.e.*, Capable of Receiving Sweep, Supplemental, and/or Waste Gas) in only one quadrant of the hour and if there is at least one valid data point to calculate the hourly average, then there is no period of instrument downtime.

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APPENDIX 1.11

WASTE GAS MAPPING: LEVEL OF DETAIL NEEDED TO SHOW MAIN HEADERS AND PROCESS UNIT HEADERS

APPENDIX 1.11

WASTE GAS MAPPING:
LEVEL OF DETAIL NEEDED TO SHOW MAIN HEADERS AND PROCESS UNIT HEADERS

Purpose:

Waste Gas Mapping is required in order to identify the source(s) of waste gas entering each Covered Flare. Waste Gas Mapping can be done using instrumentation, isotopic tracing, acoustic monitoring, and/or engineering estimates for all sources entering a flare header (e.g. pump seal purges, sample station purges, compressor seal nitrogen purges, relief valve leakage, and other sources under normal operations). This Appendix outlines what needs to be included as the Waste Gas Mapping section within the Initial Waste Gas Minimization Plan ("Initial WGMP")

Waste Gas Mapping Criteria:

For purposes of waste gas mapping, a main header is defined as the last pipe segment prior to the flare knock out drum. Process unit headers are defined as pipes from inside the battery limits of each process unit that connect to the main header. For process unit headers that are greater than or equal to six (6) inches in diameter, flow ("Q") must be identified and quantified if it is technically feasible to do so. In addition, all sources feeding each process unit header must be identified and listed in a table, but not necessarily individually quantified. For process unit headers that are less than six (6) inches in diameter, sources must be identified, but they do not need to be quantified.

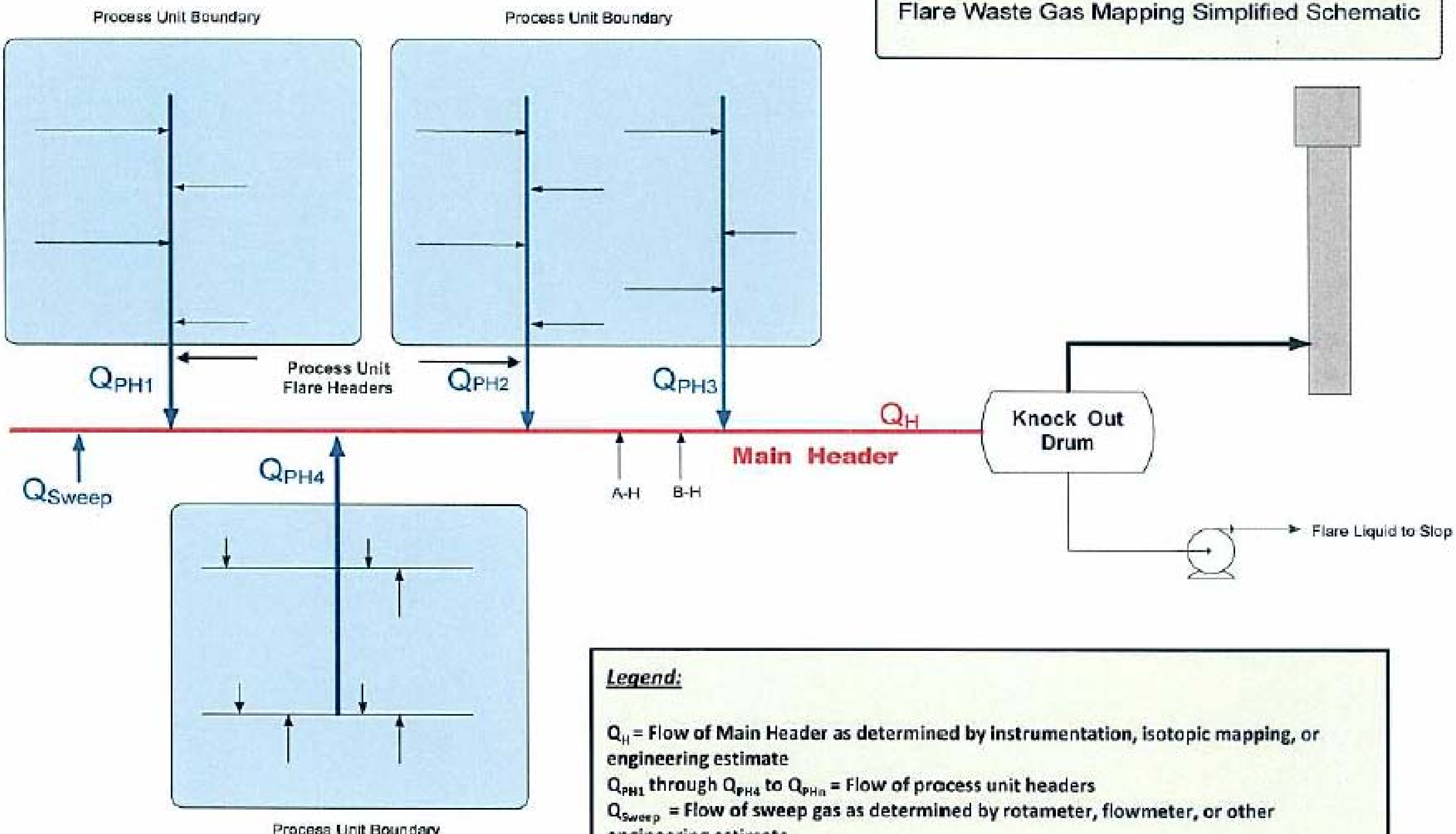
Waste Gas Mapping Submission Requirements:

For each Covered Flare, the following shall be included within the Waste Gas Mapping section of the Initial WGMP:

1. Simplified Schematic consistent with the example schematic included on the second page of this Appendix.

2. Table of all sources connected to each flare main header and process unit header consistent with the Table included on the third page of this Appendix.

Flare Waste Gas Mapping Simplified Schematic



Legend:

Q_H = Flow of Main Header as determined by instrumentation, isotopic mapping, or engineering estimate
Q_{PH1} through Q_{PH4} to Q_{PHn} = Flow of process unit headers
Q_{Sweep} = Flow of sweep gas as determined by rotameter, flowmeter, or other engineering estimate

Table 1: Example of Flare Source Description Table

Process Unit Header	Sources	Detailed Source Description
Q_{PH1} (Ex: FCCU Gas Con Unit)	3 PSVs	PSV-14 on 110-D-5 Gas Con Absorber PSV-12 on 110-D-1 Amine Scrubber PSV-7 on 110-F-1 Batch Caustic Vessel
	2 Pump Seal Purges	110-G-1 LPG Pump 110-G-2 Rich Amine Pump
	1 Sample Station	110-S-1 LPG
	1 PSV	PSV 17 on 112-D-1 Main Column
	1 Pressure Control Valve	PCV 21 – Emergency Wet Gas Compressor
	1 PSV	PSV-21 on Flush Oil Drum
	1 Pump Seal Purge	110-G-23 Slurry Oil Pump
Q_{PH2} (Ex: Gas Oil Treater)	Continue same as PH1	Continue same as PH1
Q_{PH3}	Continue same as PH1	Continue same as PH1
Q_{PH4}	Continue same as PH1	Continue same as PH1
A-H	1 PSVs	PSV-17 on 109-E-42 Slurry Heat Exchanger
B-H	2 Pump Seal Purges	110-G-3 Gas Oil Feed 110-G-4 Main Column Reflux

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APPENDIX 1.12

REPRESENTATIONS OF DISCONTINUOUS WAKE DOMINATED FLOW

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REPRESENTATIONS OF DISCONTINUOUS WAKE DOMINATED FLOW

Definition

"Discontinuous Wake Dominated Flow" shall mean gas flow exiting a Flare tip that is identified visually by:

i. The presence of a flame that is: (1) immediately adjacent to the exterior of the Flare tip body; and (2) below the exit plane of the Flare tip; and

ii. A discontinuous flame, such that pockets of flame are detached from the portion of the flame that is immediately adjacent to the exterior of the Flare tip body.

Background

The gases present just outside of the flare tip are influenced by several factors. All of these factors are present all of the time, but as process and environmental conditions change, the relative "strength" of each factor will change. The most dominant factors will dictate the flow of the Vent Gases, *i.e.*, will determine the size, shape, and direction of the flame. Some of the influences on the Vent Gases are:

- The low pressure region, or wake, that is downwind and next to the flare.
- The temperature gradient that causes the warm combustion gases to be buoyant, or rise.
- The inertia, or resistance to changes in speed and direction, of the Vent Gases as they exit the tip.

The regimes below show how a flame will appear when the most dominant influences are, respectively, the wake, the buoyancy due to temperature, and the inertia due to the gas's momentum.

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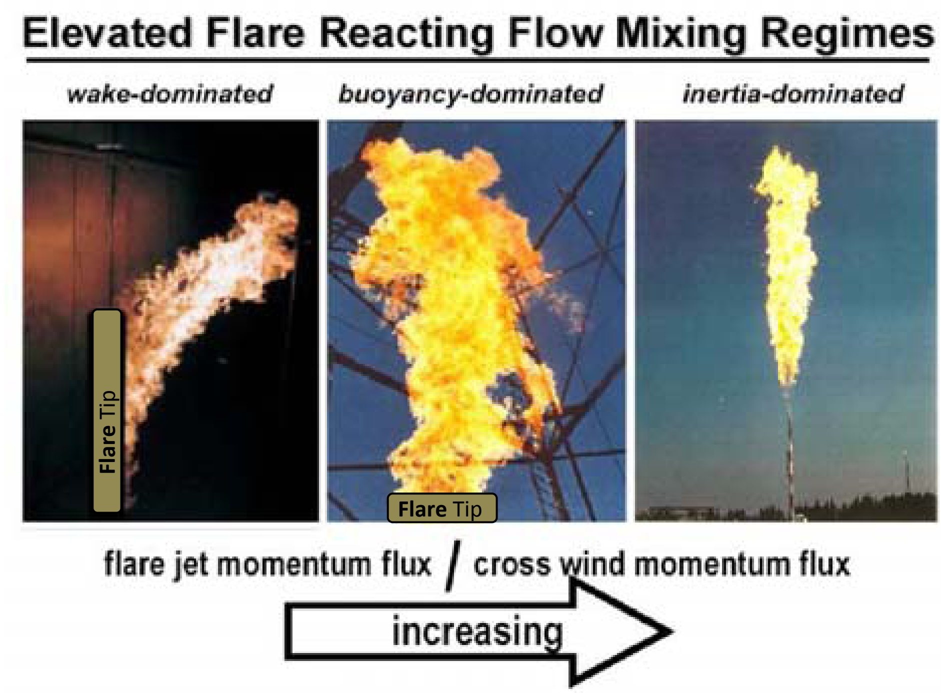
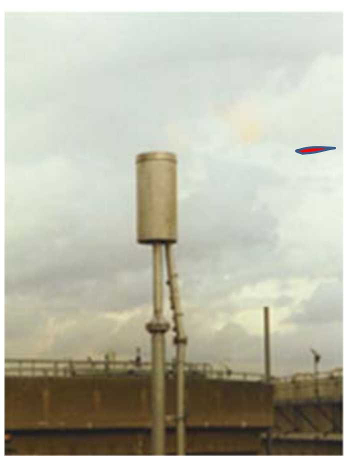


Images take from: Practical Implications of Prior Research on Today's Outstanding Flare Emissions Questions and a Research Program to Answer Them
James Seebold, ChevronTexaco (Retired)
Peter Gogolek, Natural Resources Canada
John Pohl, Virginia Polytechnic Institute and State University
Robert Schwartz, John Zink Company LLC

As a wake dominated flame becomes less stable, it becomes segmented, or discontinuous. The following is a representation of "Discontinuous Wake Dominated Flow." The red area is an artist's rendition of a flame.



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The following image represents a flame below the plane of the exit of the flare tip. However, since the flame is not discontinuous and not immediately adjacent to the tip, this image would not represent Discontinuous Wake Dominated Flow.

The following image represents a flame below the plane of the exit of the flare tip and attached to the tip. However, since the flame is not discontinuous, this image would not represent Discontinuous Wake Dominated Flow.

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In order for the flame to be deemed discontinuous, it should be segmented, and not merely possess small pockets of flame at the outer boundary of a single large cohesive flame. Furthermore, a discontinuous flame will normally appear thin relative to its length, and lack a single bulbous core. The following image represents a flame with a small pocket of flame only at the outer edges of the broad main flame. This would not represent a discontinuous flame, and therefore would not be Discontinuous Wake Dominated Flow.

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APPENDIX 1.13

CALCULATING THE AMOUNT OF STIPULATED PENALTIES DUE FOR VIOLATING LIMITATIONS OF FLARING WHEN THE STIPULATED PENALTIES ARE BASED ON EXCESS VOCS AND SO_2 EMITTED

APPENDIX 1.13

CALCULATING THE AMOUNT OF STIPULATED PENALTIES DUE FOR VIOLATING LIMITATIONS ON FLARING WHEN THE STIPULATED PENALTIES ARE BASED ON EXCESS VOCs AND SO_2 EMITTED

I. Stipulated Penalties for Violating the 30-Day Rolling Average Limit. The following equation shall be used to calculate the amount of stipulated penalties due for violating the 30-day rolling average limit on flaring:

$$\text{Penalty due} = \sum_{i=1}^{n} [\$\$_{30d,VOC} \times EE_{30d,VOC}] + [\$\$_{30d,SO2} \times EE_{30d,SO2}] \quad \textbf{(Eq. 1)}$$

Where:

n	=	Each day the 30-day rolling average limit is exceeded
$\$\$_{30d,VOC}$	=	Dollars per ton of VOC for violating the 30-day limit ($300/ton because SDP Refinery is in an ozone nonattainment area)
$EE_{30d,VOC}$	=	30-day average VOC emissions above the flow limit on day limit is violated; *see* Equation 3.a
$\$\$_{30d,SO2}$	=	Dollars per ton of SO_2 for violating 30-day limit ($100/ton)
$EE_{30d,SO2}$	=	30-day average SO_2 emissions above the flow limit on day limit is violated; *see* Equation 4.a

II. Stipulated Penalties for Violating the 365-day Rolling Average Limit. The following equation shall be used to calculate the amount of stipulated penalties due for violating the 365-day rolling average limit on flaring:

$$\text{Penalty due} = \sum_{i=1}^{n} [\$\$_{365d,VOC} \times EE_{365d,VOC}] + [\$\$_{365d,SO2} \times EE_{365d,SO2}] \quad \textbf{(Eq. 2)}$$

Where:

n	=	Each day the 365-day rolling average limit is exceeded
$\$\$_{365d,VOC}$	=	Dollars per ton of VOC for violating 365-day limit ($120/ton because SDP Refinery is in an ozone nonattainment area)
$EE_{365d,VOC}$	=	365-day average VOC emissions above the flow limit on day limit is violated; *see* Equation 3.b
$\$\$_{365d,SO2}$	=	Dollars per ton of SO_2 for violating 30 day cap ($40/ton)
$EE_{365d,SO2}$	=	365-day average SO_2 emissions above the flow limit on day limit is violated; *see* Equation 4.b

APPENDIX 1.13

III. <u>Calculating Average Emissions of VOCs Above the Flow Limit When Violating the 30-Day and 365-Day Rolling Average Limit</u>

A. <u>Violating the 30-day rolling average limit</u>. The following equation shall be used to calculate the 30-day average VOC emissions above the flow limit for the day that the 30-day rolling average limit is violated:

$$EE_{30d,VOC} = [Q_{30d,actual} - Q_{30d,allowable}][VOC_{30d,vol\ fraction}]\ [.0026]\ [MW_{30d,VOC}]\ [.0005][1 - CE_{30d,as\ fraction}] \qquad \textbf{(Eq. 3.a)}$$

Where:

$EE_{30d,VOC}$ = 30-day average VOC emissions above the flow limit on the day that the 30-day rolling average limit is violated, in tons per day

$Q_{30d,actual}$ = Actual 30-day rolling average Waste Gas Flow Rate on the day that the 30-day rolling average limit is violated, in scfd

$Q_{30d,allowable}$ = Allowable 30-day rolling average Waste Gas Flow Rate taken from the Consent Decree, in scfd

$VOC_{30d,vol\ fraction}$ = 30-day flow weighted rolling average VOC volume fraction in the Waste Gas on the day that the 30-day rolling average limit is violated. [NOTE: This is the VOC fraction in the Waste Gas, not the Vent Gas.] The daily flow weighted average VOC volume fraction shall be determined from an average of the hourly average VOC concentration weighted by waste gas flow. The 30-day flow weighted rolling average VOC volume fraction shall be determined from daily flow weighted CE and daily flow of waste gas.

.0026 = 1 lb-mole VOC/385.5 scf

$MW_{30d,VOC}$ = 30-day flow weighted rolling average Molecular Weight of VOCs on the day that the 30-day rolling average limit is violated, in lb/lb-mole. The daily flow weighted average molecular weight (MW) shall be determined from an average of the hourly average MW weighted by waste gas flow. The 30-day flow weighted rolling average MW shall be determined from daily flow weighted MW and daily flow of waste gas.

.0005 = 1 ton/2000 lb

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$CE_{30d,as\ fraction}$ = 30-day rolling average Combustion Efficiency ("CE") determined from the NHV_{cz} of the Combustion Zone Gas as follows:

NHV_{cz} (BTU/scf)	$CE_{as\ fraction}$
$NHV_{cz} < 95$	0.0
$95 <= NHV_{cz} < 300$	$[0.16*(-95+ NHV_{cz})]/[1+0.16*(-95+ NHV_{cz})]$
$300 <= NHV_{cz} < 350$	0.98
$350 <= NHV_{cz} < 425$	0.985
$425 <= NHV_{cz} < 500$	0.9875
$500 <= NHV_{cz} < 600$	0.99
$600 <= NHV_{cz}$	0.995

Combustion Efficiency shall be determined hourly from the hourly average NHV_{cz} using the table above. The daily flow weighted average CE shall be determined from an average of the hourly average CE values weighted by waste gas flow. The 30-day flow weighted rolling average CE shall be determined from daily flow weighted CE and daily flow of waste gas.

B. **<u>Violating the 365-day rolling average limit</u>**. To calculate the 365-day average VOC emissions above the flow limit for the day that the 365-day rolling average limit is violated:

Substitute "365" everywhere "30" appears in Equation 3.a **(Eq. 3.b)**

[Appendix continued on next page]

IV. Calculating the Average Emissions of SO_2 Above the Flow Limit when Violating the 30-Day and 365-Day Rolling Average Limit

A. Violating the 30-day rolling average limit. The following equation shall be used to calculate the 30-day average SO_2 emissions above the flow limit for the day that the 30-day rolling average limit is violated:

$$EE_{30d,SO2} = [Q_{30d,actual} - Q_{30d,allowable}]\,[C_{30d,H2S}/1{,}000{,}000]\,[8.30 \times 10^{-5}] \qquad \textbf{(Eq. 4.a)}$$

Where:

$EE_{30d,SO2}$	=	30-day average SO_2 emissions above the flow limit on the day that the 30-day rolling average limit is violated, in tons per day
$Q_{30d,actual}$	=	Actual 30-day rolling average Waste Gas Flow Rate on the day that the 30-day rolling average limit is violated, in scfd
$Q_{30d,allowable}$	=	Allowable 30-day rolling average Waste Gas Flow Rate taken from the Consent Decree, in scfd
$C_{30d,H2S}$	=	30-day rolling average concentration of H_2S in Waste Gas on the day that the that the 30-day rolling average limit is violated, in ppmv
8.30×10^{-5}	=	[1 lb-mole H_2S/385.5 scf] [64 lb SO_2/lb-mole H_2S] [Ton/2000 lb]

B. Violating the 365-day rolling average limit. To calculate the 365-day average emissions of SO_2 above the flow limit for the day the 365-day rolling average limit is violated:

Substitute "365" everywhere "30" appears in Equation 4.a **(Eq. 4.b)**

[End of Appendix]

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APPENDIX 1.14

EQUATIONS AND METHODOLOGY TO CALCULATE REFINERY-SPECIFIC COMPLEXITY AND INDUSTRY-AVERAGE COMPLEXITY USING NELSON COMPLEXITY INDEX

APPENDIX 1.14

DETERMINING REFINERY-SPECIFIC AND INDUSTRY-AVERAGE COMPLEXITY THROUGH USE OF THE NELSON COMPLEXITY INDEX

DEFINITIONS:

"Applicable EIA Annual Refinery Publication" shall mean the Annual EIA Refinery Publication that was the most recent one posted on EIA's website prior to a refinery's request for an increase in flaring caps.

"Applicable Form EIA-820" shall mean the Form EIA-820 that forms the source for the requesting refinery's capacity information that is summarized and compiled in the Applicable Annual EIA Refinery Publication.

> *For example, if a refinery requests an increase in flaring caps in March of 2015, the "Applicable Form EIA-820," is the Form EIA-820 that the Refinery submitted prior to February 15, 2014, for its capacities as of January 1, 2014, (and not the Form EIA-820 that the Refinery submitted prior to February 15, 2015, for its capacities as of January 1, 2015). This is because the Applicable EIA Annual Refinery Publication is the one published in June of 2014 (i.e., the last one published prior to March of 2015).*

"Applicable O&GJ Refining Survey" shall mean the survey that is published in December of the year prior to the year of the Applicable EIA Annual Refinery Publication.

> *For example, if the Applicable EIA Annual Refinery Publication is the one published in June of 2014, then the Applicable O&GJ Refinery Survey is the one published in December of 2013 for capacities as of January 1, 2014.*

"EIA" shall mean the United States Energy Information Agency.

"EIA Annual Publication of the Number and Capacity of Petroleum Refineries" or "EIA Annual Refinery Publication" shall mean the information posted on EIA's website on approximately June 21 of each year that compiles and summarizes the data submitted on the Form EIA-820s that each refinery submits prior to February 15 of that year. As of April 2013, the most recent Annual EIA Refinery Publication (*i.e.*, the one from June of 2012) is found at http://www.eia.gov/dnav/pet/pet_pnp_cap1_dcu_nus_a.htm. A printout of this publication is Attachment 1 to this Appendix 1.14.

"Form EIA-820" shall mean the annual report that each refinery is required to submit to the EIA prior to February 15 of each year. The "Report Year" of a Form EIA-820 refers to the capacities that exist as of January 1 of the "Report Year." A copy of a typical Form EIA-820 is Attachment 2 to this Appendix 1.14.

"Oil & Gas Journal Worldwide Refining Survey" or "O&GJ Refining Survey" shall mean the survey that the Oil & Gas Journal publishes in December of each year that lists refining capacities as of January 1 of the following year. A copy of the national refining capacities listed in the December 5, 2011 O&GJ Refining Survey for January 1, 2012 is Attachment 3 to this Appendix 1.14. The relevant United States capacities are highlighted in yellow on the third page of Attachment 3.

APPENDIX 1.14

REFINERY COMPLEXITY. The complexity of the Refinery is to be calculated using the following formula:

Equation 1

$$Complexity = \sum_{n=1}^{i} \left(\frac{NCI_i \times CAP_i}{CAP_{Dist}} \right)$$

Where:

NCI_i = The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for Process Unit i

CAP_i = The throughput capacity for the Refinery's Process Unit i, in barrels per calendar day, which shall be determined as follows:

(a) for a Process Unit that is not new or modified and for which the Applicable EIA Annual Refinery Publication lists total US throughput for that process, the capacity, in barrels per calendar day, that the Refinery reported for Process i on Part 6[/1] of the Applicable Form EIA-820. If the Refinery did not report the capacity of Process i in "barrels per calendar day," but instead reported it in "barrels per stream day," then "barrels per stream day" will be converted to "barrels per calendar day" by multiplying "barrels per stream day" by the following factors: 0.95 for a vacuum distillation unit and 0.9 for all other units; or

(b) for a process unit that is not new or modified, if and only if the Applicable EIA Annual Refinery Publication does not list total US throughput capacity for that process unit, then the Refinery's capacity for that process unit, in barrels per calendar day, listed in the Applicable O&GJ Refining Survey.

(c) for a Process Unit that is new or modified, where the new or modified capacity was not reported on the Applicable Form EIA-820, the projected new or modified unit capacity that is set forth in the air permit application(s) for the post-Lodging modification.

CAP_{DIST} = The Refinery's Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, which shall be determined as follows:

(a) if the post-Lodging modification does not affect the crude capacity, the Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, that the Refinery reported under "Total Operable" capacity on Part 5, Code 401[/1] of the Applicable Form EIA-820; or

(b) if the post-Lodging modification does affect crude capacity, the projected, new capacity set forth in the air permit application(s) for the post-Lodging modification.

[/1] The references to particular "Parts" or "Codes" of Form EIA-820 are to the Parts and Codes as they exist for the Form EIA-820 that was used for Report Year 2012. *See* Attachment 2. To that extent that the "Parts" or "Codes" on Form EIA-820 are changed in the future, the intent of the Parties is that the "Parts" and "Codes" of future forms that correspond most closely to those found on the Form EIA-820 for Report Year 2012 will be used.

APPENDIX 1.14

INDUSTRY AVERAGE COMPLEXITY: The Industry Average Complexity is to be calculated using the following formula:

Equation 2

$$Industry\_Average\_Complexity = \sum_{n=1}^{i} \left(\frac{NCI_i \times ICAP_i}{ICAP_{Dist}} \right)$$

Where:

NCI_i = The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for Process Unit i

$ICAP_i$ = Total US throughput capacity, in barrels per calendar day, for Process Unit i which shall be determined as follows:

(a) from the Applicable EIA Annual Refinery Publication, the total US capacity of Process Unit i in barrels per calendar day. For the total US capacity of those process units that the EIA lists only in "barrels per stream day" and not in "barrels per calendar day," the "barrels per stream day" shall be converted to "barrels per calendar day" by multiplying "barrels per stream day" by the following factors: 0.95 for a vacuum distillation unit and 0.9 for all other units.[/2]

(b) if and only if the Applicable EIA Annual Refinery Publication does not list a total US throughput capacity for a process unit that the Refinery operates, then the total US throughput capacity for that process unit listed in the Applicable O&GJ Refining Survey.

$ICAP_{DIST}$ = From the Applicable EIA Annual Refinery Publication, the total "Operable" US Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day.[3]

/2 For example, for catalytic reforming, the total US capacity as of January 1, 2012, is 3,246,874 barrels per calendar day. *See* Attachment 1 at page 2 (green highlight). Note that the capacity for catalytic reforming on page 1 of Attachment 1 should *not* be used because that is listed in "barrels per stream day," not bpcd. For vacuum distillation, the total US capacity for 2012 is 8,679,643 barrels per stream day. *See id.* at page 1 (orange highlight). This figure would be converted to 8,245,660 barrels per calendar day (8,679,643 x .95).

/3 Total Operable US Atmospheric Crude Oil Distillation Capacity (total $ICAP_{DIST}$) of a January 1, 2012, is 17,322,178 barrels per calendar day. *See* Attachment 1 at page 1 (yellow highlight).

APPENDIX 1.14

Table 1: 2011 Nelson Complexity Index Coefficients

Refining Process	NCI Coefficients
Distillation Capacity	1.00
Vacuum Distillation	1.30
Thermal Processes	2.75
Coking	7.50
Catalytic Cracking	6.00
Catalytic Reforming	5.00
Catalytic Hydrocracking	8.00
Catalytic Hydrorefining	2.50
Catalytic Hydrotreating	2.50
Alkylation	10.00
Polymerization	10.00
Aromatics	20.00
Isomerization	3.00
Lubes	60.00
Asphalt	1.50
Hydrogen (MCFD)	1.00
Oxygenates	10.00
Sulfur Extraction	240.00

APPENDIX 1.14

ATTACHMENT 1

U.S. Energy Information Administration

PETROLEUM & OTHER LIQUIDS

OVERVIEW | DATA | ANALYSIS & PROJECTIONS | GLOSSARY › | FAQS ›

Number and Capacity of Petroleum Refineries

Area: U.S. **Period:** Annual (as of January 1)

Show Data By: Data Series / Area	Graph / Clear	2007	2008	2009	2010	2011	2012	View History
Number of Operable Refineries								
Total Number of Operable Refineries		149	150	150	148	148	144	1982-2012
Operating		145	146	141	137	137	134	1982-2012
Idle		4	4	9	11	11	10	1982-2012
Atmospheric Crude Oil Distillation Capacity								
Operable (Barrels per Calendar Day)		17,443,492	17,593,847	17,671,550	17,583,790	17,736,370	17,322,178	1982-2012
Operating		16,997,792	17,225,797	17,313,550	16,850,194	16,937,024	16,744,291	1982-2012
Idle		445,700	368,050	358,000	733,596	799,346	577,887	1982-2012
Operable (Barrels per Stream Day)		18,425,322	18,558,022	18,681,308	18,581,089	18,953,189	18,560,350	1982-2012
Operating		17,928,522	18,174,072	18,300,358	17,808,082	18,109,882	17,945,443	1982-2012
Idle		496,800	383,950	380,950	773,007	843,307	614,907	1982-2012
Downstream Charge Capacity (Barrels per Stream Day)								
Vacuum Distillation		8,251,451	8,420,501	8,542,281	8,542,643	8,650,243	8,679,643	1982-2012
Thermal Cracking		2,564,080	2,606,260	2,639,090	2,631,676	2,672,376	2,763,356	1982-2012
Total Coking		2,537,480	2,579,660	2,612,490	2,605,076	2,645,776	2,736,756	1987-2012
Delayed Coking		2,331,580	2,374,260	2,454,590	2,500,676	2,486,876	2,577,856	1987-2012
Fluid Coking		205,900	205,400	157,900	104,400	158,900	158,900	1987-2012
Visbreaking		16,000	16,000	16,000	16,000	16,000	16,000	1987-2012
Other (Including Gas Oil)		10,600	10,600	10,600	10,600	10,600	10,600	1987-2012
Catalytic Cracking - Fresh Feed		6,218,957	6,265,697	6,291,871	6,140,121	6,219,721	6,032,512	1982-2012
Catalytic Cracking - Recycle Feed		82,040	78,740	78,740	91,840	95,640	84,890	1982-2012
Catalytic Hydro-Cracking		1,790,682	1,770,325	1,743,300	1,819,700	1,855,600	1,879,600	1982-2012
Distillate		602,800	556,900	593,100	595,200	540,100	596,500	2004-2012
Gas Oil		987,482	1,004,425	1,010,200	1,079,500	1,170,500	1,161,100	2004-2012
Residual		200,400	209,000	140,000	145,000	145,000	122,000	2004-2012
Catalytic Reforming		3,907,510	3,891,938	3,829,338	3,700,463	3,720,613	3,641,813	1982-2012
Low Pressure		2,354,950	2,402,350	2,397,750	2,322,700	2,390,950	2,347,850	1987-2012
High Pressure		1,552,560	1,489,588	1,431,588	1,377,763	1,329,663	1,293,963	1987-2012
Catalytic Hydrotreating/Desulfurization		15,447,136	15,807,478	16,130,823	16,023,206	16,682,897	16,565,262	1982-2012
Naphtha/Reformer Feed		4,453,890	4,348,590	4,334,297	4,281,046	4,441,323	4,360,593	1987-2012
Gasoline		2,221,568	2,420,968	2,415,282	2,394,882	2,578,782	2,519,082	2004-2012
Heavy Gas Oil		2,578,840	2,672,440	2,735,538	2,796,798	2,809,298	2,877,138	1987-2012
Distillate Fuel Oil		5,212,387	5,462,649	5,622,252	5,676,032	6,113,846	6,063,001	1987-2012
Kerosene/Jet Fuel		1,009,450	1,137,010	1,160,110	1,339,150	1,484,850	1,489,750	2004-2012
Diesel Fuel		3,332,671	3,468,471	3,551,211	3,647,211	3,917,611	3,981,411	2004-2012
Other Distillate		870,266	857,168	910,931	689,671	711,385	591,840	2004-2012
Residual Fuel Oil/Other		980,451	902,831	1,023,454	874,448	739,648	745,448	1987-2012
Residual Fuel Oil		331,420	251,200	316,400	246,200	241,000	246,000	2004-2012
Other		649,031	651,631	707,054	628,248	498,648	499,448	2004-2012

Fuels Solvent Deasphalting		379,290	378,350	380,950	383,250	382,750	374,550	1987-2012
Downstream Charge Capacity (Barrels per Calendar Day)								
Catalytic Reforming					3,378,841	3,346,457	3,246,874	2010-2012
Total Coking		2,359,318	2,390,223	2,428,961	2,387,896	2,396,787	2,499,293	1987-2012
Catalytic Cracking - Fresh Feed		5,830,486	5,853,656	5,847,130	5,675,830	5,794,214	5,611,191	1987-2012
Catalytic Hydro-Cracking		1,620,705	1,602,431	1,592,973	1,663,115	1,687,745	1,706,540	1987-2012

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Notes: Idle refineries represent refineries where distillation units were completely idle but not permanently shutdown as of January 1 of the year. See Definitions, Sources, and Notes link above for more information on this table.

Release Date: 6/22/2012
Next Release Date: 6/21/2013

APPENDIX 1.14

ATTACHMENT 2

eia U.S. Energy Information Administration

OMB No. 1905-0165
Expiration Date: 1/31/2013
Version No.:2010.02

FORM EIA-820
ANNUAL REFINERY REPORT
REPORT YEAR 2012

This report is **mandatory** under the Federal Energy Administration Act of 1974 (Public Law 93-275). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning the confidentiality of information in the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly makes to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

PART 1. RESPONDENT IDENTIFICATION DATA

EIA ID NUMBER: 1339570101

If any Respondent Identification Data has changed since the last report, enter an "X" in the box: ☐

Company Name: Shell Oil Co.
Doing Business As:
Site Name: DEER PARK REFG LTD PTNRSHP
Terminal Control Number (TCN):

Physical Address (e.g., Street Address, Building Number, Floor, Suite):
HWY 225
City DEER PARK State: TX Zip: 77536 - 0100

Mailing Address of Contact (e.g., PO Box, RR): If the physical and mailing addresses are the same, only complete the physical address.
P.O. BOX 100
City DEER PARK State: TX Zip: 77536 - 0100

Contact Name: [redacted]
Phone No.: [redacted] Ext: [redacted]
Fax No.: [redacted]
Email address: [redacted]

PART 2. SUBMISSION/RESUBMISSION INFORMATION

If this is a resubmission, enter an "X" in the box: ☐

A completed form must be received by February 15[th] of the designated report year.

Forms may be submitted using one of the following methods:

Email: OOG.SURVEYS@eia.gov

Fax: (202) 586-1076

Secure File Transfer:
https://signon.eia.doe.gov/upload/noticeoog.jsp

Questions? Call: 202-586-6281

Comments: Explain any unusual or substantially different aspects of your current year's operations that affect the data reported. For example, note new processing units, major modifications or retirement of processing units, sale of refinery, etc. (To separate one comment from another, press ALT+ENTER)

U.S. Energy Information Administration

OMB No. 1905-0165
Expiration Date: 1/31/2013
Version No.:2010.02

FORM EIA-820
ANNUAL REFINERY REPORT
REPORT YEAR 2012

EIA ID NUMBER: 1339570101 **RESUBMISSION:**

PART 3. FUEL, ELECTRICITY, AND STEAM PURCHASED & CONSUMED AT THE REFINERY DURING 2011

REDACTED

PART 5. ATMOSPHERIC CRUDE OIL DISTILLATION CAPACITY AS OF JANUARY 1

Atmospheric Crude Oil Distillation Capacity	Code	Barrel per Calendar Day[2]	Barrels per Stream Day
2012: Operating	399	327000	327000
Idle	400	0	0
Total Operable	401	327000	327000
2013: Operable	501		327000

[2] Barrels per Calendar Day Operating, Idle and Total Operable Capacity (Codes 399, 400 and 401) **must match** the comparable capacity numbers reported on the Form EIA-810, "Monthly Refinery Report," filed for January 2012.

U.S. Energy Information Administration

OMB No. 1905-0165
Expiration Date: 1/31/2013
Version No.:2010.02

FORM EIA-820
ANNUAL REFINERY REPORT
REPORT YEAR 2012

EIA ID NUMBER: 1339570101 **RESUBMISSION:**

PART 6. DOWNSTREAM CHARGE CAPACITY AS OF JANUARY 1

Downstream Charge Capacity	Code	2012 Barrels per Calendar Day	2012 Barrels per Stream Day	2013 Barrels per Stream Day
Vacuum Distillation	402		180000	180000
Thermal Cracking:				
Visbreaking	403		0	0
Fluid Coking (incl. Flexicoking)	404	0	0	0
Delayed Coking	405	83600	89300	89000
Other (incl. Gas Oil)	406		0	0
Catalytic Cracking:				
Fresh Feed	407	63600	70000	70000
Recycled	408		5000	5000
Catalytic Hydrocracking:				
Distillate	439	0	0	0
Gas Oil	440	55000	60000	60000
Residual	441	0	0	0
Desulfurization (including Catalytic Hydrotreating):				
Naphtha/Reformer Feed	426		75000	75000
Gasoline	420		42000	42000
Kerosene and Jet	421		40000	40000
Diesel Fuel	422		0	0
Other Distillate	423		45000	45000
Residual	424		49500	49500
Heavy Gas Oil	413		80000	80000
Other	425		43000	43000
Catalytic Reforming:				
Low Pressure	430	42900	45000	45000
High Pressure	431	22700	24500	24500
Fuels Solvent Deasphalting	432			

PART 7. PRODUCTION CAPACITY AS OF JANUARY 1 (Barrels per Stream Day, Except Where Noted)

Production Capacity	Code	2012 Barrels per Stream Day	2013 Barrels per Stream Day
Alkylates	415	18500	18500
Aromatics	437	0	0
Asphalt and Road Oil	931	0	0
Isobutane (C4)	644	0	0
Isopentane (C5), Isohexane (C6)	438	0	0
Isooctane (C8)	635	0	0
Lubricants	854	0	0
Petroleum Coke - Marketable	021	38701	38701
Hydrogen (million cubic ft. per day)	091	108	100
Sulfur (short tons per day)	435	1085	1085

APPENDIX 1.14

ATTACHMENT 3

1

2011 Worldwide Refining Survey

Leena Koottungal
Survey Editor/News Writer

All figures in barrels per calendar day (b/cd)

All figures are as of January 1, 2012

LEGEND
Numbers identify processes in table

Coking
1. Fluid coking
2. Delayed coking
3. Other

Thermal process
1. Thermal cracking
2. Visbreaking

Catalytic cracking
1. Fluid
2. Other

Catalytic reforming
1. Semiregenerative
2. Cyclic
3. Continuous regen.
4. Other

Catalytic hydrocracking
1. Distillate upgrading
2. Residual upgrading
3. Lube oil manufacturing
4. Other

c. Conventional (high pressure) hydrocracking: (>100 barg or 1,450 psig)
m. Mild to moderate hydrocracking (<100 barg or 1,450 psig)

Catalytic hydrotreating
1. Pretreatment of cat reformer feeds
2. Other naphtha desulfurization
3. Naphtha aromatics saturation
4. Kerosine/jet desulfurization
5. Diesel desulfurization
6. Distillate aromatics saturation
7. Other distillates
8. Pretreatment of cat cracker feeds
9. Other heavy gas oil hydrotreating
10. Resid hydrotreating
11. Lube oil polishing
12. Post hydrotreating of FCC naphtha
13. Other

Alkylation
1. Sulfuric acid
2. Hydrofluoric acid

Polymerization/Dimerization
1. Polymerization
2. Dimerization

Aromatics
1. BTX
2. Hydrodealkylation
3. Cyclohexane
4. Cumene

Isomerization
1. C_4 feed
2. C_5 feed
3. C_5 and C_6 feed

Oxygenates
1. MTBE
2. ETBE
3. TAME
4. Other

Hydrogen
Production:
1. Steam methane reforming
2. Steam naphtha reforming
3. Partial oxidation
   a. Third-party plant
Recovery:
4. Pressure swing adsorption
5. Cryogenic
6. Membrane
7. Other

NOTES

A New
B Previously listed as Chevron Corp.
C Previously listed asShell U.K. Ltd.
D Previously listed as AGE Refining & Manufacturing
E Previously listed as Murphy Oil USA Inc.
F May convert into a fuel import terminal
G Idled
H Previously listed as Oil Refineries Ltd.
I Previously listed as SK Corp.
J Previously listed as Hyundai Oil Refinery Co.
K Previously listed as Holly Corp.
L New to survey
M Shut down
N Previously listed as Frontier Oil Corp.
O Previously listed as Frontier Refining Inc.
P Previously listed as ConocoPhillips
Q Plans to sell
R Previously listed as Sunoco Inc.
S Plans to convert to a storage facilty
T For sale
U Previously listed as Valero Energy Corp.
V Previously listed as Marathon Petroleum Co. LP
W Previously listed as Shell Deutschland Oil GMBH

Capacity definitions:
Capacity expressed in barrels per calendar day (b/cd) is the maximum number of barrels of input that can be processed during a 24-hour period, after making allowances for the following: (a) Types and grades of inputs to be processed, (b) Types and grades of products to be manufactured, (c) Environmental constraints associated with refinery operations, (d) Scheduled downtime such as mechanical problems, repairs, and slowdown. Capacity expressed in barrels per stream day (b/sd) is the amount a unit can process when running at full capacity under optimal feedstock and product slate conditions. An asterisk (*) beside a refinery location indicates that the number has been converted from b/sd to b/cd using the conversion factor 0.95 for crude and vacuum distillation units and 0.9 for all downstream cracking and conversion units.

Hydrogen:

Hydrogen volumes presented here represent either generation or upgrading to 90+% purity.

Catalytic reforming:
1. Semiregenerative reforming is characterized by shutdown of the reforming unit at specified intervals, or at the operators's convenience, for in situ catalyst regeneration.
2. Cyclic regeneration reforming is characterized by continuous or continual regeneration of catalyst in situ in any one of several reactors that can be isolated from and returned to the reforming operation. This is accomplished without changing feed rate or octane.
3. Continuous regeneration reforming is characterized by the continuous addition of this regenerated catalyst to the reactor.
4. "Other" includes nonregenerative reforming (catalyst is replaced by fresh catalyst) and moving-bed catalyst systems.

REFINERY REMOVALS

Name	Location	Country	Crude b/cd	Reason
Western Refining	Yorktown, Virginia	US	70,000	Shut down
Sunoco Inc.	Westville, NJ	US	150,000	Shut down
Alon USA	Bakersfield, Calif.	US	70,000	Integrated with Paramount refinery
Holly Corp.	Tulsa, Okla.	US	85,000	Integrated with other Tulsa refinery
Total SA	Dunkirk	France	137,028	Shut down
Pak-Arab Refinery Co.	Mahmood Kot, Punjab	Pakistan	100,000	Shut down
Petroplus Holdings AG	Cressier	Switzerland	60,000	Shut down

Oil & Gas Journal / Dec. 5, 2011

Worldwide Refineries—Capacities as of Jan. 1, 2012

Country	No. of refineries	Crude	Charge capacity, b/cd: Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd: Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (tonnes per day)	Sulfur (tonnes per day)	Asphalt
Albania	2	26,300	10,500	12,000	—	—	3,500	—	17,400	—	—	600	—	700	—	6.5	700	60	—
Algeria	4	450,000	10,894	—	—	—	88,900	—	81,950	—	—	—	—	—	—	—	—	—	—
Angola	1	39,000	2,500	—	—	—	1,900	—	6,600	—	—	—	—	—	—	—	—	—	950
Argentina	10	630,575	248,365	91,233	38,420	141,180	56,630	17,000	175,600	4,300	520	—	12,700	7,290	2,600	19.0	3,810	108	12,700
Aruba	1	235,000	166,250	68,400	30,600	—	—	—	214,200	—	—	—	—	—	—	93.0	4,500	810	—
Australia	7	760,148	192,865	—	—	235,043	172,053	18,407	543,531	24,734	10,609	1,000	39,606	—	—	72.3	—	194	10,017
Austria	1	208,600	65,000	—	16,875	26,250	32,725	—	139,400	—	—	—	14,400	—	1,600	—	—	180	1,470
Azerbaijan	2	398,978	137,200	38,529	—	57,750	24,466	—	67,492	930	—	—	—	16,200	—	—	1,400	—	5,000
Bahrain	1	253,650	198,170	—	21,600	35,100	13,500	54,000	76,500	—	3,330	—	—	—	—	164.0	—	340	8,730
Bangladesh	1	33,000	4,000	—	10,000	—	1,800	1,200	2,000	—	—	—	—	—	—	2.0	—	—	—
Belarus	2	493,323	105,800	—	60,000	44,000	92,000	30,000	262,100	—	—	2,785	4,500	3,760	—	22.8	—	85	9,630
Belgium	4	739,821	250,630	—	30,016	133,553	105,589	—	687,755	17,630	—	—	0	—	3,764	98.5	0	971	26,500
Bolivia	2	41,200	2,200	—	—	—	12,100	—	6,899	—	—	—	—	—	—	14.0	—	—	—
Brazil	13	1,917,333	810,140	115,319	9,800	505,287	24,386	—	284,446	6,290	—	—	—	20,009	6,460	126.0	6,974	771	27,100
Brunei	1	8,600	—	—	—	—	5,700	—	—	—	—	—	—	—	—	—	—	—	—
Bulgaria	1	115,240	49,900	—	20,600	23,300	4,060	—	64,200	2,600	—	2,000	—	—	790	10.3	—	63	1,500
Cameroon	1	37,000	—	—	—	—	6,500	—	16,140	—	—	—	—	—	—	—	—	—	—
Canada	17	1,918,455	645,056	59,100	121,430	482,468	354,930	210,374	1,383,536	70,403	19,240	62,689	62,490	3,000	—	461.0	2,635	2,174	66,000
Chile	3	226,800	85,050	13,860	13,860	50,540	26,460	50,400	—	910	—	—	8,510	—	1,580	—	656	90	—
China	54	6,866,000	240,000	156,000	—	588,000	178,000	185,000	541,000	15,500	—	21,000	—	18,000	900	—	4,020	1,362	—
China, Taiwan	4	1,310,000	248,500	51,000	—	217,900	115,000	25,000	672,500	14,200	—	14,000	26,000	15,300	11,266	341.0	4,522	3,745	15,270
Colombia	5	290,850	141,000	—	52,000	90,000	—	—	19,800	2,100	2,100	2,200	—	1,400	—	18.0	—	—	—
Congo (Brazzaville)	1	21,000	8,000	—	—	—	2,000	2,000	3,500	—	—	—	—	—	—	—	—	—	—
Costa Rica	1	24,000	600	—	6,500	—	1,200	—	2,000	—	—	—	—	—	—	—	—	—	—
Croatia	3	250,317	87,040	5,000	23,526	51,002	49,368	12,264	68,256	—	—	9,438	5,431	470	—	—	200	123	—
Cuba	4	301,400	75,700	—	—	14,700	20,000	—	55,850	—	—	—	—	—	—	5.0	—	—	1,080
Czech Republic	3	183,000	78,870	—	17,000	—	27,470	34,430	103,780	—	—	660	7,210	2,180	2,160	112.0	—	144	10,880
Denmark	2	174,400	22,000	—	64,550	—	21,990	—	42,760	—	—	—	6,400	—	—	—	—	—	8,000
Dominican Republic	2	50,000	—	—	—	—	8,200	—	20,813	—	—	—	—	—	—	0.6	—	—	—
Ecuador	3	176,000	45,300	—	31,500	18,000	12,800	—	24,500	—	—	—	—	—	—	—	—	—	—
Egypt	9	726,250	95,200	39,270	—	—	62,240	33,500	207,802	9,000	—	1,584	10,700	4,441	—	62.5	1,601	290	4,623
El Salvador	1	22,000	4,000	—	—	—	3,000	—	15,500	—	—	—	—	—	—	—	—	—	—
Eritrea	1	14,564	2,219	—	—	—	1,465	—	2,742	—	—	—	—	—	—	—	—	—	—
Finland	2	260,575	146,085	—	34,420	56,690	50,060	90,110	298,325	7,750	600	—	—	5,280	5,730	160.0	—	540	6,800
France	12	1,718,803	715,200	—	146,872	347,052	256,669	71,845	1,233,048	26,702	2,968	2,887	48,492	36,390	4,711	132.0	—	1,383	43,502
Gabon	1	24,000	—	—	9,220	—	1,400	—	9,430	—	—	—	—	—	—	—	—	—	—
Germany	15	2,417,162	1,096,231	105,809	247,445	349,171	404,822	203,067	2,011,782	30,885	8,301	71,944	94,226	14,220	13,172	772.0	3,813	2,914	60,630
Ghana	1	45,000	—	—	—	14,000	65,000	—	—	—	—	—	—	—	—	—	—	—	—
Greece	4	423,000	152,000	—	49,000	75,550	49,200	43,900	361,635	2,400	1,720	9,100	23,650	3,500	3,940	23.5	—	519	16,950
Hungary	1	161,000	77,500	16,900	14,000	24,000	29,600	—	120,700	3,300	—	12,000	3,500	6,100	1,200	76.2	600	226	6,300
India	21	4,042,761	811,986	169,625	93,180	531,305	51,673	165,600	250,742	85,000	—	9,742	—	8,240	1,396	132.9	6,480	452	37,768
Indonesia	8	1,011,825	265,980	32,580	58,860	101,450	92,970	99,720	23,430	16,200	—	—	—	—	—	—	—	—	—
Iran	9	1,451,000	559,400	—	290,800	35,000	164,700	136,500	183,160	—	—	—	—	19,600	—	286.0	—	470	36,500
Iraq	9	637,500	145,000	—	—	—	88,000	74,241	292,000	—	—	—	2,500	9,420	—	64.0	—	—	38,738
Ireland	1	71,000	—	—	—	—	11,000	—	44,600	—	—	—	7,600	—	—	10.3	—	4	—
Israel	2	220,000	118,000	—	66,000	49,500	26,500	—	96,000	—	2,200	—	—	—	750	—	—	—	2,700
Italy	17	2,337,229	814,237	45,000	448,204	321,500	287,069	303,210	1,250,753	40,330	1,500	13,400	112,260	24,000	11,720	305.4	2,046	1,776	15,706
Ivory Coast	1	63,990	23,990	—	—	—	12,330	14,480	27,310	—	—	—	—	—	—	—	—	—	4,330
Jamaica	1	36,000	1,800	—	—	—	3,700	—	23,800	—	—	—	—	—	—	—	—	—	850
Japan	30	4,729,890	1,764,195	123,400	20,000	986,980	829,225	181,690	5,016,160	74,690	5,760	207,467	31,350	38,013	2,978	1,459.4	1,863	9,544	84,370
Jordan	1	90,400	21,500	—	—	4,000	10,900	5,220	17,300	—	—	—	—	—	—	16.0	—	—	4,250
Kazakhstan	3	345,093	121,037	24,997	52,071	38,356	51,586	—	177,890	—	—	—	—	—	—	21.5	1,000	124	8,550
Kenya	1	90,000	1,700	—	—	—	8,260	—	36,000	—	—	—	—	—	—	—	—	—	1,000
Kuwait	3	936,000	327,750	72,000	—	36,000	46,620	115,650	588,780	5,616	—	—	—	—	6,561	741.6	2,800	4,200	—
Kyrgyzstan	1	10,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Liberia	1	15,000	1,000	—	—	—	2,000	—	3,300	—	—	—	—	—	—	—	—	—	200
Libya	5	378,000	3,775	—	—	—	20,250	—	43,330	—	—	—	—	635	—	—	—	—	3,432
Lithuania	1	190,000	89,300	—	28,800	43,200	45,900	—	153,900	—	7,200	—	18,900	—	2,700	25.0	—	320	—
Macedonia	1	50,000	—	—	—	—	10,860	—	22,050	—	—	—	4,390	—	—	—	—	—	—
Malaysia	7	538,582	94,335	24,000	—	42,700	75,070	36,000	216,800	—	—	—	10,800	—	—	147.2	2,245	460	24,700

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Worldwide Refineries—Capacities as of Jan. 1, 2012

			Charge capacity, b/cd								Production capacity, b/cd								
Country	No. of refineries	Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (tonnes per day)	Sulfur (tonnes per day)	Asphalt
Martinique	1	17,329	—	—	—	—	2,862	—	14,269	—	—	—	—	—	—	—	—	—	—
Mexico	6	1,540,000	754,000	191,000	—	380,500	279,300	—	926,050	128,456	—	17,000	—	16,600	15,490	183.0	—	—	58,000
Morocco	2	154,901	24,921	—	—	5,040	24,359	—	35,539	—	—	—	—	2,460	—	—	—	—	5,630
Myanmar	3	57,000	4,000	5,200	—	—	—	—	—	—	—	—	—	500	—	—	120	—	—
Netherlands	6	1,196,571	711,095	41,500	91,404	101,983	148,616	198,071	1,016,234	15,450	—	68,968	8,730	11,600	2,715	358.9	—	1,726	16,500
Netherlands Antilles	1	320,000	195,000	—	80,000	50,000	20,000	—	119,500	9,000	2,000	—	—	12,000	—	54.6	—	300	26,000
New Zealand	1	107,000	38,270	—	—	—	25,840	30,000	104,490	—	—	—	—	—	—	60.0	—	111	5,490
Nicaragua	1	20,000	1,500	—	—	—	3,000	—	14,500	—	—	—	—	—	—	—	—	—	—
Nigeria	4	445,000	124,490	—	—	82,700	70,070	—	109,231	9,870	2,274	291	3,610	3,878	—	—	—	—	14,850
North Korea	2	71,000	—	—	—	—	7,300	—	7,400	—	—	1,000	—	—	1,000	—	—	—	—
Norway	2	319,000	—	24,780	32,000	49,000	34,900	—	126,000	—	11,000	—	3,840	—	—	—	610	20	—
Oman	1	85,000	—	—	—	—	16,000	—	21,000	—	—	—	—	—	—	—	—	—	—
Pakistan	6	186,306	19,815	—	—	—	11,650	—	54,870	—	—	1,400	—	3,800	—	—	—	—	4,200
Papua New Guinea	1	32,500	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Paraguay	1	7,500	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Peru	6	198,950	94,000	—	25,700	33,500	2,100	—	2,800	—	—	—	—	—	—	—	—	—	3,800
Philippines	3	273,000	61,000	—	33,000	19,000	51,000	—	184,990	—	—	—	10,000	3,700	—	37.0	—	70	1,200
Poland	4	492,950	265,123	—	—	32,985	67,514	145,908	259,507	3,372	—	10,262	23,194	17,796	2,514	167.0	—	560	33,371
Portugal	2	304,172	87,785	—	36,540	40,500	50,182	9,180	201,537	5,400	—	17,276	—	—	—	85.3	—	252	—
Puerto Rico	1	73,000	34,000	—	—	—	21,000	20,000	21,000	—	—	—	—	—	—	20.0	—	34	—
Qatar	2	338,700	—	—	—	60,000	29,400	20,000	39,350	—	—	—	25,000	—	—	—	—	—	—
Romania	10	537,277	273,225	68,240	37,577	109,478	61,763	1,534	237,625	2,300	—	7,801	3,846	10,366	1,330	18.0	2,555	143	13,761
Russia	40	5,430,908	2,028,570	84,999	382,593	330,817	745,735	57,056	2,170,966	10,006	1,729	54,337	21,869	82,842	7,175	93.3	3,720	726	210,545
Saudi Arabia	7	2,112,000	445,950	—	138,200	103,600	193,160	133,820	493,460	31,500	—	6,500	33,000	—	3,700	190.7	—	—	—
Senegal	1	25,030	7,160	—	—	—	1,590	—	1,930	—	—	—	—	—	—	—	—	—	—
Serbia & Montenegro	2	214,826	50,583	—	20,340	18,950	18,822	—	50,910	3,070	—	200	—	300	—	0.5	—	59	2,400
Sierra Leone	1	10,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Singapore	3	1,357,000	346,000	—	203,710	80,000	146,470	129,360	706,500	9,000	—	48,000	—	45,500	1,400	275.0	—	845	39,500
Slovakia	1	115,000	55,000	—	—	18,000	21,000	42,000	87,800	4,500	—	9,250	6,000	2,000	1,500	89.6	—	270	2,600
Slovenia	1	13,500	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
South Africa	4	484,547	201,375	26,800	60,000	108,640	77,142	11,774	227,772	9,595	4,940	6,900	12,223	8,000	—	50.2	240	607	7,100
South Korea	6	2,759,500	515,650	19,000	—	314,000	342,000	326,500	1,450,380	48,700	—	140,300	—	66,640	10,500	1,385.5	1,200	4,730	81,327
Spain	9	1,271,500	414,245	61,100	149,200	191,300	196,750	131,500	825,380	16,916	—	25,800	36,000	9,600	9,600	300.1	3,565	1,762	26,600
Sri Lanka	1	50,000	24,000	—	12,500	—	5,300	—	19,295	—	—	—	—	—	—	—	—	—	1,000
Sudan	3	121,700	—	—	—	—	1,900	—	8,100	—	—	—	—	—	—	—	—	—	—
Suriname	1	7,000	7,000	—	2,800	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sweden	5	437,000	135,600	—	66,800	29,700	70,660	48,600	268,540	—	3,420	—	28,530	—	—	53.8	—	334	27,460
Switzerland	1	72,000	—	—	—	20,400	12,000	—	33,200	—	3,800	—	6,400	—	—	28.0	—	—	—
Syria	2	239,865	63,135	18,200	22,689	—	31,242	26,410	80,886	—	—	—	11,493	—	—	27.0	500	150	2,223
Tanzania	1	14,900	—	—	2,500	—	2,500	—	4,400	—	—	—	—	—	—	—	—	—	—
Thailand	4	584,250	202,500	—	16,983	91,990	97,770	43,073	428,630	—	—	9,500	19,596	—	—	33.5	—	420	2,500
Trinidad & Tobago	1	168,000	119,200	—	24,000	24,000	18,000	45,000	41,000	1,200	1,580	—	—	—	1,000	30.0	—	100	—
Tunisia	1	34,000	—	—	—	—	3,300	—	—	—	—	—	—	—	—	—	—	—	—
Turkey	6	714,275	201,767	—	23,590	28,935	65,662	53,820	265,005	—	—	—	14,055	5,870	—	217.5	180	315	20,216
Turkmenistan	2	236,970	91,645	28,568	—	15,151	52,540	—	63,500	1,028	1,223	—	—	2,000	—	—	1,040	—	415
Ukraine	6	879,759	336,297	22,149	17,291	70,100	144,711	7,200	315,013	—	—	3,464	—	500	125	21.5	705	176	12,785
United Arab Emirates	5	773,250	92,870	—	—	34,350	25,875	31,050	158,627	1,140	1,900	—	—	—	—	58.8	—	57	700
United Kingdom	10	1,767,168	866,314	64,600	106,958	444,723	339,771	36,000	1,271,541	92,202	13,596	14,590	120,423	23,899	3,967	127.0	2,400	792	28,430
United States	125	17,787,714	7,909,865	2,543,298	34,020	5,649,659	3,492,288	1,726,030	14,061,515	1,142,127	74,810	464,639	678,777	193,100	32,250	4,044.9	131,073	32,284	490,817
Uruguay	1	50,000	25,000	—	7,000	12,000	12,000	—	23,000	—	—	—	6,000	—	—	—	—	—	—
Uzbekistan	3	224,271	45,671	17,667	9,585	—	23,487	—	30,804	—	—	—	—	9,397	—	—	650	—	4,151
Venezuela	5	1,282,100	585,780	144,900	—	231,800	49,500	—	389,700	65,800	—	2,000	20,700	12,020	12,830	147.8	5,200	1,471	36,000
Vietnam	1	140,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Virgin Islands	1	500,000	205,000	55,000	37,000	140,000	105,000	—	435,000	18,000	7,000	18,000	17,000	—	—	—	3,500	500	—
Yemen	2	140,000	10,500	—	—	—	14,500	—	—	—	—	—	—	—	—	—	—	—	3,000
Zambia	1	23,750	2,280	—	—	—	5,320	—	8,550	—	—	—	—	—	—	—	—	—	5,527
Total	655	88,055,552	29,062,130	4,681,023	3,801,129	14,693,328	11,468,147	5,488,694	45,730,072	2,090,102	195,320	1,371,975	1,665,901	802,516	193,074	14,160	209,123	83,256	1,794,824

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APPENDICES TO CONSENT DECREE

APPENDIX 2.1

COVERED FLARES AND APPLICABILITY DATES FOR CERTAIN CONSENT DECREE REQUIREMENTS

APPENDIX 2.1 -- Covered Flares and Applicability Dates for Certain Consent Decree Requirements

FLARE	FLARE DATA AND MONITORING SYSTEMS AND PROTOCOL REPORT	INSTALLATION AND OPERATION OF MONITORING SYSTEMS AND EXIT VELOCITY REQUIREMENTS	INITIAL WASTE GAS MINIMIZATION PLAN	FIRST UPDATED WASTE GAS MINIMIZATION PLAN	GENERAL EMISSION STANDARDS FOR COVERED FLARES	WORK PRACTICE STANDARDS FOR COVERED FLARES	SPECIFIC EMISSION STANDARDS FOR COVERED FLARES
				\			
A	B	C	D	E	F	G	H
-- REFERENCED PARAGRAPHS --							
12.s	16	17, 51	30	31	50	53	55, 56.b-59
East Property	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	DOE	DOE + 365 days
Coker	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	DOE	6/30/2014
Girbotol	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	DOE	DOE + 365 days
North Property	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	DOE	DOE + 365 days
West Property	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	DOE	6/30/2014
Olefins Ground	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	DOE	DOE + 365 days
Olefins II	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	PARA. 53.a.i 06/30/2016 PARA. 53.a.ii DOE	DOE + 365 days
Olefins III	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	PARA. 53.a.i 06/30/2018 PARA. 53.a.ii DOE	DOE + 365 days
HIPA	DOE + 365 days	12/31/2013	DOE + 365 days	DOE + 730 days	DOE	DOE	DOE + 365 days
South Property (Temporary-Use)	Prior to receipt of Vent Gas after DOE	Upon receipt of Vent Gas after DOE	N/A	N/A	DOE	Upon receipt of Vent Gas after DOE	Upon receipt of Vent Gas after DOE
CCU (Temporary-Use)	Prior to receipt of Vent Gas after DOE	Upon receipt of Vent Gas after DOE	N/A	N/A	DOE	Upon receipt of Vent Gas after DOE	Upon receipt of Vent Gas after DOE
A&S (Temporary-Use)	Prior to receipt of Vent Gas after 6/30/2013	Upon receipt of Vent Gas after 6/30/2013	N/A	N/A	DOE	Upon receipt of Vent Gas after 6/30/2013	Upon receipt of Vent Gas after 6/30/2013

Legend:
DOE = Date of Entry

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APPENDICES TO CONSENT DECREE

APPENDIX 2.2

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APPENDICES TO CONSENT DECREE

APPENDIX 2.3

METHODOLOGY FOR CALCULATING REFINERY FLARING LIMITATION (INCLUDING SDP'S FORM EIA-820 FOR REPORT YEAR 2012)

APPENDIX 2.3

Refinery	Calculation Basis	Refinery Crude Capacity (b/cd)	Refinery Complexity[2]	US Complexity[2]	Refinery/US Complexity	30-Day Rolling Average SCFD	365-Day Rolling Average SCFD
Shell Deer Park	EIA/O&GJ (b/cd)[1]	327,000	11.33	11.32	1.001	2,455,944	1,637,296

Notes:

1) Data in barrels per calendar day (b/cd) are shown on the next page. US capacities as of 1/1/2012 as taken from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/22/2012) were used preferentially, see Attachment 1, along with the corresponding Shell Deer Park capacities as of 1/1/2012 submitted by Shell Deer Park on Form EIA-820 Annual Refinery Report Parts 5 and 6. See Attachment 2. For processes where US capacities were not included on the US EIA report, Oil & Gas Journal Worldwide Refining Survey (published 12/5/2011) calendar day capacities were used for both the US and Shell Deer Park. See Attachment 3. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.

2) Nelson Complexity factors are shown on the next page, and are specified in CD Appendix 1.14

APPENDIX 2.3

Process	Nelson Complexity Factors	SDP Capacity as of 1/1/2012 (b/cd, except H2 and S)	SDP Capacity as of 1/1/2012 Source (Notes 1, 2 & 3)	US Capacity as of 1/1/2012 (b/cd, except H2 and S)	US Capacity as of 1/1/2012 Source (Notes 1, 2 & 4)
Atmospheric Distillation	1	327,000	Part 5, SDP's 2012 EIA-820, b/cd	17,322,178	EIA Website 2012 Data, b/cd
Vacuum Distillation	1.3	171,000	Part 6, SDP's 2012 EIA-820, b/sd*0.95	8,245,661	EIA Website 2012 Data, b/sd*0.95
Coking	7.5	83,600	Part 6, SDP's 2012 EIA-820, b/cd	2,499,293	EIA Website 2012 Data, b/cd
Catalytic Cracking - Fresh Feed	6	63,600	Part 6, SDP's 2012 EIA-820, b/cd	5,611,191	EIA Website 2012 Data, b/cd
Catalytic Cracking - Recycle Feed	6	4,500	Part 6, SDP's 2012 EIA-820, b/sd*0.9	76,401	EIA Website 2012 Data, b/sd*0.9
Reforming	5	65,600	Part 6, SDP's 2012 EIA-820, b/cd	3,246,874	EIA Website 2012 Data, b/cd
Hydrocracking	8	55,000	Part 6, SDP's 2012 EIA-820, b/cd	1,706,540	EIA Website 2012 Data, b/cd
Hydrotreating	2.5	337,050	Part 6, SDP's 2012 EIA-820, b/sd*0.9	14,908,736	EIA Website 2012 Data, b/sd*0.9
Alkylates	10	17,600	O&GJ (12/5/2011), b/cd	1,142,127	O&GJ (12/5/2011), b/cd
Hydrogen (mmcfd)	1000	92	O&GJ (12/5/2011), mmscf/cd	4,045	O&GJ (12/5/2011), mmscf/cd
Sulfur (short tons/day)	240	1,011	O&GJ (12/5/2011), t/cd	32,284	O&GJ (12/5/2011), t/cd
Thermal Processes (Visbreaking)	2.75	0	Part 6, SDP's 2012 EIA-820, b/sd*0.9	14,400	EIA Website 2012 Data, b/sd*0.9
Polymerization	10	0	O&GJ (12/5/2011), b/cd	74,810	O&GJ (12/5/2011), b/cd
Aromatics	20	0	O&GJ (12/5/2011), b/cd	464,639	O&GJ (12/5/2011), b/cd
Isomerization	3	0	O&GJ (12/5/2011), b/cd	678,777	O&GJ (12/5/2011), b/cd
Oxygenates	10	0	O&GJ (12/5/2011), b/cd	32,250	O&GJ (12/5/2011), b/cd
Lubes	60	0	O&GJ (12/5/2011), b/cd	193,100	O&GJ (12/5/2011), b/cd
Asphalt	1.5	0	O&GJ (12/5/2011), b/cd	490,817	O&GJ (12/5/2011), b/cd
Refinery / US Complexity		**11.33**		**11.32**	

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2012 from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/22/2012 and available at www.eia.gov) were used preferentially, see Attachment 1, along with the corresponding Shell Deer Park capacities as of 1/1/2012 submitted by Shell Deer Park on Form EIA-820 Annual Refinery Report Parts 5 and 6, see Attachment 2. For processes where US capacities were not included on the US EIA report (i.e. those reported in Part 7 of EIA-820 rather than Part 6), Oil & Gas Journal Worldwide Refining Survey (published 12/5/2011) calendar day capacities were used for both the US and Shell Deer Park, see Attachment 3. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.

Note 2: O&GJ (12/5/2011) = Oil & Gas Journal Worldwide Refining Survey (published 12/5/2011) of petroleum refinery capacities as of 1/1/2012. See Attachment 3.

Note 3: Part 5 or 6, SDP 2012 EIA-820 = U.S. Energy Information Administration Form EIA-820 submitted by Shell Deer Park. See Attachment 2.

Note 4: EIA Website 2012 Data = US Energy Information Administration Website (www.eia.gov), Number and Capacity of Petroleum Refineries data for the year 2012. See Attachment 1.

APPENDIX 2.3

ATTACHMENT 1

U.S. Energy Information Administration

PETROLEUM & OTHER LIQUIDS

OVERVIEW DATA ANALYSIS & PROJECTIONS GLOSSARY › FAQS ›

Number and Capacity of Petroleum Refineries

Area: U.S. **Period:** Annual (as of January 1)

Show Data By: Data Series Area	Graph Clear	2007	2008	2009	2010	2011	2012	View History
Number of Operable Refineries								
Total Number of Operable Refineries		149	150	150	148	148	144	1982-2012
Operating		145	146	141	137	137	134	1982-2012
Idle		4	4	9	11	11	10	1982-2012
Atmospheric Crude Oil Distillation Capacity								
Operable (Barrels per Calendar Day)		17,443,492	17,593,847	17,671,550	17,583,790	17,736,370	17,322,178	1982-2012
Operating		16,997,792	17,225,797	17,313,550	16,850,194	16,937,024	16,744,291	1982-2012
Idle		445,700	368,050	358,000	733,596	799,346	577,887	1982-2012
Operable (Barrels per Stream Day)		18,425,322	18,558,022	18,681,308	18,581,089	18,953,189	18,560,350	1982-2012
Operating		17,928,522	18,174,072	18,300,358	17,808,082	18,109,882	17,945,443	1982-2012
Idle		496,800	383,950	380,950	773,007	843,307	614,907	1982-2012
Downstream Charge Capacity (Barrels per Stream Day)								
Vacuum Distillation		8,251,451	8,420,501	8,542,281	8,542,643	8,650,243	8,679,643	1982-2012
Thermal Cracking		2,564,080	2,606,260	2,639,090	2,631,676	2,672,376	2,763,356	1982-2012
Total Coking		2,537,480	2,579,660	2,612,490	2,605,076	2,645,776	2,736,756	1987-2012
Delayed Coking		2,331,580	2,374,260	2,454,590	2,500,676	2,486,876	2,577,856	1987-2012
Fluid Coking		205,900	205,400	157,900	104,400	158,900	158,900	1987-2012
Visbreaking		16,000	16,000	16,000	16,000	16,000	16,000	1987-2012
Other (Including Gas Oil)		10,600	10,600	10,600	10,600	10,600	10,600	1987-2012
Catalytic Cracking - Fresh Feed		6,218,957	6,265,697	6,291,871	6,140,121	6,219,721	6,032,512	1982-2012
Catalytic Cracking - Recycle Feed		82,040	78,740	78,740	91,840	95,640	84,890	1982-2012
Catalytic Hydro-Cracking		1,790,682	1,770,325	1,743,300	1,819,700	1,855,600	1,879,600	1982-2012
Distillate		602,800	556,900	593,100	595,200	540,100	596,500	2004-2012
Gas Oil		987,482	1,004,425	1,010,200	1,079,500	1,170,500	1,161,100	2004-2012
Residual		200,400	209,000	140,000	145,000	145,000	122,000	2004-2012
Catalytic Reforming		3,907,510	3,891,938	3,829,338	3,700,463	3,720,613	3,641,813	1982-2012
Low Pressure		2,354,950	2,402,350	2,397,750	2,322,700	2,390,950	2,347,850	1987-2012
High Pressure		1,552,560	1,489,588	1,431,588	1,377,763	1,329,663	1,293,963	1987-2012
Catalytic Hydrotreating/Desulfurization		15,447,136	15,807,478	16,130,823	16,023,206	16,682,897	16,565,262	1982-2012
Naphtha/Reformer Feed		4,453,890	4,348,590	4,334,297	4,281,046	4,441,323	4,360,593	1987-2012
Gasoline		2,221,568	2,420,968	2,415,282	2,394,882	2,578,782	2,519,082	2004-2012
Heavy Gas Oil		2,578,840	2,672,440	2,735,538	2,796,798	2,809,298	2,877,138	1987-2012
Distillate Fuel Oil		5,212,387	5,462,649	5,622,252	5,676,032	6,113,846	6,063,001	1987-2012
Kerosene/Jet Fuel		1,009,450	1,137,010	1,160,110	1,339,150	1,484,850	1,489,750	2004-2012
Diesel Fuel		3,332,671	3,468,471	3,551,211	3,647,211	3,917,611	3,981,411	2004-2012
Other Distillate		870,266	857,168	910,931	689,671	711,385	591,840	2004-2012
Residual Fuel Oil/Other		980,451	902,831	1,023,454	874,448	739,648	745,448	1987-2012
Residual Fuel Oil		331,420	251,200	316,400	246,200	241,000	246,000	2004-2012
Other		649,031	651,631	707,054	628,248	498,648	499,448	2004-2012

Fuels Solvent Deasphalting		379,290	378,350	380,950	383,250	382,750	374,550	1987-2012
Downstream Charge Capacity (Barrels per Calendar Day)								
Catalytic Reforming					3,378,841	3,346,457	3,246,874	2010-2012
Total Coking		2,359,318	2,390,223	2,428,961	2,387,896	2,396,787	2,499,293	1987-2012
Catalytic Cracking - Fresh Feed		5,830,486	5,853,656	5,847,130	5,675,830	5,794,214	5,611,191	1987-2012
Catalytic Hydro-Cracking		1,620,705	1,602,431	1,592,973	1,663,115	1,687,745	1,706,540	1987-2012

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Notes: Idle refineries represent refineries where distillation units were completely idle but not permanently shutdown as of January 1 of the year. See Definitions, Sources, and Notes link above for more information on this table.

Release Date: 6/22/2012
Next Release Date: 6/21/2013

APPENDIX 2.3

ATTACHMENT 2

U.S. Energy Information Administration

OMB No. 1905-0165
Expiration Date: 1/31/2013
Version No.:2010.02

FORM EIA-820
ANNUAL REFINERY REPORT
REPORT YEAR 2012

This report is **mandatory** under the Federal Energy Administration Act of 1974 (Public Law 93-275). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning the confidentiality of information in the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly makes to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

PART 1. RESPONDENT IDENTIFICATION DATA

EIA ID NUMBER: 1339570101

If any Respondent Identification Data has changed since the last report, enter an "X" in the box: ☐

Company Name: Shell Oil Co.
Doing Business As:
Site Name: DEER PARK REFG LTD PTNRSHP
Terminal Control Number (TCN):

Physical Address (e.g., Street Address, Building Number, Floor, Suite):
HWY 225
City DEER PARK State: TX Zip: 77536 - 0100

Mailing Address of Contact (e.g., PO Box, RR): If the physical and mailing addresses are the same, only complete the physical address.
P.O. BOX 100
City DEER PARK State: TX Zip: 77536 - 0100

Contact Name: [redacted]
Phone No.: [redacted] Ext: [redacted]
Fax No.: [redacted]
Email address: [redacted]

PART 2. SUBMISSION/RESUBMISSION INFORMATION

If this is a resubmission, enter an "X" in the box: ☐

A completed form must be received by February 15th of the designated report year.

Forms may be submitted using one of the following methods:

Email: OOG.SURVEYS@eia.gov

Fax: (202) 586-1076

Secure File Transfer:
https://signon.eia.doe.gov/upload/noticeoog.jsp

Questions? Call: 202-586-6281

Comments: Explain any unusual or substantially different aspects of your current year's operations that affect the data reported. For example, note new processing units, major modifications or retirement of processing units, sale of refinery, etc. (To separate one comment from another, press ALT+ENTER)

eia U.S. Energy Information Administration

OMB No. 1905-0165
Expiration Date: 1/31/2013
Version No.:2010.02

FORM EIA-820
ANNUAL REFINERY REPORT
REPORT YEAR 2012

EIA ID NUMBER: 1339570101 **RESUBMISSION:**

PART 3. FUEL, ELECTRICITY, AND STEAM PURCHASED & CONSUMED AT THE REFINERY DURING 2011

REDACTED

PART 5. ATMOSPHERIC CRUDE OIL DISTILLATION CAPACITY AS OF JANUARY 1

Atmospheric Crude Oil Distillation Capacity	Code	Barrel per Calendar Day[2]	Barrels per Stream Day
2012: Operating	399	327000	327000
Idle	400	0	0
Total Operable	401	327000	327000
2013: Operable	501		327000

[2] Barrels per Calendar Day Operating, Idle and Total Operable Capacity (Codes 399, 400 and 401) **must match** the comparable capacity numbers reported on the Form EIA-810, "Monthly Refinery Report," filed for January 2012.

eia Independent Statistics & Analysis
U.S. Energy Information Administration

OMB No. 1905-0165
Expiration Date: 1/31/2013
Version No.:2010.02

FORM EIA-820
ANNUAL REFINERY REPORT
REPORT YEAR 2012

EIA ID NUMBER: 1339570101 **RESUBMISSION:**

PART 6. DOWNSTREAM CHARGE CAPACITY AS OF JANUARY 1

Downstream Charge Capacity	Code	2012 Barrels per Calendar Day	2012 Barrels per Stream Day	2013 Barrels per Stream Day
Vacuum Distillation	402		180000	180000
Thermal Cracking:				
Visbreaking	403		0	0
Fluid Coking (incl. Flexicoking)	404	0	0	0
Delayed Coking	405	83600	89300	89000
Other (incl. Gas Oil)	406		0	0
Catalytic Cracking:				
Fresh Feed	407	63600	70000	70000
Recycled	408		5000	5000
Catalytic Hydrocracking:				
Distillate	439	0	0	0
Gas Oil	440	55000	60000	60000
Residual	441	0	0	0
Desulfurization (including Catalytic Hydrotreating):				
Naphtha/Reformer Feed	426		75000	75000
Gasoline	420		42000	42000
Kerosene and Jet	421		40000	40000
Diesel Fuel	422		0	0
Other Distillate	423		45000	45000
Residual	424		49500	49500
Heavy Gas Oil	413		80000	80000
Other	425		43000	43000
Catalytic Reforming:				
Low Pressure	430	42900	45000	45000
High Pressure	431	22700	24500	24500
Fuels Solvent Deasphalting	432			

PART 7. PRODUCTION CAPACITY AS OF JANUARY 1 (Barrels per Stream Day, Except Where Noted)

Production Capacity	Code	2012 Barrels per Stream Day	2013 Barrels per Stream Day
Alkylates	415	18500	18500
Aromatics	437	0	0
Asphalt and Road Oil	931	0	0
Isobutane (C4)	644	0	0
Isopentane (C5), Isohexane (C6)	438	0	0
Isooctane (C8)	635	0	0
Lubricants	854	0	0
Petroleum Coke - Marketable	021	38701	38701
Hydrogen (million cubic ft. per day)	091	108	100
Sulfur (short tons per day)	435	1085	1085

APPENDIX 2.3

ATTACHMENT 3

1

2011 Worldwide Refining Survey

Leena Koottungal
Survey Editor/News Writer

All figures in barrels per calendar day (b/cd)

All figures are as of January 1, 2012

LEGEND
Numbers identify processes in table

Coking
1. Fluid coking
2. Delayed coking
3. Other

Thermal process
1. Thermal cracking
2. Visbreaking

Catalytic cracking
1. Fluid
2. Other

Catalytic reforming
1. Semiregenerative
2. Cyclic
3. Continuous regen.
4. Other

Catalytic hydrocracking
1. Distillate upgrading
2. Residual upgrading
3. Lube oil manufacturing
4. Other
c. Conventional (high pressure) hydrocracking: (>100 barg or 1,450 psig)
m. Mild to moderate hydrocracking (<100 barg or 1,450 psig)

Catalytic hydrotreating
1. Pretreatment of cat reformer feeds
2. Other naphtha desulfurization
3. Naphtha aromatics saturation
4. Kerosine/jet desulfurization
5. Diesel desulfurization
6. Distillate aromatics saturation
7. Other distillates
8. Pretreatment of cat cracker feeds
9. Other heavy gas oil hydrotreating
10. Resid hydrotreating
11. Lube oil polishing
12. Post hydrotreating of FCC naphtha
13. Other

Alkylation
1. Sulfuric acid
2. Hydrofluoric acid

Polymerization/Dimerization
1. Polymerization
2. Dimerization

Aromatics
1. BTX
2. Hydrodealkylation
3. Cyclohexane
4. Cumene

Isomerization
1. C_4 feed
2. C_5 feed
3. C_5 and C_6 feed

Oxygenates
1. MTBE
2. ETBE
3. TAME
4. Other

Hydrogen
Production:
1. Steam methane reforming
2. Steam naphtha reforming
3. Partial oxidation
   a. Third-party plant

Recovery:

4. Pressure swing adsorption
5. Cryogenic
6. Membrane
7. Other

NOTES

A New
B Previously listed as Chevron Corp.
C Previously listed asShell U.K. Ltd.
D Previously listed as AGE Refining & Manufacturing
E Previously listed as Murphy Oil USA Inc.
F May convert into a fuel import terminal
G Idled
H Previously listed as Oil Refineries Ltd.
I Previously listed as SK Corp.
J Previously listed as Hyundai Oil Refinery Co.
K Previously listed as Holly Corp.
L New to survey
M Shut down
N Previously listed as Frontier Oil Corp.
O Previously listed as Frontier Refining Inc.
P Previously listed as ConocoPhillips
Q Plans to sell
R Previously listed as Sunoco Inc.
S Plans to convert to a storage facilty
T For sale
U Previously listed as Valero Energy Corp.
V Previously listed as Marathon Petroleum Co. LP
W Previously listed as Shell Deutschland Oil GMBH

Capacity definitions:
Capacity expressed in barrels per calendar day (b/cd) is the maximum number of barrels of input that can be processed during a 24-hour period, after making allowances for the following: (a) Types and grades of inputs to be processed, (b) Types and grades of products to be manufactured, (c) Environmental constraints associated with refinery operations, (d) Scheduled downtime such as mechanical problems, repairs, and slowdown. Capacity expressed in barrels per stream day (b/sd) is the amount a unit can process when running at full capacity under optimal feedstock and product slate conditions. An asterisk (*) beside a refinery location indicates that the number has been converted from b/sd to b/cd using the conversion factor 0.95 for crude and vacuum distillation units and 0.9 for all downstream cracking and conversion units.

Hydrogen:

Hydrogen volumes presented here represent either generation or upgrading to 90+% purity.

Catalytic reforming:
1. Semiregenerative reforming is characterized by shutdown of the reforming unit at specified intervals, or at the operators's convenience, for in situ catalyst regeneration.
2. Cyclic regeneration reforming is characterized by continuous or continual regeneration of catalyst in situ in any one of several reactors that can be isolated from and returned to the reforming operation. This is accomplished without changing feed rate or octane.
3. Continuous regeneration reforming is characterized by the continuous addition of this regenerated catalyst to the reactor.
4. "Other" includes nonregenerative reforming (catalyst is replaced by fresh catalyst) and moving-bed catalyst systems.

REFINERY REMOVALS

Name	Location	Country	Crude b/cd	Reason
Western Refining	Yorktown, Virginia	US	70,000	Shut down
Sunoco Inc.	Westville, NJ	US	150,000	Shut down
Alon USA	Bakersfield, Calif.	US	70,000	Integrated with Paramount refinery
Holly Corp.	Tulsa, Okla.	US	85,000	Integrated with other Tulsa refinery
Total SA	Dunkirk	France	137,028	Shut down
Pak-Arab Refinery Co.	Mahmood Kot, Punjab	Pakistan	100,000	Shut down
Petroplus Holdings AG	Cressier	Switzerland	60,000	Shut down

Oil & Gas Journal / Dec. 5, 2011

Worldwide Refineries—Capacities as of Jan. 1, 2012

Country	No. of refineries	Crude	Charge capacity, b/cd: Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd: Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (tonnes per day)	Sulfur (tonnes per day)	Asphalt
Albania	2	26,300	10,500	12,000	—	—	3,500	—	17,400	—	—	600	—	700	—	6.5	700	60	—
Algeria	4	450,000	10,894	—	—	—	88,900	—	81,950	—	—	—	—	—	—	—	—	—	—
Angola	1	39,000	2,500	—	—	—	1,900	—	6,600	—	—	—	—	—	—	—	—	—	950
Argentina	10	630,575	248,365	91,233	38,420	141,180	56,630	17,000	175,600	4,300	520	—	12,700	7,290	2,600	19.0	3,810	108	12,700
Aruba	1	235,000	166,250	68,400	30,600	—	—	—	214,200	—	—	—	—	—	—	93.0	4,500	810	—
Australia	7	760,148	192,865	—	—	235,043	172,053	18,407	543,531	24,734	10,609	1,000	39,606	—	—	72.3	—	194	10,017
Austria	1	208,600	65,000	—	16,875	26,250	32,725	—	139,400	—	—	—	14,400	—	1,600	—	—	180	1,470
Azerbaijan	2	398,978	137,200	38,529	—	57,750	24,466	—	67,492	930	—	—	—	16,200	—	—	1,400	—	5,000
Bahrain	1	253,650	198,170	—	21,600	35,100	13,500	54,000	76,500	—	3,330	—	—	—	—	164.0	—	340	8,730
Bangladesh	1	33,000	4,000	—	10,000	—	1,800	1,200	2,000	—	—	—	—	—	—	2.0	—	—	—
Belarus	2	493,323	105,800	—	60,000	44,000	92,000	30,000	262,100	—	—	2,785	4,500	3,760	—	22.8	—	85	9,630
Belgium	4	739,821	250,630	—	30,016	133,553	105,589	—	687,755	17,630	—	—	0	—	3,764	98.5	0	971	26,500
Bolivia	2	41,200	2,200	—	—	—	12,100	—	6,899	—	—	—	—	—	—	14.0	—	—	—
Brazil	13	1,917,333	810,140	115,319	9,800	505,287	24,386	—	284,446	6,290	—	—	—	20,009	6,460	126.0	6,974	771	27,100
Brunei	1	8,600	—	—	—	—	5,700	—	—	—	—	—	—	—	—	—	—	—	—
Bulgaria	1	115,240	49,900	—	20,600	23,300	4,060	—	64,200	2,600	—	2,000	—	—	790	10.3	—	63	1,500
Cameroon	1	37,000	—	—	—	—	6,500	—	16,140	—	—	—	—	—	—	—	—	—	—
Canada	17	1,918,455	645,056	59,100	121,430	482,468	354,930	210,374	1,383,536	70,403	19,240	62,689	62,490	3,000	—	461.0	2,635	2,174	66,000
Chile	3	226,800	85,050	13,860	13,860	50,540	26,460	50,400	—	910	—	—	8,510	—	1,580	—	656	90	—
China	54	6,866,000	240,000	156,000	—	588,000	178,000	185,000	541,000	15,500	—	21,000	—	18,000	900	—	4,020	1,362	—
China, Taiwan	4	1,310,000	248,500	51,000	—	217,900	115,000	25,000	672,500	14,200	—	14,000	26,000	15,300	11,266	341.0	4,522	3,745	15,270
Colombia	5	290,850	141,000	—	52,000	90,000	—	—	19,800	2,100	2,100	2,200	—	1,400	—	18.0	—	—	—
Congo (Brazzaville)	1	21,000	8,000	—	—	—	2,000	2,000	3,500	—	—	—	—	—	—	—	—	—	—
Costa Rica	1	24,000	600	—	6,500	—	1,200	—	2,000	—	—	—	—	—	—	—	—	—	—
Croatia	3	250,317	87,040	5,000	23,526	51,002	49,368	12,264	68,256	—	—	9,438	5,431	470	—	—	200	123	—
Cuba	4	301,400	75,700	—	—	14,700	20,000	—	55,850	—	—	—	—	—	—	5.0	—	—	1,080
Czech Republic	3	183,000	78,870	—	17,000	—	27,470	34,430	103,780	—	—	660	7,210	2,180	2,160	112.0	—	144	10,880
Denmark	2	174,400	22,000	—	64,550	—	21,990	—	42,760	—	—	—	6,400	—	—	—	—	—	8,000
Dominican Republic	2	50,000	—	—	—	—	8,200	—	20,813	—	—	—	—	—	—	0.6	—	—	—
Ecuador	3	176,000	45,300	—	31,500	18,000	12,800	—	24,500	—	—	—	—	—	—	—	—	—	—
Egypt	9	726,250	95,200	39,270	—	—	62,240	33,500	207,802	9,000	—	1,584	10,700	4,441	—	62.5	1,601	290	4,623
El Salvador	1	22,000	4,000	—	—	—	3,000	—	15,500	—	—	—	—	—	—	—	—	—	—
Eritrea	1	14,564	2,219	—	—	—	1,465	—	2,742	—	—	—	—	—	—	—	—	—	—
Finland	2	260,575	146,085	—	34,420	56,690	50,060	90,110	298,325	7,750	600	—	—	5,280	5,730	160.0	—	540	6,800
France	12	1,718,803	715,200	—	146,872	347,052	256,669	71,845	1,233,048	26,702	2,968	2,887	48,492	36,390	4,711	132.0	—	1,383	43,502
Gabon	1	24,000	—	—	9,220	—	1,400	—	9,430	—	—	—	—	—	—	—	—	—	—
Germany	15	2,417,162	1,096,231	105,809	247,445	349,171	404,822	203,067	2,011,782	30,885	8,301	71,944	94,226	14,220	13,172	772.0	3,813	2,914	60,630
Ghana	1	45,000	—	—	—	14,000	65,000	—	—	—	—	—	—	—	—	—	—	—	—
Greece	4	423,000	152,000	—	49,000	75,550	49,200	43,900	361,635	2,400	1,720	9,100	23,650	3,500	3,940	23.5	—	519	16,950
Hungary	1	161,000	77,500	16,900	14,000	24,000	29,600	—	120,700	3,300	—	12,000	3,500	6,100	1,200	76.2	600	226	6,300
India	21	4,042,761	811,986	169,625	93,180	531,305	51,673	165,600	250,742	85,000	—	9,742	—	8,240	1,396	132.9	6,480	452	37,768
Indonesia	8	1,011,825	265,980	32,580	58,860	101,450	92,970	99,720	23,430	16,200	—	—	—	—	—	—	—	—	—
Iran	9	1,451,000	559,400	—	290,800	35,000	164,700	136,500	183,160	—	—	—	—	19,600	—	286.0	—	470	36,500
Iraq	9	637,500	145,000	—	—	—	88,000	74,241	292,000	—	—	—	2,500	9,420	—	64.0	—	—	38,738
Ireland	1	71,000	—	—	—	—	11,000	—	44,600	—	—	—	7,600	—	—	10.3	—	4	—
Israel	2	220,000	118,000	—	66,000	49,500	26,500	—	96,000	—	2,200	—	—	—	750	—	—	—	2,700
Italy	17	2,337,229	814,237	45,000	448,204	321,500	287,069	303,210	1,250,753	40,330	1,500	13,400	112,260	24,000	11,720	305.4	2,046	1,776	15,706
Ivory Coast	1	63,990	23,990	—	—	—	12,330	14,480	27,310	—	—	—	—	—	—	—	—	—	4,330
Jamaica	1	36,000	1,800	—	—	—	3,700	—	23,800	—	—	—	—	—	—	—	—	—	850
Japan	30	4,729,890	1,764,195	123,400	20,000	986,980	829,225	181,690	5,016,160	74,690	5,760	207,467	31,350	38,013	2,978	1,459.4	1,863	9,544	84,370
Jordan	1	90,400	21,500	—	—	4,000	10,900	5,220	17,300	—	—	—	—	—	—	16.0	—	—	4,250
Kazakhstan	3	345,093	121,037	24,997	52,071	38,356	51,586	—	177,890	—	—	—	—	—	—	21.5	1,000	124	8,550
Kenya	1	90,000	1,700	—	—	—	8,260	—	36,000	—	—	—	—	—	—	—	—	—	1,000
Kuwait	3	936,000	327,750	72,000	—	36,000	46,620	115,650	588,780	5,616	—	—	—	—	6,561	741.6	2,800	4,200	—
Kyrgyzstan	1	10,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Liberia	1	15,000	1,000	—	—	—	2,000	—	3,300	—	—	—	—	—	—	—	—	—	200
Libya	5	378,000	3,775	—	—	—	20,250	—	43,330	—	—	—	—	635	—	—	—	—	3,432
Lithuania	1	190,000	89,300	—	28,800	43,200	45,900	—	153,900	—	7,200	—	18,900	—	2,700	25.0	—	320	—
Macedonia	1	50,000	—	—	—	—	10,860	—	22,050	—	—	—	4,390	—	—	—	—	—	—
Malaysia	7	538,582	94,335	24,000	—	42,700	75,070	36,000	216,800	—	—	—	10,800	—	—	147.2	2,245	460	24,700

Worldwide Refineries—Capacities as of Jan. 1, 2012

Country	No. of refineries	Crude	Charge capacity, b/cd: Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd: Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (tonnes per day)	Sulfur (tonnes per day)	Asphalt
Martinique	1	17,329	—	—	—	—	2,862	—	14,269	—	—	—	—	—	—	—	—	—	—
Mexico	6	1,540,000	754,000	191,000	—	380,500	279,300	—	926,050	128,456	—	17,000	—	16,600	15,490	183.0	—	—	58,000
Morocco	2	154,901	24,921	—	—	5,040	24,359	—	35,539	—	—	—	—	2,460	—	—	—	—	5,630
Myanmar	3	57,000	4,000	5,200	—	—	—	—	—	—	—	—	—	500	—	—	120	—	—
Netherlands	6	1,196,571	711,095	41,500	91,404	101,983	148,616	198,071	1,016,234	15,450	—	68,968	8,730	11,600	2,715	358.9	—	1,726	16,500
Netherlands Antilles	1	320,000	195,000	—	80,000	50,000	20,000	—	119,500	9,000	2,000	—	—	12,000	—	54.6	—	300	26,000
New Zealand	1	107,000	38,270	—	—	—	25,840	30,000	104,490	—	—	—	—	—	—	60.0	—	111	5,490
Nicaragua	1	20,000	1,500	—	—	—	3,000	—	14,500	—	—	—	—	—	—	—	—	—	—
Nigeria	4	445,000	124,490	—	—	82,700	70,070	—	109,231	9,870	2,274	291	3,610	3,878	—	—	—	—	14,850
North Korea	2	71,000	—	—	—	—	7,300	—	7,400	—	—	1,000	—	—	1,000	—	—	—	—
Norway	2	319,000	—	24,780	32,000	49,000	34,900	—	126,000	—	11,000	—	3,840	—	—	—	610	20	—
Oman	1	85,000	—	—	—	—	16,000	—	21,000	—	—	—	—	—	—	—	—	—	—
Pakistan	6	186,306	19,815	—	—	—	11,650	—	54,870	—	—	1,400	—	3,800	—	—	—	—	4,200
Papua New Guinea	1	32,500	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Paraguay	1	7,500	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Peru	6	198,950	94,000	—	25,700	33,500	2,100	—	2,800	—	—	—	—	—	—	—	—	—	3,800
Philippines	3	273,000	61,000	—	33,000	19,000	51,000	—	184,990	—	—	—	10,000	3,700	—	37.0	—	70	1,200
Poland	4	492,950	265,123	—	—	32,985	67,514	145,908	259,507	3,372	—	10,262	23,194	17,796	2,514	167.0	—	560	33,371
Portugal	2	304,172	87,785	—	36,540	40,500	50,182	9,180	201,537	5,400	—	17,276	—	—	—	85.3	—	252	—
Puerto Rico	1	73,000	34,000	—	—	—	21,000	20,000	21,000	—	—	—	—	—	—	20.0	—	34	—
Qatar	2	338,700	—	—	—	60,000	29,400	20,000	39,350	—	—	—	25,000	—	—	—	—	—	—
Romania	10	537,277	273,225	68,240	37,577	109,478	61,763	1,534	237,625	2,300	—	7,801	3,846	10,366	1,330	18.0	2,555	143	13,761
Russia	40	5,430,908	2,028,570	84,999	382,593	330,817	745,735	57,056	2,170,966	10,006	1,729	54,337	21,869	82,842	7,175	93.3	3,720	726	210,545
Saudi Arabia	7	2,112,000	445,950	—	138,200	103,600	193,160	133,820	493,460	31,500	—	6,500	33,000	—	3,700	190.7	—	—	—
Senegal	1	25,030	7,160	—	—	—	1,590	—	1,930	—	—	—	—	—	—	—	—	—	—
Serbia & Montenegro	2	214,826	50,583	—	20,340	18,950	18,822	—	50,910	3,070	—	200	—	300	—	0.5	—	59	2,400
Sierra Leone	1	10,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Singapore	3	1,357,000	346,000	—	203,710	80,000	146,470	129,360	706,500	9,000	—	48,000	—	45,500	1,400	275.0	—	845	39,500
Slovakia	1	115,000	55,000	—	—	18,000	21,000	42,000	87,800	4,500	—	9,250	6,000	2,000	1,500	89.6	—	270	2,600
Slovenia	1	13,500	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
South Africa	4	484,547	201,375	26,800	60,000	108,640	77,142	11,774	227,772	9,595	4,940	6,900	12,223	8,000	—	50.2	240	607	7,100
South Korea	6	2,759,500	515,650	19,000	—	314,000	342,000	326,500	1,450,380	48,700	—	140,300	—	66,640	10,500	1,385.5	1,200	4,730	81,327
Spain	9	1,271,500	414,245	61,100	149,200	191,300	196,750	131,500	825,380	16,916	—	25,800	36,000	9,600	9,600	300.1	3,565	1,762	26,600
Sri Lanka	1	50,000	24,000	—	12,500	—	5,300	—	19,295	—	—	—	—	—	—	—	—	—	1,000
Sudan	3	121,700	—	—	—	—	1,900	—	8,100	—	—	—	—	—	—	—	—	—	—
Suriname	1	7,000	7,000	—	2,800	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sweden	5	437,000	135,600	—	66,800	29,700	70,660	48,600	268,540	—	3,420	—	28,530	—	—	53.8	—	334	27,460
Switzerland	1	72,000	—	—	—	20,400	12,000	—	33,200	—	3,800	—	6,400	—	—	28.0	—	—	—
Syria	2	239,865	63,135	18,200	22,689	—	31,242	26,410	80,886	—	—	—	11,493	—	—	27.0	500	150	2,223
Tanzania	1	14,900	—	—	2,500	—	2,500	—	4,400	—	—	—	—	—	—	—	—	—	—
Thailand	4	584,250	202,500	—	16,983	91,990	97,770	43,073	428,630	—	—	9,500	19,596	—	—	33.5	—	420	2,500
Trinidad & Tobago	1	168,000	119,200	—	24,000	24,000	18,000	45,000	41,000	1,200	1,580	—	—	—	1,000	30.0	—	100	—
Tunisia	1	34,000	—	—	—	—	3,300	—	—	—	—	—	—	—	—	—	—	—	—
Turkey	6	714,275	201,767	—	23,590	28,935	65,662	53,820	265,005	—	—	—	14,055	5,870	—	217.5	180	315	20,216
Turkmenistan	2	236,970	91,645	28,568	—	15,151	52,540	—	63,500	1,028	1,223	—	—	2,000	—	—	1,040	—	415
Ukraine	6	879,759	336,297	22,149	17,291	70,100	144,711	7,200	315,013	—	—	3,464	—	500	125	21.5	705	176	12,785
United Arab Emirates	5	773,250	92,870	—	—	34,350	25,875	31,050	158,627	1,140	1,900	—	—	—	—	58.8	—	57	700
United Kingdom	10	1,767,168	866,314	64,600	106,958	444,723	339,771	36,000	1,271,541	92,202	13,596	14,590	120,423	23,899	3,967	127.0	2,400	792	28,430
United States	125	17,787,714	7,909,865	2,543,298	34,020	5,649,659	3,492,288	1,726,030	14,061,515	1,142,127	74,810	464,639	678,777	193,100	32,250	4,044.9	131,073	32,284	490,817
Uruguay	1	50,000	25,000	—	7,000	12,000	12,000	—	23,000	—	—	—	6,000	—	—	—	—	—	—
Uzbekistan	3	224,271	45,671	17,667	9,585	—	23,487	—	30,804	—	—	—	—	9,397	—	—	650	—	4,151
Venezuela	5	1,282,100	585,780	144,900	—	231,800	49,500	—	389,700	65,800	—	2,000	20,700	12,020	12,830	147.8	5,200	1,471	36,000
Vietnam	1	140,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Virgin Islands	1	500,000	205,000	55,000	37,000	140,000	105,000	—	435,000	18,000	7,000	18,000	17,000	—	—	—	3,500	500	—
Yemen	2	140,000	10,500	—	—	—	14,500	—	—	—	—	—	—	—	—	—	—	—	3,000
Zambia	1	23,750	2,280	—	—	—	5,320	—	8,550	—	—	—	—	—	—	—	—	—	5,527
Total	655	88,055,552	29,062,130	4,681,023	3,801,129	14,693,328	11,468,147	5,488,694	45,730,072	2,090,102	195,320	1,371,975	1;665,901	802,516	193,074	14,160	209,123	83,256	1,794,824

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APPENDICES TO CONSENT DECREE

APPENDIX 2.4

CALCULATION OF OLEFINS FGRS ESTIMATED PERCENT RECOVERY

APPENDIX 2.4

CALCULATION OF OLEFINS FGRS ESTIMATED PERCENT RECOVERY

1. Calculation of $F_{unrecovered}$ for each hour: Using each hourly average Adjusted Vent Gas Flow Rate ("AVGFR") from the $HF_{vg\text{-}adjusted}$ data set submitted pursuant to paragraph 46.b., calculate hourly unrecovered gas flow ("$F_{unrecovered}$" in KSCFH) due to the AVGFR exceeding operating compressor capacity using the following assumptions:

    a. At least one compressor is assumed to be running at all times.
    b. When the hourly average AVGFR exceeds the capacity of the currently operating compressor(s) ("Cap_{op}" in KSCFH), an additional compressor(s) up to the AVGFR begin(s) operating the next hour. This accounts for the one-hour lag in compressor start up time allowed after the need for the compressor arises for those compressors required to be Available for Operation.
    c. As soon as the hourly reported flow rate does not necessitate one or more of the compressors, that compressor(s) shuts off.
    d. Each compressor and the overall FGRS recovers flow up to its design capacity during periods when the flow exceeds such capacity. Flow above currently operating compressor capacity for each hour is considered unrecovered flow ($F_{unrecovered}$) for that hour and, when AVGFR is greater than Cap_{op} for an hour, is calculated as follows for that hour:

$$F_{unrecovered} = AVGFR - Cap_{op}$$

2. Calculation of $V_{downtime}$: The total volume of gas not recovered due to compressor downtime allowed per the CD ($V_{downtime}$, in KSCF), is calculated using the following assumptions:

    a. Assume that the percentage of downtime for a specific compressor that will result in unrecovered flow is the same as the percentage of overall allowed downtime for that compressor (e.g., if a compressor is allowed to be down 2% of all time, and the compressor is only ever needed for 100 hours over two years, then unrecovered flow due to downtime will occur during 2% of 100 hours, or 2 hours). In other words, assume compressor down time is even distributed over time and does not all occur at times the compressor is needed.
    b. For the compressor in each scenario that is allowed downtime per the CD, calculate the average gas volume over the one year period, not the maximum gas volume, that would be recovered by that specific compressor when needed (i.e., when flow exceeds capacity of upstream compressors and the specific compressor is recovering flow).
    c. Multiply the average gas volume recovered ("$V_{avg\text{-}rec}$") by the compressor when needed by the total number of hours of allowed downtime ("H_d") that occur when the compressor is needed and sum for each hour of downtime:

$$V_{downtime} = \sum_{h=1}^{H_d} H_d \times V_{avg\text{-}rec}$$

APPENDIX 2.4

3. Calculate overall percent recovery over the one year time period (i.e., 8760 hours), according to the equation (where “h” in the summation represents each incremental hour).

$$\text{Estimated Percent Recovery} = \left(1 - \frac{V_{downtime} + \sum_{h=1}^{8760} F_{unrecovered}}{\sum_{h=1}^{8760} AVGFR}\right) \times 100\%$$

A spreadsheet containing hypothetical examples/applications of the above methodology is set forth at the following: http://www2.epa.gov/enforcement/shell-deer-park-spreedsheet

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APPENDICES TO CONSENT DECREE

APPENDIX 2.5

METHODOLOGY FOR CALCULATING THE 365-DAY ROLLING SUM EMISSIONS OF VOLATILE ORGANIC COMPOUNDS FROM THE HIPA FLARE

APPENDIX 2.5

Equations for Calculating the 365-day Rolling Sum Emissions of Volatile Organic Compounds from the HIPA Flare

For the purpose of demonstrating compliance with the Volatile Organic Compound ("VOC") emissions limit for the HIPA flare in Paragraph 49 of this Consent Decree, the block sum of HIPA Flare VOC emissions shall be calculated each day in accordance with the steps prescribed below, and the 365-day rolling sum, rolled daily shall be calculated using data from the prior 365 calendar days. All abbreviations, constants, and variables are defined in the "Key to the Abbreviations" on page 3 of this Appendix. An example calculation spreadsheet can be found at the following: www.epa.gov/enforcement/air/documents/sdp-appendix2-5.xlsx

Step 1: Determine the Molecular Weight ("MW_i") of each Volatile Organic Compound ("VOC") in the Vent Gas.

Take the MW_i values for *i*= 8 through *i*=18 of each individual Vent Gas VOC from column *i* of Table 1 in Appendix 1.3.

Step 2: Determine Compliance with the Net Heating Value of the Combustion Zone ("NHV_{cz}") standard for each calendar day.

Determine for the 365-day rolling sum period the calendar days "*r*" during which the 3-hour rolling average NHV_{cz} standard in paragraph 56.b was met, and the calendar days "*s*" during which the standard was not met.

Step 3: Calculate the block sum mass of VOC emitted for each calendar day "*r*" (i.e., days during which the flare was operated in compliance with the Net Heating Value of the Combustion Zone standard ("$(\dot{M}_{VOC-Emit})_r$").

Step 3a: The mass of VOC in the Vent Gas ("$\dot{m}_{VOC-vg}$") for each calendar day "*r*" shall be calculated as follows using daily block average values of Q_{vg} and x_i for that day:

$$\dot{m}_{VOC-vg} = \sum_{i=8}^{18} \frac{Q_{vg} * MW_i * x_i}{385.5} \qquad \textbf{\textit{Equation 1}}$$

Step 3b: The mass of VOC emitted for a calendar day "r" shall be calculated as follows using a 98% VOC Combustion Efficiency ("CE_{VOC}") and the value for $\dot{m}_{VOC-vg}$ from Equation 1:

$$(\dot{M}_{VOC-Emit})_r = \dot{m}_{VOC-vg} * (1 - CE_{VOC} / 100) * 24 \qquad \textbf{\textit{Equation 2}}$$

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Step 4: Calculate the block sum mass of VOC emitted for each calendar day "*s*" during which the Net Heating Value of the Combustion Zone standard was not met ("$(\dot{M}_{VOC-Emit})_s$")

Step 4a: The mass of VOC in the Vent Gas shall be calculated for each 1-hour block sum period "*j*" of the calendar day "*s*" as follows using each hourly block average value for Q_{vg} and x_i that day:

$$(\dot{m}_{VOC-vg})_j = \sum_{i=8}^{18} \frac{Q_{vg} * MW_i * x_i}{385.5} \qquad \textit{\textbf{Equation 3}}$$

Step 4b: Calculate NHV_{cz} for each 1-hour block sum period "*j*" of the calendar day "*s*" ("$(NHV_{cz})_j$") using the equations in Step 6 of Appendix 1.3.

Step 4c: Calculate the Combustion Efficiency of VOC for each 1-hour block sum period "*j*" ("$(CE_{VOC})_j$") of calendar day "*s*":

If $(NHV_{cz})_j < 95$ BTU/scf:

$$(CE_{VOC})_j = 0 \qquad \textit{\textbf{Equation 4a}}$$

If $\left(NHV_{cz}\right)_j \geq 95\, BTU/scf$:

$$(CE_{VOC})_j = \frac{0.16 * \left(-95 + (NHV_{cz})_j\right)}{1 + 0.16 * \left(-95 + (NHV_{cz})_j\right)} * 100 \qquad \textit{\textbf{Equation 4b}}$$

Step 4d: The block sum mass of VOC emissions from the HIPA Flare during calendar day "*s*" shall be calculated as shown below in Equation 5 as the sum of the hourly block sum VOC emissions calculated for each hour "*j*" during that calendar day.

$$(\dot{M}_{VOC-Emit})_s = \sum_{j=1}^{24} \left[(\dot{m}_{VOC-vg})_j * \left(1 - (CE_{VOC})_j / 100\right) \right] \qquad \textit{\textbf{Equation 5}}$$

Step 5: Calculate the tons per year of VOC emissions ("$TPY_{VOC-Emit}$").

The results of Equation 2 for each day "r" and Equation 5 for each day "s" of the 365-day rolling sum period are summed and converted to tons per year as per Equation 6 below. The result of Equation 6 is used to demonstrate compliance with the HIPA Flare VOC limit in the consent decree.

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$$TPY_{VOC-Emit} = \frac{\sum_r (\dot{M}_{VOC-Emit})_r + \sum_s (\dot{M}_{VOC-Emit})_s}{2000} \qquad \textbf{\textit{Equation 6}}$$

Key to the Abbreviations:

0.16 = CE_{VOC} *multiplier for* NHV_{cz} *(unitless)*
24 = *Number of hours in a calendar day (24 hr/d)*
95 = NHV_{cz} *below which* CE_{VOC} *empirically correlates to zero (BTU/scf)*
385.5 = *conversion from pound moles to standard cubic feet (385.5 lb/scf)*
2000 = *conversion from pounds to tons (2000 lb/ton)*
CE_{VOC} = *percent combustion efficiency of VOC in the Vent Gas (%)*
i = individual numbered compound from column i in Table 1 of Appendix 1.3 (unitless)
j = individually numbered hours in a calendar day with NHV_{cz} *non-compliance (unitless)*
$(\dot{M}_{VOC-Emit})_r$ = *mass of VOC emitted for calendar day in* NHV_{cz} *compliance (lb/d)*
$(\dot{M}_{VOC-Emit})_s$ = *mass of VOC emitted for calendar day with* NHV_{cz} *non-compliance (lb/d)*
$\dot{m}_{VOC-vg}$ = *calendar day average mass flow rate of VOC in the Vent Gas (lb/hr)*
$(\dot{m}_{VOC-vg})_j$ = *average mass flow rate of VOC in the Vent Gas during hour "j" (lb/hr)*
MW_i = *molecular weight of individual compound (lb/lb-mole)*
NHV_{cz} = *net heating value of the combustion zone (BTU/scf)*
Q_{vg} = *vent gas volumetric flow rate (scfh)*
r = calendar day when no exceedences of the NHV_{cz} *standard occurred (unitless)*
s = calendar day during which exceedence(s) of the NHV_{cz} *standard occurred (unitless)*
$TPY_{VOC-Emit}$ = mass flow rate of VOC emissions (tons/yr)
VOC = *volatile organic compound in the vent gas (unitless)*
x_i = *individual compound volume fraction in the vent gas (volume fraction)*

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APPENDIX 2.6

MITIGATION PROJECT AT THE NORTH EFFLUENT TREATER

APPENDIX 2.6

MITIGATION PROJECT: NORTH EFFLUENT TREATER CONTROLS

2.6.1. By the dates set forth herein, SDP shall implement the Environmental Mitigation Project described in this Appendix 2.6 for the purpose of reducing emissions of hazardous air pollutants ("HAPs") and volatile organic compounds ("VOCs") from the North Effluent Treater at the Covered Facilities.

2.6.2. Definitions

a. "Breakthrough" shall mean, for purposes of monitoring a carbon canister, any reading equal to or greater than 50 ppm VOC or 1 ppm benzene (depending upon the parameter that SDP decides to monitor).

b. "DAF" shall mean the Dissolved Air Flotation unit that is located at the North Effluent Treater and marked as such on the schematic attached as Exhibit 1.

c. "Manhole 4 Sump" shall mean the manhole at the North Effluent Treater that is marked as "Manhole 4 Sump" on Exhibit 1.

d. "North Effluent Treater" or "NET" shall mean the wastewater treatment plant located centrally at the north end of the SDP Refinery and Chemical Plant Facilities. It treats wastewater from the Covered Facilities using primary, secondary, and tertiary treatment. Treated water is discharged into the Houston Ship Channel. A plot plan showing the location of the North Effluent Treater is attached as Exhibit 2.

e. "Trickling Filter Sump" shall mean the sump that is located downstream of the Trickling Filter at the NET and marked as "Trickling Filter Sump" on Exhibit 1.

f. "Trickling Filter" shall mean the fixed-growth biological treatment unit that uses a slime-covered stone filter packing to treat effluent from the DAF prior to further biological treatment in the aeration basins at the NET. The Trickling Filter is marked as such on Exhibit 1.

2.6.3. Objective. The objective of this Appendix is to reduce VOC emissions from the Manhole 4 Sump, the DAFs, the Trickling Filter, and the Trickling Filter Sump. SDP requires further time to study some of the options available to achieve this objective, but this objective would be thwarted—and it would be a violation of the terms of this Appendix—if SDP merely redirected the waste stream(s) from one or more of these four units to uncovered and/or uncontrolled waste management unit(s).

2.6.4. Trickling Filter. By no later than December 31, 2019, SDP shall permanently take the Trickling Filter out of service by physically removing all connections that would allow the Trickling Filter to be used. SDP shall complete taking the Trickling Filter out of service by surrendering any permits to operate the Trickling Filter.

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2.6.5. Manhole 4 Sump and Trickling Filter Sump. By no later than December 31, 2015, SDP shall undertake all necessary modifications to the Manhole 4 Sump and the Trickling Filter Sump such that each of them conforms to the requirements of 40 C.F.R. § 61.346(a). SDP also shall install on each of these Sumps a closed vent system and control device that conforms to the requirements of Paragraphs 2.6.6. and 2.6.7., respectively.

2.6.6. DAF. By no later than December 31, 2019, SDP shall undertake one of the following actions at the DAF:

a. Undertake all necessary modifications to the DAF such that the DAF conforms to the requirements of 40 C.F.R. § 61.347. Under this option, SDP shall install on the DAF a closed vent system and control device that conform to the requirements of Paragraphs 2.6.7. and 2.6.8., respectively.

b. Replace the DAF with a new dissolved air flotation unit that conforms to the requirements of 40 C.F.R. § 61.347. Under this option, SDP shall install on the new dissolved air flotation unit a closed vent system and control device that conform to the requirements of Paragraphs 2.6.7. and 2.6.8., respectively.

c. Remove the DAF permanently from service. If SDP elects to use this option, SDP shall either:

i. Send the waste stream off-site, by means of a hard-piped conveyance system, to a federally-permitted wastewater treatment plant; or

ii. Ensure that the waste stream that no longer is directed to the DAF is transferred to waste management unit that is covered and controlled in conformance with 40 C.F.R. Part 61, Subpart FF.

2.6.7. Closed Vent System Requirements. For the Manhole 4 Sump, the Trickling Filter Sump, and the DAF (to the extent it is either retrofitted with controls (¶ 2.6.6.a) or replaced with a new DAF that is controlled (¶2.6.6.b)), SDP shall design, install, operate, and maintain a closed vent system in conformance with 40 C.F.R. § 61.349(a)(1). The closed vent system shall conform to all requirements of 40 C.F.R. § 61.349 related to closed vent systems.

2.6.8. Control Device Requirements.

a. General. SDP shall route all vapors from the closed vent systems required pursuant to Paragraph 2.6.7. to one or more control devices, each of which is designed, installed, operated, and maintained in conformance with 40 C.F.R. § 61.349(a)(2)(i) or (ii) or (iii). The control device(s) shall conform to all requirements of 40 C.F.R. § 61.349 related to control devices.

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b. Carbon Adsorption System. To the extent that SDP installs a carbon adsorption system as one or more control devices, SDP shall comply with the following requirements:

i. Dual Canisters. SDP shall install primary and secondary carbon absorption canisters and operate them in series (the "dual canister" configuration). SDP may comply with the dual canister configuration by using a single canister with a "dual carbon bed" if the dual carbon bed configuration nonetheless allows SDP to be able to monitor for breakthrough between the primary and secondary beds consistent with Subparagraph 2.6.8.b.ii.

ii. Monitoring. After installation, SDP shall monitor for breakthrough between the primary and secondary canisters/beds at times when there is actual flow to the canisters/beds. Monitoring between the primary and secondary canisters/beds shall occur on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. SDP shall monitor the outlet of the secondary canister/bed on a monthly basis or at its design replacement interval (whichever is less) to verify the proper functioning of the system.

iii. Replacement. SDP shall replace the original primary carbon canister/bed (or route the flow to an appropriate alternative control device) immediately when breakthrough is detected. The original secondary carbon canister/bed (or a fresh carbon canister/bed) shall become the new primary canister/bed and fresh carbon canister/bed will become the secondary carbon canister/bed. For purposes of this Subparagraph, "immediately" shall mean eight (8) hours for canisters/beds of 55 gallons or less; twenty four (24) hours for canisters/beds between 55 gallons up to 20,000 pounds; and forty-eight (48) hours for canisters/beds 20,000 pounds or larger.

iv. Maintaining Canister Supplies. SDP will maintain a supply of fresh canisters/beds at the Covered Facilities at all times.

v. Work Practice. For carbon canisters/beds that are 20,000 pounds or greater, as soon as breakthrough is detected, SDP shall ensure that all emissions are vented to the secondary canister/bed and shall monitor the outlet to the secondary canister/bed on an hourly basis until the replacement canister is in place.

vi. Notify EPA about Monitored Parameter. In the first report due under Paragraph 86 after installation of the carbon adsorption system, SDP shall notify EPA about whether it is monitoring for breakthrough using 50 ppm VOC or 1 ppm benzene.

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c. Any Control Device Other than a Carbon Adsorption System. To the extent that SDP installs or uses any control device other than or in addition to a carbon adsorption system to comply with Subparagraph 2.6.8.a (*e.g.* SDP may install a carbon adsorption system to control some part of the closed vent emissions and install or use a different system to control other parts), such device must conform to the requirements of 40 C.F.R. § 61.349(a)(2)(i) or (ii) or (iii). In the first report due under Paragraph 85 after SDP has selected a control device other than a Carbon Absorption System, SDP shall include a detailed description of the control device(s) it has selected, including how and where the device shall be incorporated into the closed vent system, and a schematic identifying the location(s).

Exhibit 1 to Appendix 2.6

SHELL DEER PARK SITE
NORTH EFFLUENT TREATER
FLOW SCHEMATIC

7 MARCH 2013

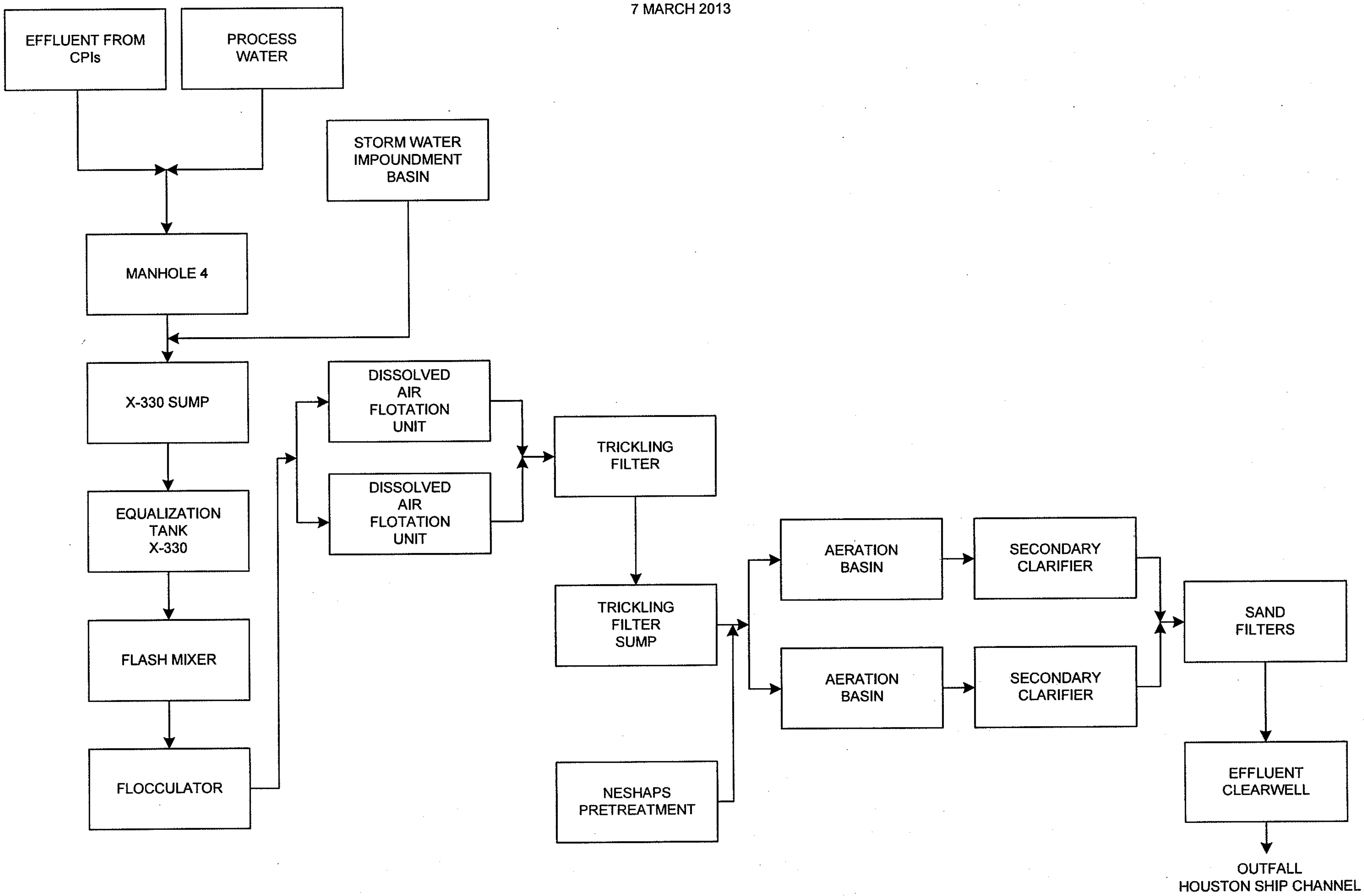
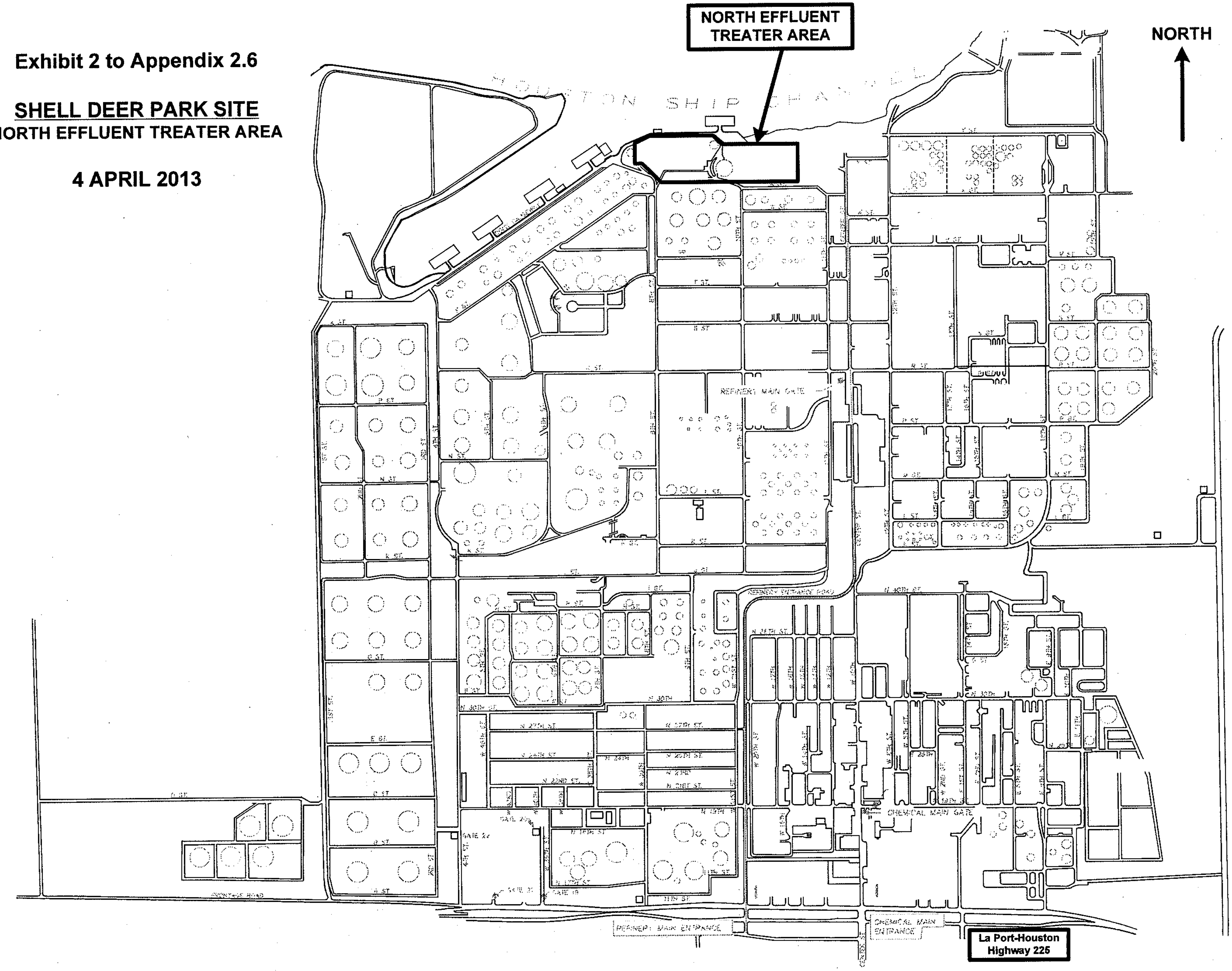


Exhibit 2 to Appendix 2.6

SHELL DEER PARK SITE
NORTH EFFLUENT TREATER AREA

4 APRIL 2013



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APPENDICES TO CONSENT DECREE

APPENDIX 2.7

MITIGATION PROJECT AT CERTAIN TANKS

APPENDIX 2.7

MITIGATION PROJECT: TANK CONTROLS

Tank Retirements, Retrofits, and Inspection

1. By no later than July 1, 2015, SDP shall take Tanks TOL-912 and TOL-913 permanently out of service. Tanks TOL-912 and TOL-913 shall be replaced by existing Tanks TOL-901 and TOL-911. Prior to July 1, 2015, Tanks TOL-901 and TOL-911 each shall be retrofitted with aluminum geodesic domes to mitigate the effect of wind on emissions.

2. By no later than December 31, 2013, Shell shall take Tank TOL-920 temporarily out of service for inspection. When out of service, SDP shall undertake a full internal inspection and make any repairs necessary to assure that the tank is in good working order and complies with all applicable regulatory control requirements.

Infrared Gas-Imaging Program for Tanks Associated with the ACU/BEU

3. "ACU" shall mean the Aromatics Concentration Unit. "BEU" shall mean the Benzene Extraction Unit. For the purpose of this Mitigation Project, "Tanks Associated with the ACU/BEU" or "Tanks" shall mean all tanks that receive or supply benzene or benzene-containing material from/to the ACU or BEU and are located within the tank farm denoted by "Aromatics Tank Farm" on the plot plan attached as Exhibit 1 to Appendix 2.7. As of the Date of Lodging of this Consent Decree, the "Tanks Associated with the ACU/BEU" are as follows:

Tank	Service
D370	Benzene Service
D380	Benzene Service
D381	Benzene Service
D371	Benzene Service
L306	Benzene Service
D351	Benzene/Toluene Service
D352	Benzene/Toluene Service
J313	Benzene-Containing Service
D353	Benzene-Containing Service
D377	Reformate
D379	Reformate
J312	Heavy Naphtha
J314	Benzene-Containing Service
D350	Benzene/Toluene Service
L305	Benzene/Toluene Service

4. During the life of this Consent Decree, the Tanks Associated with the ACU/BEU may change (*e.g.*, tanks may be retired, taken out of ACU/BEU service, or added to ACU/BEU service). Within 30 days of any such change, SDP shall send a notice to EPA

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updating the list of Tanks Associated with the ACU/BEU. Such a change is not a material modification of this Consent Decree.

5. Except as provided in the last sentence of this Paragraph, by no later than one month after the Date of Entry of this Consent Decree, SDP shall commence a once-every-two-calendar-weeks (*i.e.*, bi-weekly) Infrared Gas-Imaging Program of the Tanks Associated with the ACU/BEU that are in-service (*i.e.*, when hydrocarbons are in a tank) using infrared gas-imaging cameras such as FLIR cameras or their equivalent. The cameras used in this Program shall be capable of imaging organic gases that absorb infrared light in approximately the 3.2 to 3.4 micron range, and have an automatic mode (for thermal contrast and brightness) of gas imaging. For any specific tank, SDP shall not be required to undertake the infrared gas-imaging required by this Paragraph during any time period in which, pursuant to Subparagraph 9.b and the notice required in Subparagraph 9.e, the tank is being repaired, is being removed from service, or is removed from service.

6. The Infrared Gas-Imaging Program will be conducted by trained personnel who maintain proficiency through regular use of the infrared gas-imaging camera. Prior to implementation of the Program, personnel shall receive training in infrared gas-imaging camera fundamentals and operation.

7. For the purpose of this Mitigation Project, the concept of "observing emissions" or "emissions being observed" means any visual indication of organic gases on the screen of an infrared gas-imaging camera.

8. <u>Tank Imaging.</u>

    a. All imaging shall be done with the camera in automatic mode and shall be of all vents of each tank. Imaging shall be done from the ground and conducted as close as possible to the vent but at a distance of no more than 50 feet from a vent.

    b. During each bi-weekly monitoring period, an initial imaging of each tank shall take place regardless of whether the tank is filling, drawing down, or static.

        i. If the imaging operator does not observe emissions during the initial imaging, no further imaging of the tank is required in the monitoring period.

        ii. If the imaging operator observes emissions during the initial imaging, SDP will idle the tank so its contents are static and then reimage the tank. If no emissions are observed during the static imaging, no further actions are required in the monitoring period.

        iii. If emissions are observed during the static imaging, then SDP will proceed with the requirements under Paragraph 9 of this Mitigation Project.

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9. Tank Inspection, Repair, and Notification. If emissions are observed during the static tank imaging, SDP shall:

   a. Conduct a visual inspection through manholes and roof hatches of the internal floating roof, the primary seal, and secondary seal(s) (if one (or more) is in service) within 48 hours of the static tank imaging that resulted in emissions being observed.

   b. If, during the inspection required by Subparagraph 9.a., the internal floating roof is not resting on the surface of the liquid inside the tank and is not resting on the leg supports; or there is liquid on the floating roof; or the seal(s) is(are) detached; or there are holes or tears in the seal fabric; or there are visible gaps between the seal(s) and the wall of the tank, SDP shall repair all the items, or, if one or more repairs cannot be made, shall empty and remove the tank from service within 45 calendar days. If the failures cannot be repaired or the tank cannot be emptied within 45 calendar days, SDP may utilize no more than 2 extensions of no more than 30 calendar days each. SDP may utilize an extension of time only if alternate storage capacity is unavailable.

   c. If, during the visual inspection required pursuant to Subparagraph 9.a, none of the failures described in Subparagraph 9.b are observed, then no further action is required unless and until the requirements of Subparagraph 9.d are met.

   d. Tank Replacement/Dispute Resolution Invocation Requirements.

      i. Applicability. The requirements of this Subparagraph apply only when:

         (1) SDP has undertaken four static imaging events within a 26-week period after the tank returns to service following a repair made pursuant to Subparagraph 9.b;

         (2) During each of those four events, emissions are observed (Subparagraph 8.b.iii applies); and

         (3) During each of the follow-up visual inspections to those four events, no repairs are made pursuant to the timeframes in Subparagraph 9.b.

      ii. Tank Replacement/Dispute Resolution Invocation. If the applicability requirements in Subparagraph 9.d.i are met, SDP must either:

         (1) Replace the tank, in which case, SDP shall replace the tank by no later than two years after the inspection triggering the replacement requirement occurs; or

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(2) Invoke dispute resolution. Prior to invoking the dispute resolution provisions of Section XII.A, SDP informally shall consult with EPA for a period not to exceed 60 days. Thereafter, if the dispute remains, SDP shall invoke the dispute resolution provisions of Section XII.A. In any such dispute, SDP shall bear the burden of demonstrating by substantial evidence that new, changed, or previously unknown circumstances or information render it very likely that if the tank were returned to service without being replaced, emissions would not be observed from the tank for at least 13 bi-weekly imaging events. For the duration of this Consent Decree, SDP shall be entitled to invoke dispute resolution on any tank only one time.

iii. Interim Period. Within 105 days after the inspection that triggers this Subparagraph occurs: *(1)* SDP shall use best efforts to identify alternate tank capacity that can be used continuously until the replacement tank is available; or *(2)* if alternate tank capacity cannot be identified, SDP shall submit a plan to EPA to minimize, to the extent practicable, the use of the tank until the replacement tank is available. If *(1)* applies, SDP shall use the alternate capacity until the replacement tank is available. If *(2)* applies, SDP shall implement the plan.

e. SDP shall notify EPA in writing of the discovery of a tank failure(s) (as described in paragraph 9.c.) within 30 days. Such notice shall describe in detail the tank failure and SDP's detailed plans regarding repair of the tank and/or emptying of the tank.

f. Within 10 days of the end of the original 45 day repair period and within 7 days of the end of the first 30 day extension, SDP shall notify EPA in writing of a decision to utilize an extension of time. Documentation of a decision to utilize an extension shall include the reasons for the extension, an explanation about the unavailability of alternate storage capacity, and a schedule of actions that will ensure that the tank will be repaired or the tank will be emptied as soon as practical.

g. After completion of the repairs done pursuant to subparagraph 9.b., SDP shall re-image the tank as verification that the tank is in good working order and complies with all applicable regulatory control requirements.

10. In each Semi-Annual Report required pursuant to Section IX of this Consent Decree, SDP shall include a narrative description of the infrared gas-imaging done pursuant to this Mitigation Project, including but not limited to:

a. A certification that all Tanks Associated with the ACU/BEU that were in-service (i.e., that had hydrocarbons in the tank) at the time of the monitoring were monitored in compliance with the terms of this Mitigation Project; an identification of each Tank Associated with the ACU/BEU that was not monitored, including an identification of how many bi-weekly monitoring event(s) were not undertaken for the tank; and a certification that the Tanks Associated with the ACU/BEU that were not monitored during any monitoring event were not in-service (i.e., did not have hydrocarbons in the tank) .

b. A record of the camera operator, date, time, weather conditions, tanks imaged, and a written summary of the results (including identification of individual vent and/or emission point locations). A notation should be made if a planned imaging was not completed due to inclement weather, worker safety, or Force Majeure.

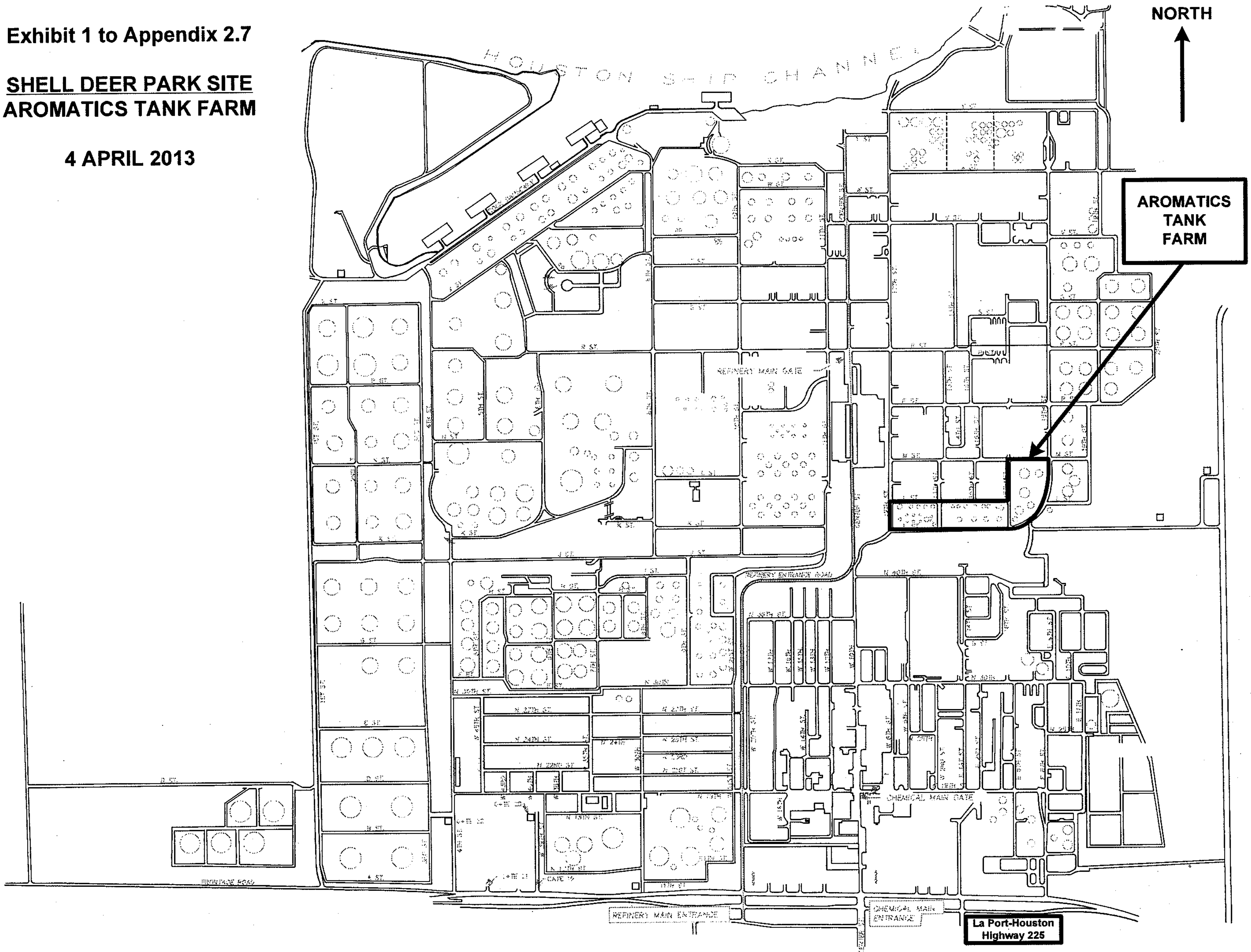
c. The infrared recordings (10 to 30 seconds) of any emissions observed during an infrared gas imaging conducted pursuant to this Mitigation Project.

d. A record of what was done in response to the observation of emissions, including inspection results and repairs.

Exhibit 1 to Appendix 2.7

SHELL DEER PARK SITE
AROMATICS TANK FARM

4 APRIL 2013



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APPENDIX 2.8

MITIGATION PROJECT AT THE ACU AND BEU

APPENDIX 2.8

MITIGATION PROJECT: ACU AND BEU CONTROLS

2.8.1. By the dates set forth herein, SDP shall implement the Environmental Mitigation Project described in this Appendix 2.8 for the purpose of reducing emissions of hazardous air pollutants ("HAPs") and volatile organic compounds ("VOCs") from the Aromatic Concentration Unit ("ACU") and the Benzene Extraction Unit ("BEU").

2.8.2. PRV Review

a. By no later than six months after the Date of Entry of this Consent Decree, SDP shall retain a third-party to undertake a review of the pressure relief valves ("PRVs") in the ACU and BEU. Using the leak detection and repair ("LDAR") database that is the most current one for the SDP Chemical Plant at the time this action is undertaken, as well as any other necessary documents (*e.g.*, piping and instrumentation drawings, HON semi-annual reports), the third-party shall identify each pressure relief valve ("PRV") in the ACU and BEU and shall review the operational parameters of, and applicable regulatory requirements for, each PRV. The third-party shall make at least the following determinations:

(1) Location of the PRV

(2) Size of the PRV

(3) "State" of the process fluid in contact with the PRV (*e.g.*, gas/vapor, light liquid, heavy liquid)

(4) Whether the PRV is in vacuum service

(5) Whether the PRV vents to the atmosphere

(6) Appropriate monitoring frequency for the PRV

(7) Appropriate monitoring method(s) for the PRV (*e.g.*, Method 21, audio/visual/olfactory)

(8) Each regulatory requirement applicable to the PRV

b. After completing its review, the third-party shall meet with SDP to discuss its determinations. The third-party and SDP shall make final decisions regarding each applicable regulatory requirement for each PRV. By no later than twelve months after the Date of Entry, SDP shall update its LDAR database as necessary to accurately reflect the final decisions made.

2.8.3. DTM and UTM Review

a. By no later than six months after the Date of Entry of this Consent Decree, SDP shall retain a third-party to undertake a review of SDP's designations of "difficult-to-monitor" ("DTM") and "unsafe-to-monitor" ("UTM") pieces of equipment in the

APPENDIX 2.8

ACU and BEU. Using the LDAR database that is the most current one for the SDP Chemical Plant at the time this action is undertaken, as well as any other necessary documents (*e.g.*, piping and instrumentation drawings, HON semi-annual reports), the third-party shall identify each component that SDP lists as DTM and UTM in the ACU and BEU and shall review whether each such DTM and UTM designation is appropriate based on the applicable regulations for the component.

b. After completing its review, the third-party shall meet with SDP to discuss its determinations. The third-party and SDP shall make final decisions regarding each DTM and UTM designation. By no later than twelve months after the Date of Entry, SDP shall update its LDAR database as necessary to accurately reflect the final decisions made.

2.8.4. Comparative Monitoring

a. In a time period that is sufficient to enable SDP to meet the reporting requirements in Subparagraph 2.8.4.d and to try to meet the goal in the last sentence of Subparagraph 2.8.4.c, SDP shall retain a third-party to undertake comparative monitoring of the ACU and BEU. In undertaking the required monitoring, the third-party shall:

i. Calculate a Comparative Monitoring Leak Percentage. The third-party shall calculate a leak percentage for the ACU and a leak percentage for the BEU, broken down by component type (*e.g.*, valves, pumps, connectors, *etc.*).

ii. Calculate the Historic, Average Leak Percentage from Prior Periodic Monitoring Events. The third-party shall calculate the historic, average leak percentage from prior periodic monitoring events in the ACU and BEU, broken down by component type (*e.g.*, valves, pumps, connectors, *etc.*) but excluding pieces of equipment that were DTM and UTM during the monitoring periods used. The following number of complete monitoring periods immediately preceding the third-party's comparative monitoring shall be used for this purpose:

Valves (including pressure relief valves)	4 periods
Pumps and Agitators	12 periods
Connectors	2 periods

iii. Calculate the Comparative Monitoring Leak Ratio. For the ACU and the BEU, the third-party shall calculate the ratio of the Comparative Monitoring Leak Percentage (from Paragraph 2.8.5.a) to the Historic, Average Leak Percentage (from Paragraph 2.8.5.b). This ratio shall be called the "Comparative Monitoring Leak Ratio." If, in calculating this ratio, the denominator is "zero," it shall be assumed that one leaking piece of equipment was found

APPENDIX 2.8

through routine monitoring during the period before the comparative monitoring took place.

b. <u>Comparative Monitoring Leak Ratio Report</u>. In a time period that is sufficient to enable SDP to meet the reporting requirements in Subparagraph 2.8.4.d and to try to meet the goal in the last sentence of Subparagraph 2.8.4.c, the third-party shall submit a report to SDP that identifies the Comparative Monitoring Leak Ratios, broken down by component type, in the ACU and in the BEU. For any Comparative Monitoring Leak Ratio that is 3.0 or higher *and* where the Comparative Monitoring Leak Percentage is greater than or equal to 0.5, the third-party shall provide its opinion about possible causes and corrective actions.

c. <u>Preliminary Corrective Action Plan ("Preliminary CAP")</u>. In a time period that is sufficient to enable SDP to meet the reporting requirements in Subparagraph 2.8.4.d and to try to meet the goal in the last sentence of this Subparagraph 2.8.4.c, SDP shall develop a preliminary correction action plan for any Comparative Monitoring Leak Ratio that is 3.0 or higher *and* where the Comparative Monitoring Leak Percentage is greater than or equal to 0.5. The preliminary CAP shall describe the actions that SDP has taken or shall take to identify and address the causes of the high Comparative Monitoring Leak Ratio(s). SDP shall include a schedule by which corrective actions that have not yet been completed shall be completed. SDP shall complete each corrective action as expeditiously as practicable with the goal of completing each action by no later than twelve months after the Date of Entry.

d. <u>Submission of Final CAP to EPA</u>. In the first semi-annual report under Section XI of this Decree that is due no sooner than twelve months after the Date of Entry, SDP shall submit a final CAP to EPA, together with a certification of completion of each item of corrective action. If any item of corrective action is not completed at the time of the submission of this Final CAP, SDP shall explain the reasons, together with a schedule for prompt completion. SDP shall then submit a supplemental certification of completion those items of corrective action in the semi-annual report that is due for the period in which the action(s) was(were) completed.

2.8.5. <u>Qualifications of Third-Party</u>. For any actions in this Appendix 2.8 that must be undertaken by a "third-party," SDP shall retain a company/consultant that has significant experience conducting LDAR compliance evaluations and Method 21 monitoring. The company/consultant must be a company different than the SDP Chemical Plant's regular LDAR contractor.

2.8.6. <u>Dual Mechanical Seals on Pumps</u>. By no later than two years after the Date of Entry of this Consent Decree, SDP shall upgrade the following two pumps in the BEU with a dual mechanical seal system that meets all of the requirements of 40 C.F.R. § 63.163(e)(1)-(3): (1) G/0 PMP DP-2206 (E Sde of Ves V-900) (LDAR tag P0071); and (2) G/0 PMP DP-2207 (E Sde of Ves V-900) (LDAR tag P0070).

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2.8.7. FLIR Camera Protocol.

a. By no later than one month after the Date of Entry of this Consent Decree, SDP shall commence an Infrared Gas-Imaging Program of the ACU and BEU using infrared gas-imaging cameras such as FLIR cameras or their equivalent. The cameras used in this Program shall be capable of imaging organic gases that absorb infrared light in approximately the 3.2 to 3.4 micron range, and have at least a high-sensitivity mode (enhanced detection) and automatic mode (for thermal contrast and brightness) of gas imaging.

b. The Infrared Gas-Imaging Program shall be conducted by trained personnel who maintain proficiency through regular use of the infrared gas-imaging camera. Prior to implementation of the Program, personnel shall receive training in infrared gas-imaging camera use and operation.

c. All ground level imaging shall be conducted at a distance of no more than 50 feet from the imaging target.

d. For the purpose of this Appendix, the concept of "observing excess emissions" or "excess emissions being observed" means any visual indication of organic gases on the screen of an infrared camera.

e. Observed excess emissions will monitored using Method 21. Components that exceed regulatory requirements will be repaired consistent with existing regulations.

f. Infrared Gas-Imaging monitoring frequency for equipment that contains VOCs greater than 5% shall be as follows:

i. Pumps – every two weeks
ii. Atmospheric PRV's – every two weeks
iii. Valves – once per month
iv. Connectors – once per quarter

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APPENDIX 2.9

FENCE LINE MONITORING SUPPLEMENTAL ENVIRONMENTAL PROJECT

APPENDIX 2.9

SCOPE OF WORK FOR THE SUPPLEMENTAL ENVIRONMENTAL PROJECT: FENCE LINE OPEN-PATH MONITORING ("AIR MONITORING SOW")

Objectives

1. This Supplemental Environmental Project ("SEP") entails: (i) using an open-path ambient air monitor to measure and record benzene concentrations in the ambient air at the Covered Facilities' southeast fence line; (ii) using a Meteorological Station to record weather variables simultaneously with pollutant measurements; and (iii) responding with corrective actions to abate emissions.

Definitions

2. The following terms shall be defined as follows for the purposes of this Air Monitoring SOW:

"Air Monitoring System" or "AMS" shall mean a system consisting of one UV DOAS Analyzer, one optical fiber multiplexer, two emitter telescopes, and two receiver telescopes on the Covered Facilities' southeast fence line, and a co-located Meteorological Station. These instruments shall be configured so that the emitter and receiver telescopes create two 300 meter paths in an east-west orientation; the Analyzer shall alternate measurements between the two paths on an hourly basis by means of an optical fiber multiplexer.

"Data Acquisition System" or "DAS" shall mean a computer-based data collection system that collects, organizes, and presents the data collected by the AMS.

"Field Investigation" shall mean the investigatory process by which Shell Deer Park ("SDP") attempts to determine all potential cause(s) of a Screening Condition.

"Infrared Camera" shall mean an organic gas-imaging camera.

"Investigation Team" shall mean one or more SDP employees or contractors that conduct Field Investigations in response to a Screening Condition. SDP shall ensure that members of the Investigation Team, before conducting a Field Investigation, have received appropriate training necessary to enable the team members to carry out their responsibilities on the Investigation Team.

"Meteorological Station" shall mean a station that includes: (i) a 2-axis sonic anemometer for measuring wind speed and direction; and (ii) temperature and barometric pressure sensors for standardizing gas concentration data to volumetric (ppbV) concentrations. The Meteorological Station shall be connected to the DAS. The data averaging for the wind speed, wind direction, temperature, and barometric pressure shall be timed to be contemporaneous with the 5-minute average gas concentration measurements taken by the UV DOAS Analyzer. The Meteorological Station shall be located away from structures so that wind speed and direction measurements are representative of the measurement site.

"Multiplexer" shall mean a device used to connect two optical paths to a single UV DOAS Analyzer and to switch the measurements between one path and the other.

"Portable PIDs" shall mean portable photo-ionization detectors. For purposes of this SOW, Portable PIDs shall have a minimum sensitivity of 10 ppbV for organic gases measured as isobutylene.

"ppbV" shall mean parts per billion by volume normalized to standard temperature and pressure.

"Screening Condition" shall mean SDP Relevant Data that consists of either: (i) three or more 5-minute benzene concentration data points as measured by the AMS within any one-hour period that are each 15 ppbV or greater, provided that the five-minute average wind direction measurements, taken contemporaneously with the three benzene concentrations of 15 ppbV or greater within any one-hour period, are all within a range of no more than 40 degrees azimuth when concentration is plotted against the wind direction; or (ii) any one 5-minute benzene data point as measured by the AMS that is greater than 50 ppbV.

"SDP Relevant Data" shall mean: (a) the 5-minute average benzene data points collected during periods when the wind direction was from 270 to 360 degrees; and (b) all wind speed and direction data.

"Toxic Vapor Analyzer" or "TVA" shall mean a portable flame-ionization detector suitable for use in performing EPA Method 21.

"UV DOAS Analyzer" shall mean an open-path ultraviolet differential optical absorption spectrometer that uses the unique absorption by chemicals of specific wave lengths in the ultraviolet spectrum to identify and quantify individual chemicals in the ambient air. For the purposes of this SOW, the UV DOAS Analyzer shall be capable of achieving a detection limit of 3 ppbV for benzene and shall generate a data point for average benzene concentration every 5-minutes. The 5-minute data point for benzene shall represent an average of discreet data points collected during the 5-minute averaging period.

Minimum Equipment Requirements

3. In order to implement this SEP, SDP shall maintain in good working order at the Covered Facilities at least all of the following systems and equipment for the duration of this SEP:

   a. The AMS;
   b. The DAS; and
   c. Two Infrared Cameras, two Portable PIDs, and two TVAs.

AMS Equipment Configuration and Data Collection Requirements

4. The UV DOAS Analyzer shall be installed such that the optical paths it measures have a generally east-west orientation as per the location identified in Exhibit 1 to this Appendix.

5. The UV DOAS Analyzer shall be connected to a DAS that shall integrate the gas concentration and meteorological data in order to show the gas-concentration-wind-direction correlations during any hour in which a Screening Condition occurs.

6. The Meteorological Station shall be located near the optical paths measured by the AMS. The wind sensors (i) shall be located on a 10 meter mast unless adjustments are required due to obstructions from the overpass located next to the fence line, and (ii) shall, to the extent practicable, be positioned away from, or above, obstructions such as buildings and process units that may interfere with wind direction measurements.

7. All numerical data collected for the duration of this SEP shall be stored and maintained in a format that can be used in common spreadsheet programs.

Field Investigation – Minimum Requirements

8. Upon the occurrence of a Screening Condition, SDP shall begin a Field Investigation as soon as possible but no later than 24 hours after the Screening Condition. At a minimum, the Field Investigation shall include a review of the data from the AMS and relevant operational data from the Facility to locate the potential source(s) from which the emissions originated.

9. Upon identifying the general area(s) from which the emissions originated, SDP shall deploy an Investigation Team to the area(s). The Investigation Team shall survey potential sources of the emissions by conducting a monitoring survey using Portable PIDs and Infrared Cameras. Infrared Cameras shall be used in high sensitivity mode Level 2. Method 21 monitoring will be conducted on leaks identified by the Portable PIDs and Infrared Cameras. Confirmed emissions

sources that exceed regulatory requirements shall be repaired as soon as practicable. First attempt at repair of the confirmed emissions sources shall occur no later than 5 days from the date of source identification by the Investigation Team. Assessment of tanks shall be consistent with the protocols for tank monitoring in Appendix 2.7 of this Consent Decree.

Compliance Status Determination and Corrective Action

10. By no later than 14 days after identifying, through a Field Investigation, a benzene-emitting source(s) that caused or contributed to a Screening Condition, SDP shall determine whether the source is or was in violation of any applicable federal, state, or local regulations or permit requirements. SDP shall implement, as soon as practicable, corrective action to address any past or present noncompliance.

11. If the compliance status determination in Paragraph 10 reveals that an identified source(s) of benzene is not in violation of any applicable regulation or permit requirement, SDP shall evaluate the feasibility of reducing the emissions of benzene from that source in order to minimize the potential recurrence of a future Screening Condition from that source. In the Semi-Annual Reports required pursuant to this SOW, SDP shall describe in detail the evaluation that it took and identify any reduction measures considered, taken, and/or rejected.

Plans, Reports, and Schedule

12. No later than 120 days after the entry of this Consent Decree, SDP shall submit in writing to EPA for review and approval an Air Monitoring Response Plan for the Facility. This Plan shall include, but not be limited to:

a. A detailed description of the systems and equipment to be installed and operated to implement this SOW. The systems and equipment shall be consistent with the requirements set forth in Paragraphs 3 through 6 of this SOW.

b. A QAPP that SDP shall implement to ensure the accuracy, validity, representativeness, and usability of the data obtained by all monitoring equipment, including the AMS, portable PIDs, TVAs, and Infrared Cameras. The QAPP shall comply with the guidelines available in the following publication: "EPA Requirements for Quality Assurance Project Plans, EPA QA/R-5, March 2001."

c. Detailed standard operating procedures to be used during Field Investigations.

d. A schedule—with a start date contingent upon approval of the Air Monitoring Response Plan—for expeditiously purchasing, installing and commencing operation of the AMS, the DAS, the two Infrared Cameras, the two Portable PIDs, and the two TVAs .

13. After EPA has completed its review and approval of the Air Monitoring Response Plan, EPA shall send notice of its approval by certified mail, return receipt requested, to the individuals listed for SDP in the Notice Section of this Consent Decree. The "date of approval" of SDP's Air Monitoring Response Plan shall be three days after the date of EPA's mailing.

14. SDP shall purchase or lease the equipment specified in the approved plan in accordance with the schedule in the approved plan.

15. SDP shall complete the installation of all equipment specified in the Air Monitoring Response Plan in accordance with the schedule in the approved plan. SDP shall promptly notify EPA when all of the specified equipment has been installed. SDP shall not move the AMS to a new location without prior written approval by EPA. Movement of AMS components for maintenance shall not be restricted by this paragraph.

16. SDP shall commence operation of all monitoring equipment specified in the Air Monitoring Response Plan in accordance with the schedule in the approved plan.

17. No later than 180 days after the AMS is operational, SDP shall begin conducting Field Investigations into all Screening Conditions.

18. SDP may seek EPA approval to modify the Air Monitoring Response Plan at any time during the effective period of this Consent Decree.

19. SDP shall submit Air Monitoring Semi-Annual Reports to EPA that contain the following information:

   a. In spreadsheet format, all data collected by the AMS. Data shall include time-synchronized concentration data and meteorological data which shall be presented in contiguous columns on the spreadsheet. The first two columns of each sheet shall be the date and time.

   b. A detailed summary of each Field Investigation including:

      i. The pertinent data collected during the Field Investigation, including but not limited to: *(a)* measurement data collected by the AMS, *(b)* recorded emissions imaged by the Infrared Cameras, *(c)* portable PID data; *(d)* TVA data; and *(e)* process data related to the Investigation.

ii. A detailed description of any actions taken by SDP to bring sources into compliance and/or to reduce emissions in response to the findings of a Field Investigation.

c. The calibration, maintenance, and other QA/QC results prepared pursuant to the QAPP for all monitoring equipment required under this SEP.

d. In the period before the AMS is fully operational, SDP shall report on the progress toward implementing this SEP.

20. The Air Monitoring Semi-Annual Reports shall be submitted contemporaneously with the Semi-Annual Reports due under Paragraph 85 of the Decree with the first Air Monitoring Semi-Annual Report due on the first reporting date that occurs more than three months after the approved date for commencement of the operation of the AMS. The Air Monitoring Semi-Annual Report shall be certified in accordance with Paragraph 89 of the Consent Decree.

21. SDP shall post the Air Monitoring Semi-Annual Reports on the Internet, with any confidential information redacted, at that same time as submission to EPA.

22. On a calendar week basis, SDP shall post to a publicly available internet site the SDP Relevant Data for the prior week. SDP shall post the SDP Relevant Data for each calendar week no later than the last day of the following calendar week. The data shall be presented in form that allows the benzene, wind speed, and wind direction data to be viewed concurrently, i.e., in a tabular format.

23. On a calendar week basis, SDP shall e-mail the AMS and Meteorological Station data that does not meet the definition "SDP Relevant Data" for that week to Cary Secrest of EPA HQ (secrest.cary@epa.gov) and Dorothy Crawford of EPA Region 6 (crawford.dorothy@epa.gov). SDP shall e-mail the data for a calendar week no later than the last day of the following calendar week. The data shall be presented in form that allows the benzene, wind speed, and wind direction data to be viewed concurrently, i.e., in a tabular format.

24. SDP shall be required to correct deficient performance with the terms of this SOW. Any disputes related to this SOW shall be resolved pursuant to the procedures set forth in Section XII of this Consent Decree.

25. SDP shall comply with all terms of this Air Monitoring SOW and terms of the Air Monitoring Response Plan for a period of two years starting with the date that Field Investigations are required pursuant to Paragraph 17 above.

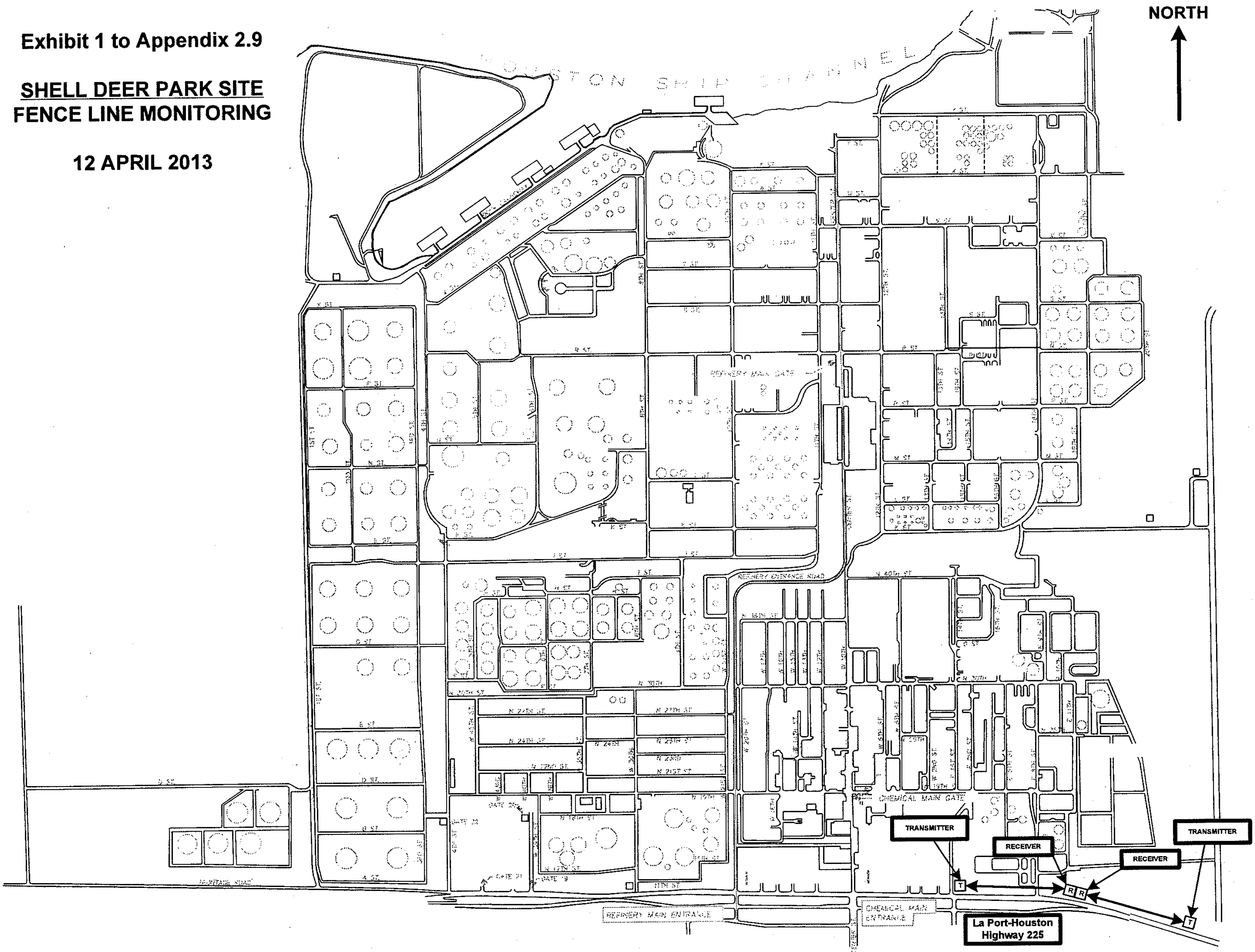
26. SDP shall submit to EPA a completion report on this SEP ("SEP Completion Report") at the time specified in Paragraph 81 of the Consent Decree. In addition to the information required in Paragraph 81, the SEP Completion Report for this SEP shall include: (i) the same information required in an Air Monitoring

Semi-Annual Report; (ii) a summary of violations identified in the process of implementing this SEP; and (iii) a summary of physical, process, and/or operational changes made as a result of implementing this SEP.

Exhibit 1 to Appendix 2.9

SHELL DEER PARK SITE
FENCE LINE MONITORING

12 APRIL 2013



UNITED STATES
v.
SHELL OIL COMPANY, ET AL.

APPENDICES TO CONSENT DECREE

APPENDIX 2.10

DIESEL RETROFIT SUPPLEMENTAL ENVIRONMENTAL PROJECT

APPENDIX 2.10

Supplemental Environmental Project: Diesel Retrofit

1. SDP shall implement a supplemental environmental project ("SEP") in accordance with the criteria, terms and procedures specified in this Appendix 2.10 and in Section VIII (Supplemental Environmental Projects).

2. SDP may carry out its SEP responsibilities directly or through contractors selected by SDP. SDP shall ensure that all contractor costs related to the SEP are reasonable and necessary for completion of the SEP.

3. SDP shall spend no less than Two-Hundred Thousand Dollars ($200,000) to implement this SEP, which is to reduce emissions generated by diesel-powered school buses and non-school bus publicly-owned vehicles in the area of SDP's refinery and chemical plant ("Covered Facilities") in Deer Park, Texas.

4. All SEP funds shall be spent on the purchase and installation of United States Environmental Protection Agency ("EPA") and/or California Air Resources Board ("CARB") verified retrofit and idle reduction technologies. SEP funds creditable toward meeting the minimum $200,000 expenditure shall cover only the hardware and installation cost of retrofit and idle reduction technologies.

5. All SEP funds shall be spent for technologies to be installed on school buses or publicly owned vehicles located within 50 miles of the Covered Facilities and, limited to, and in the order of, the following priorities:

(1) School buses in Harris County
(2) Non-school bus publicly owned vehicles in Harris County
(3) School buses in Brazoria, Chambers, Fort Bend, Galveston, Liberty, and Montgomery counties
(4) Non-school bus publicly owned vehicles in Brazoria, Chambers, Fort Bend, Galveston, Liberty, and Montgomery counties

6. Implementation of this SEP project shall be completed within twenty-four (24) months after the Date of Entry of this Consent Decree.

7. SDP shall seek to coordinate the selection of projects and the funding of projects with relevant and applicable state and local officials where possible, but SDP retains responsibility for performance of the SEP.