ADEQ

OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation No. 26:

Permit No. : 868-AOP-R2

IS ISSUED TO:

Lion Oil Co.

El Dorado, AR 71730

Union County

AFIN: 70-00016

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

December 12, 2000 AND December 11, 2005

IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Michael Bonds
Chief, Air Division

Date Modified

Table of Contents

SECTION I: FACILITY INFORMATION 4

SECTION II: INTRODUCTION 5

SECTION III: PERMIT HISTORY 39

SECTION IV: SPECIFIC CONDITIONS 43

SECTION V: PLANT WIDE CONDITIONS 163

SECTION VI: INSIGNIFICANT ACTIVITIES 184

SECTION VII: GENERAL PROVISIONS 186

Table 1 - List of Acronyms

A.C.A.	Arkansas Code Annotated
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CSN	County Serial Number
HAP	Hazardous Air Pollutant
lb/hr	Pound per hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
PM	Particulate matter
PM_{10}	Particulate matter smaller than ten microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Ton per year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

Section I: FACILITY INFORMATION

PERMITTEE:	Lion Oil Co.
AFIN:	70-00016
PERMIT NUMBER:	868-AOP-R2
FACILITY ADDRESS:	1000 McHenry Avenue
	El Dorado, AR 71730
MAILING ADDRESS	1000 McHenry Avenue
	El Dorado, AR 71730
COUNTY:	Union
CONTACT POSITION:	Mr. Chuck Hammock, Environmental Manager
TELEPHONE NUMBER:	(870) 864-1289
REVIEWING ENGINEER:	David Triplett
UTM North - South (Y):	Zone 15 3655.1
UTM East - West (X):	Zone 15 531.0

Section II: INTRODUCTION

Summary of Permit Activity

Lion Oil Co. owns and operates a petroleum refinery located in El Dorado, Union County, Arkansas. This will be the second modification to the Title V Operating Air Permit for this facility. This modification is being issued in order to allow for the following changes.

The facility has modified, or will be modifying several units, and installing new equipment in order to produce low-sulfur diesel fuel and gasoline to meet the new US EPA "Tier II" fuel sulfur requirements. The changes which occurred at the plant which are associated with the Tier II project are as follows:

- A new naphtha splitter will be installed in the refining process following the #7 Fluid Catalytic Cracking Unit (FCCU).

- The existing #10 Diesel Hydrotreater will be converted to treat FCC heavy naphtha.

- The #12 Unit Distillate Hydrotreater Stripper Reboiler Furnace (SN-843) will be retrofitted with new piping to allow it to serve as the #10 unit Stripper Reboiler Furnace. After further evaluation, this heater will remain in its present service. There was no emissions change with this modification.

- New non-fired heat exchangers have been installed in the #12 Unit to supply heat previously supplied by the #12 Distallate Hydrotreater Stripper Reboiler Furnace.

- A new diesel hydrotreater will be installed (No. 8 ULSD Hydrotreater) to replace the #10 Diesel Hydrotreater and to produce Ultra-Low Sulfur Diesel (ULSD).

- A wet gas scrubber (WGS) has been installed on the #7 FCCU Catalyst Regenerator Stack (SN-809) in order to reduce emissions of sulfur dioxide (SO_2) and particulate matter (PM/PM_{10}).

- New equipment and piping will be installed to handle wastewater from the No. 8 Unit and the WGS and to comply with NSPS QQQ where applicable.

- The catalyst utilized in the #9 CCR (SN-831) has been changed to improve hydrogen production.

- The sulfur recovery capacity of the Sulfur Recovery Plant (SN-844) will be increased to handle the increased sulfur removed from the fuel oil and gasoline.

- Three existing tanks (T-113, T-247, and T-372) will be converted from diesel to FCC gasoline and heavy naphtha service. SN-113 will be retrofitted with an external floating roof, and SN-247 and SN-372 will be retrofitted with internal floating roofs.

- The diesel throughput of the following tanks will increase: T-54, T-108, T-109, T-119, T-121, and T-122. No other changes have occurred at any of these tanks.

- Two new process heaters will be installed. One at the #7 FCC Naphtha Splitter Reboiler, and one at the No. 8 ULSD Hydrotreater. These two heaters have been permitted as SN-857 and SN-860.

- A new emission bubble has been added to the permit to simplify tracking of emissions associated with the Tier II clean fuels project. This bubble includes all emissions from fugitive sources associated with the Tier II project, as well as emissions from the tanks which were either modified, or experienced a throughput increase associated with the project. This source has been assigned SN-858. The tanks associated with the Tier II project were previously included in the refinery tanks bubble (SN-856). Permitted VOC emissions from SN-856 have been decreased by the amount of the most recent available data for past actual emissions from the Tier II tanks.

- The No. 1 Cooling Tower has been replaced with the new No. 8 Cooling Tower (SN-859). This change was necessary to provide for the increased process cooling water demands due to the new equipment associated with the Tier II changes. Although the No. 8 Cooling Tower has a higher cooling water handling capacity, permitted emissions will decrease with this change due to the use of drift eliminators for emissions control in the No. 8 tower.

The changes associated with the Tier II Clean Fuels Project will increase permitted emissions of nitrogen oxides (NO_x) and carbon monoxide (CO). Permitted emissions of sulfur dioxide (SO_2), volatile organic compounds (VOC), and particulate matter less than 10 microns in diameter (PM_{10}), will decrease as a result of these changes.

Additionally, the following changes have been made to the permit. These changes are not specifically associated with the tier II project, but were included in the permit at this time.

- Lion Oil has proposed to lower permitted CO emissions from the No. 7 FCCU Catalyst Regenerator Stack (SN-809) to comply with provisions of the Global Settlement Agreement between Lion Oil, the US EPA, and ADEQ. CO emissions from this source will be required to comply with limits of 500 ppmvd at 0% O_2 (1-hour average) and 100 ppmvd at 0% O_2 (365-day rolling average). This results in a very substantial decrease in permitted CO emissions from this source (10,463.1 tpy decrease).

- A new non-contact condenser has been installed on the Vacuum Distillation Unit (VDU). This change will virtually eliminate VOC emissions from the VDU. These VOC emissions were previously routed through the No. 1 cooling tower, and included in SN-852. This changes results in a decrease in permitted VOC emissions of 242.1 tpy. Small quantities of VOC may continue to be emitted from the VDU in the form of fugitive equipment leaks. Such emissions are covered by SN-858, the Tier II fugitives and tanks emissions bubble.

- Catalytic converters and air/fuel ratio controllers are being installed on the North 8 and

South 10 SVG compressors (SN-837 and SN-838) and the East and West JVG compressors (SN-839 and SN-840). These controls are being installed as an "supplemental environmental project" pursuant to paragraph 32(A) of the consent decree agreement between Lion Oil, the US EPA, and ADEQ. These controls are not being installed pursuant to "BACT" or any portion of the NSR or PSD programs. The installation of these controls will reduce emissions of NO_x and CO from these four compressor engines.

- A catalytic converter and air/fuel ratio controller is being installed on the air compressor (SN-841) pursuant to BACT requirements and paragraph 16(B)(ii) of the consent decree agreement. The installation of these controls will reduce emissions of NO_x and CO from this compressor engine.

- A continuous emissions monitor (CEM) system will be installed on the #4 Atmospheric Furnace (SN-804). This system will be installed in order to demonstrate compliance with an emission limit of 0.045 lb NO_x/MMBtu which was established pursuant to the global settlement agreement between Lion Oil Co., the US EPA, and ADEQ.

- Several new requirements have been added to the permit to clarify regulatory applicability and other administrative issues as required by the Global Settlement Agreement between Lion Oil, the US EPA, and ADEQ. No emissions changes result from these new permit conditions.

- As a result of the global settlement agreement, three of the existing boilers (SN-818, 819, 820) are now subject to the provisions of 40 CFR Part 60 Subpart J. Compliance with the NSPS requirements for H_2S concentration in the fuel gas results in a decrease in SO_2 emissions from these sources.

As a result of all of the modifications performed at the plant with this permit revision, overall permitted annual emissions limitations for the facility will change as follows: PM_{10} will decrease by 273.0 tpy, SO_2 will decrease by 2,338.8 tpy, VOC will decrease by 299.7 tpy, CO will decrease by 10,620.0 tpy, and NO_x will decrease by 89.2 tpy. There are no changes to any limits contained in the existing non-criteria pollutants bubble limits contained in this permit. The facility will be required to continue to demonstrate compliance with these limits.

PSD Applicability to the Tier II Project:

When considering possible applicability of the Federal Prevention of Significant Deterioration (PSD) regulations to the Tier II Clean Fuels Project, it is necessary to consider actual, rather than permitted emissions changes at the facility. Additionally, any emission decreases not associated with the Tier II Project (such as the CO reductions from the FCCU or the VOC reductions from the VDU) cannot be considered in the PSD applicability analysis. Furthermore, some sources may experience actual emission increases associated with this project without an accompanying increase in permitted emissions (such as the increased steam demand from the existing refinery boilers).

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

An analysis of the actual emission increases associated with the Tier II Clean Fuels Project at the Lion Oil facility shows that all emissions increases fall below the significance levels for PSD applicability. A detailed source-by-source summary of anticipated actual emission changes (actual-to-future potential) is provided below. For convenience, the emission changes have been summarized in a tabular format and organized by pollutant.

No_x Emissions Changes:

Source	Description	2001/2002 Actual Emissions (tpy)	Future Potential (permitted) emissions	Emissions Change (tpy)
SN-816 -- 820	Refinery Boilers*	N/A	N/A	10.8
SN-831	No. 9 CCR	4.4	8.8	4.4
SN-857, 860	Tier II Heaters	0.0	14.9	14.9
Total Tier II Project NO_x emission change				30.1

*** Additional steam will be required from the refinery boilers to supply the new Tier II project equipment, specifically the product stripper (part of the No. 8 unit). A maximum worst-case steam demand from new equipment has been calculated by Lion Oil as 9,322 lb/hr steam, with 4,862 lb/hr to the #8 ULSD hydrotreater product stripper, and an additional 4,462 lb/hr for steam tracing to the #12 amine trim heater and the #8 steam ejector. The 10.8 tpy increase in NOx emissions attributed to the boilers for the purposes of this PSD analysis is calculated based on the amount of combustion necessary to produce this 9,322 lb/hr increase in steam demand. Other increases in actual emissions from the refinery boilers may occur due to factors outside of the Tier II project, but such emissions are not applicable to this PSD analysis and such emissions are allowable under the existing terms of this permit. There are no changes to any physical, operational, or permit limits on the refinery boilers with this modification.**

CO Emissions Changes:

Source	Description	2001/2002 Actual Emissions (tpy)	Future Potential (permitted) emissions	Emissions Change (tpy)
SN-816 -- 820	Refinery Boilers*	N/A	N/A	3.2
SN-831	No. 9 CCR	4.4	11.4	7.0
SN-857, 860	Tier II Heaters	0.0	35.1	35.1
Total Tier II Project CO emission change				45.3

*** Additional steam will be required from the refinery boilers to supply the new Tier II project equipment, specifically the product stripper (part of the No. 8 unit). A maximum worst-case steam demand from new**

equipment has been calculated by Lion Oil as 9,322 lb/hr steam, with 4,862 lb/hr to the #8 ULSD hydrotreater product stripper, and an additional 4,462 lb/hr for steam tracing to the #12 amine trim heater and the #8 steam ejector. The 3.2 tpy increase in CO emissions attributed to the boilers for the purposes of this PSD analysis is calculated based on the amount of combustion necessary to produce this 9,322 lb/hr increase in steam demand. Other increases in actual emissions from the refinery boilers may occur due to factors outside of the Tier II project, but such emissions are not applicable to this PSD analysis and such emissions are allowable under the existing terms of this permit. There are no changes to any physical, operational, or permit limits on the refinery boilers with this modification.

SO_2 Emissions Changes:

Source	Description	2001/2002 Actual Emissions (tpy)	Future Potential (permitted) emissions	Emissions Change (tpy)
SN-816--820	Refinery Boilers[1]	N/A	N/A	12.4
SN-831	No. 9 CCR	4.4	8.8	4.4
SN-844	Sulfur Recovery Plant[2]	20.5	53.4	32.9
SN-809	No. 7 FCCU Catalyst Regenerator[3]	702.9	58.3	-35.0[4]
SN-857, 860	Tier II Heaters	0	14.4	14.4
Total Tier II Project SO_2 emission change				29.1

1 - Additional steam will be required from the refinery boilers to supply the new Tier II project equipment, specifically the product stripper (part of the No. 8 unit). A maximum worst-case steam demand from new equipment has been calculated by Lion Oil as 9,322 lb/hr steam, with 4,862 lb/hr to the #8 ULSD hydrotreater product stripper, and an additional 4,462 lb/hr for steam tracing to the #12 amine trim heater and the #8 steam ejector. The 12.4 tpy increase in SO_2 emissions attributed to the boilers for the purposes of this PSD analysis is calculated based on the amount of combustion necessary to produce this 9,322 lb/hr increase in steam demand. Other increases in actual emissions from the refinery boilers may occur due to factors outside of the Tier II project, but such emissions are not applicable to this PSD analysis and such emissions are allowable under the existing terms of this permit. There are no changes to any physical, operational, or permit limits on the refinery boilers with this modification.

2 – 2001/2002 actual emissions exclude emissions attributable to upset conditions.

3 – Past actual emissions from SN-809 are based on throughput records and past stack test data.

4 – Under the terms of paragraph 27(c)(ii) of the consent decree, the facility is allowed to claim no more than 35 tpy of SO_2 emissions reductions from controls installed pursuant to the consent decree. Actual emissions from this change will be reduced by 644.6 tpy, but only 35 tpy of this decrease is allowable for the purposes of PSD accounting.

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

PM_{10} Emissions Changes:

Source	Description	2001/2002 Actual Emissions (tpy)	Future Potential (permitted) emissions	Emissions Change (tpy)
SN-816--820	Refinery Boilers[1]	N/A	N/A	0.9
SN-831	No. 9 CCR	4.4	8.8	4.4
SN-844	Sulfur Recovery Plant	13.1	52.7	39.6
SN-809	No. 7 FCCU Catalyst Regenerator[2]	233.8	32.9	-10.0[4]
SN-857, 860	Tier II Heaters	0	9.5	9.5
SN-859	No. 1 Cooling Tower Replacement[3]	43.0	12.8	-30.2
Total Tier II Project PM_{10} emission change				14.2

1 - Additional steam will be required from the refinery boilers to supply the new Tier II project equipment, specifically the product stripper (part of the No. 8 unit). A maximum worst-case steam demand from new equipment has been calculated by Lion Oil as 9,322 lb/hr steam, with 4,862 lb/hr to the #8 ULSD hydrotreater product stripper, and an additional 4,462 lb/hr for steam tracing to the #12 amine trim heater and the #8 steam ejector. The 0.9 tpy increase in PM_{10} emissions attributed to the boilers for the purposes of this PSD analysis is calculated based on the amount of combustion necessary to produce this 9,322 lb/hr increase in steam demand. Other increases in actual emissions from the refinery boilers may occur due to factors outside of the Tier II project, but such emissions are not applicable to this PSD analysis and such emissions are allowable under the existing terms of this permit. There are no changes to any physical, operational, or permit limits on the refinery boilers with this modification.

2 – Past actual emissions from SN-809 are based on throughput records and past stack test data.

3 – The existing cooling tower bubble limit (SN-853) has been reduced by an amount equal to the past actual emissions from the No. 1 Cooling Tower, which has been replaced by the No. 8 Cooling Tower. This reduction will make enforceable the reduction in emissions from the removal of the No. 1 tower.

4 – Under the terms of paragraph 27(c)(ii) of the consent decree, the facility is allowed to claim no more than 10 tpy of PM_{10} emissions reductions from controls installed pursuant to the consent decree. Actual emissions from this change will be reduced by 200.9 tpy, but only 10 tpy of this decrease is allowable for the purposes of PSD accounting.

VOC Emissions Changes:

Source	Description	2001/2002 Actual Emissions (tpy)	Future Potential (permitted) emissions	Emissions Change (tpy)
SN-816—820	Refinery Boilers[1]	N/A	N/A	0.6
SN-854/858	Tier II Fugitive Equipment Leaks[2,3]	91.6	41.3	-50.3
SN-856/858	Tank 54[2]	19.7	38.1	18.3
	Tank 108[2]	0.9	1.1	0.2
	Tank 109[2]	0	1.1	1.1
	Tank 113[2]	25.3	14.1	-11.2
	Tank 119[2]	51.3	60.6	9.4
	Tank 121[2]	86.1	98.2	12.1
	Tank 122[2]	85.5	99.0	13.5
	Tank 247[2]	2.5	4.9	2.4
	Tank 372[2]	21.2	5.4	-15.8
SN-857, 860	Tier II Heaters	0	6.9	6.9
Total Tier II Project VOC Emissions Change				-12.8

1 - Additional steam will be required from the refinery boilers to supply the new Tier II project equipment, specifically the product stripper (part of the No. 8 unit). A maximum worst-case steam demand from new equipment has been calculated by Lion Oil as 9,322 lb/hr steam, with 4,862 lb/hr to the #8 ULSD hydrotreater product stripper, and an additional 4,462 lb/hr for steam tracing to the #12 amine trim heater and the #8 steam ejector. The 0.6 tpy increase in VOC emissions attributed to the boilers for the purposes of this PSD analysis is calculated based on the amount of combustion necessary to produce this 9,322 lb/hr increase in steam demand. Other increases in actual emissions from the refinery boilers may occur due to factors outside of the Tier II project, but such emissions are not applicable to this PSD analysis and such emissions are allowable under the existing terms of this permit. There are no changes to any physical, operational, or permit limits on the refinery boilers with this modification.

2 – A new bubble limit has been created for the Tier II fugitive equipment leak and tank emissions. All fugitive and tank emission sources associated with the Tier II project have been included in this new emissions bubble. Since the tanks included in the Tier II project are all existing tanks in use at the facility, which were previously included in the total tanks bubble (SN-856), the total tanks VOC limit has been reduced by an amount equal to the calculated past actual emissions from the Tier II tanks. Likewise, the existing fugitive

emissions bubble (SN-854) was reduced by an amount equal to the past two years actual emissions from fugitive sources now included in the Tier II fugitives and tanks bubble (SN-858).

3 – Past actual fugitive emissions are the past actual fugitive emissions from the No. 10 Diesel Hydrotreater. The No. 10 Unit is not currently subject to an LDAR program. However, upon conversion from Diesel to Naphtha service, the No. 10 Unit will become subject to at least the LDAR monitoring prescribed by NSPS Subpart GGG. After implementation of Subpart GGG monitoring as required, an emissions decrease in No. 10 unit fugitive emissions will result from the Tier II Clean Fuels Project. The fugitive emissions associated with the new naphtha splitter and the new No. 8 ULSD Hydrotreater are also included in the proposed fugitives/tanks emissions bubble (SN-858).

Process Description

#1 Crude Unit:

This unit, which included the #1 Crude Topping Furnace (SN-801) and the #1 Crude Vacuum Furnace (SN-802) was removed from service.

#4 Crude Unit:

This unit is designed to separate approximately 65,000 BPD of light straight run gasoline and crude oil into various components of naphtha, gasoline, kerosene, diesel, gas oils and asphalt. Crude entering the unit is preheated using heat exchangers and hot rundown streams from the unit and flashed in the Pre-flash Column to produce gasoline and naphtha. The Pre-flash Column Reboiler (SN-803) is a natural gas fired or desulfurized refinery gas fired furnace used to maintain the temperature in the column. Bottoms from the column are heated in the fuel gas fired Atmospheric Topping Furnace (SN-804) prior to distillation at atmospheric pressure. The Atmospheric Column further separates the crude into naphtha, kerosene, diesel, and gas oil. Bottoms from the column are heated in the fuel gas fired Vacuum Furnace (SN-805) prior to vacuum distillation. The Vacuum Column separates the bottoms into gas oil and asphalt products.

#7 Fluid Catalytic Cracking Unit:

This unit is designed to convert approximately 20,000 BPD of gas oil from the refinery crude units and other sources into more useful products. Gas oil entering the unit is first heated to 675°F in the #7 FCCU Furnace (SN-808) which is fired with desulfurized refinery fuel gas and equipped with low NO_X burners. The hot oil is then contacted with a hot (approximately 1350°F) fluidized catalyst which causes the gas oil to crack into lighter products. The catalyst is then separated from the products in the Reactor and returned to the Regenerator. In the Regenerator, coke which has deposited on the catalyst is burned off and the catalyst is recycled. The hot flue gas leaving the Regenerator passes through two (2) sets of cyclones to remove any catalyst fines and is then used to produce steam in the waste heat boiler. The hot gases are then cooled to less than 500F before exiting the #7 Catalyst Regenerator Stack (SN-809). The light products produced in the reactor are separated in the Fractionator Tower and used for various purposes. The FCCU Catalyst Regenerator Stack (SN-809) is equipped with a wet gas scrubber (WGS) for the control of SO_2 and PM_{10} emissions.

#8 ULSD Hydrotreater:

The new #8 unit is designed to process diesel, kerosene, gas oil, or light cycle oil. This unit makes ultra low sulfur diesel quality fuel from diesel feedstock by reducing the sulfur content to 15 ppm as mandated by the Tier II diesel sulfur regulations. Light cycle oil, diesel, kerosene, or gas oil is heated in the new Tier II heater (SN-860) and then reacted with hydrogen in the reactor. Bottoms from the reactor flow through a high and low pressure product separator where the unreacted hydrogen is separated from the product and recycled to the reactor. The high pressure hydrogen gas stream is passed through an amine absorber to remove hydrogen sulfide gases from the system for sulfur removal in the sulfur recovery plant and/or NaHS unit. The liquid from the low pressure separator is passed through a stripper to remove any residual hydrogen sulfide before the desulfurized product is sent to storage.

#9 Unit:

This unit is designed to process approximately 16,000 BPD of naphtha from the crude unit and upgrade it into higher octane products. The process is divided into the Unifiner and Platformer sections.

In the Unifiner section, naphtha is heated in the #9 Hydrotreater Furnace/Reboiler (SN-810) and reacted with hydrogen over a cobalt/molybdenum catalyst to convert the sulfur in the naphtha stream to hydrogen sulfide. The Reactor effluent is passed through the Separator and Stripper to remove the hydrogen and hydrogen sulfide. The Stripper bottoms are sent to the Platformer section for further processing.

In the Platformer section, the Stripper bottoms are heated in the #9 Reformer Furnace (SN-811) and passed over a platinum/iridium catalyst in the Reactor where the naphtha molecules are restructured to form high octane compounds. The Reactor effluent is sent to two (2) Separators where hydrogen is separated from the platformate and recycled. The platformate is then sent to the Stabilizer, heated by the #9 Stabilizer Reboiler (SN-812), where the low molecular weight gases are removed and sent to the Reformer fuel gas system. The bottoms from the Stabilizer are sent to gasoline storage.

The Continuous Catalyst Regeneration (CCR) section of the Platformer allows the unit to increase its yield of high octane product due to increased activity from the catalyst. During a normal operating cycle, platforming catalyst deactivates due to coke laydown. The CCR is a continuous regeneration process that allows the coked catalyst to be continuously regenerated, therefore decreasing downtime required to maintain efficient operation. The #9 Continuous Catalyst Regenerator (SN-831) continuously burns off the coke deposit and restores catalyst activity, selectivity, and stability to essentially fresh catalyst levels.

As a result of the catalytic reforming process, high carbon content coke is deposited on the catalyst. This catalyst is then pneumatically conveyed from the reactor section to the regeneration section of the unit. Coke content on the spent catalyst is typically 4-5%, but at times may be as high as 12%. The catalyst is regenerated with a recirculated gas stream that is typically controlled between 0.9% and 1.1% oxygen. The coke on the catalyst is oxidized and the regenerated catalyst leaves the regeneration zone at less than 0.2% coke. The catalyst then passes to subsequent zones in the regenerator to further condition the catalyst for use in the reactors. This gas leaving the regenerator is approximately 0.35% oxygen. Stoichiometrically, this equates to using approximately 50% excess oxygen in the regeneration process.

#10 Diesel Desulfurization Unit:

Upon completion of the Tier II Clean Fuels Project at the El Dorado Refinery, Lion Oil will utilize the #10 to desulfurize FCC gasoline. This unit will use a heavy cut of FCC gasoline as feed and will remove sulfur to levels that will yield overall concentrations of sulfur in Lion Oil's gasoline pool to 30 ppm to meet the Tier II Gasoline sulfur regulations. Heavy FCC gasoline is heated in the #10 hydrotreater furnace/reboiler (SN-813) and then reacted with hydrogen in the reactor. Bottoms from the reactor flow to the product separator where the unreacted hydrogen is separated from the product and recycled to the reactor. The product then flows to a flash drum where most of the hydrogen sulfide that was formed in the reactor is flashed off and sent to the #17 and #18 units for treatment. The liquid from the flash drum is passed through a stripper to remove any residual hydrogen sulfide before the desulfurized product is sent to storage.

#11 Deasphaltizing Unit:

Asphalt produced directly from the #4 Crude Unit is processed through this unit to separate light hydrocarbons from the asphalt to yield a product suitable for catalytic cracking and at the same time, produce an asphalt with desirable properties. The #11 Unit is designed to process approximately 7,000 BPD of asphalt. Flux from the Crude Units is pumped into the top of the Extraction Tower and a propane/butane solvent is pumped into the bottom of the Extraction Tower. The two materials flow countercurrent to each other in the Extraction Tower. The solvent and deasphalted oil are then sent through a series of Evaporators and a Stripper where the solvent is distilled and condensed for recycle to the Extraction Tower. The deasphalted oil is used as feed to the Catalytic Cracker. Asphalt from the bottom of the Extraction Tower is heated in the #11 Deasphaltating Furnace (SN-814) and is passed through the Flash Tower and Asphalt Stripper to remove any residual solvent. The asphalt product is then sent to the Asphalt Plant where it is blended with other products.

Asphalt Plant Blowing Stills:

The asphalt plant stores, blends, and loads various grades of asphalt, primarily for roofing and paving uses. In addition, the plant has three (3) "blowing stills" where air is blown through asphalt to give it properties which are beneficial for producing specialty asphalts and roofing asphalts. Associated with these stills are three (3) natural gas and desulfurized refinery fuel gas fired #16 Asphalt Blowing Furnaces (SN-825) which are used to maintain required temperatures during the blowing operation. The flue gas from the blowing stills is mostly air, mixed with some hydrocarbons. The flue gas is passed through a water scrubber to remove any globules of asphalt. Flue gas from the Scrubber enters the Fume Incinerator (SN-824) and any remaining hydrocarbons are destroyed. The hot flue gases from the Fume Incinerator are used to generate steam before being discharged to atmosphere.

#12 Distillate Hydrotreater:

This unit is a diesel and gas oil desulfurization unit with a design capacity to process 24,000 BPD. Its purpose is to produce on-road diesel quality fuel to meet the Clean Air Act standards. The light cycle oil from the #7 FCCU and the kerosene and diesel from the #4 Crude Unit is processed to reduce the sulfur content from approximately 2.0 weight percent to less than 0.05 weight percent. The unit is also used to hydrotreat gas oils to remove sulfur from the feed to the #7 FCCU.

The mixed feed flows through the heat exchange train and the #12 Distillate Hydrotreater Furnace (SN-842) before being reacted with hydrogen in the Reactor. The Reactor effluent flows through the heat exchange train with final cooling by an air fin cooler before flowing into the High Pressure Separator where the unreacted hydrogen is separated from the product and recycled to the Reactor. A small portion of the unreacted hydrogen stream is vented to the sour fuel gas system for treatment in the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit.

The liquid product is then flowed to the Low Pressure Separator where some of the hydrogen sulfide which was formed in the Reactor is flashed off and sent to the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit for treatment. The liquid from the Low Pressure Separator then flows through heat exchangers to the Stripper to remove any residual hydrogen sulfide. The liquid from the bottom of the Stripper is then cooled in the heat exchangers and the product air fin cooler before being sent to storage. The Stripper off gas is cooled in an air fin cooler and compressed before being mixed with the High Pressure Separator vent stream and the off gas from the Low Pressure Separator. This combined off gas stream is sent to the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit for treatment. The makeup hydrogen to the unit is supplied from two (2) compressors which also compress the recycled hydrogen and the Stripper off gas. These compressors are driven by electric motors. All emergency releases are routed to the existing refinery flare system.

Boilers:

Lion Oil has six (6) fuel gas fired boilers which produce steam for the refinery. Boilers #9 (currently out of service), #10, and #11 (SN-816, SN-817) are low pressure boilers each of which produce 60,000 pounds per hour of 150 psig steam. Boilers #12, #13, and #14 (SN-818, SN-819, and SN-820) are high pressure boilers each of which produce 100,000 pounds per hour of 275 psig steam. All of the boilers are normally fired with refinery fuel gas. However, in the event that fuel gas is unavailable, the boilers can be fired with fuel oil.

Sour Water Stripper:

The refinery generates numerous water streams from storage tanks and accumulators that contain high concentrations of hydrogen sulfide and ammonia. The Sour Water Stripper (SWS) is a trayed column which is used to steam strip the hydrogen sulfide and ammonia from the sour water streams before the water is discharged into the refinery waste water treatment system. The sour gases that are stripped from the water are directed to a Claus combustor/thermal reactor to recover sulfur in the form of hydrogen sulfide from sour water stripper offgas.

#18 Sodium Hydrosulfide Unit:

Several processes in the refinery produce gases which cannot be reprocessed and sold as liquid propane gas (LPG) or gasoline. These gases are generally methane, ethane, and hydrogen produced from catalytic cracking and the reforming of petroleum fractions. As these light fractions are separated from other heavier gases, hydrogen sulfide is separated with the light gases, making the gas sour. In order to use this gas as fuel for refinery furnaces and boilers, the hydrogen sulfide must be removed to prevent excess SO_2 emissions as the fuel is burned.

The #18 Sodium Hydrosulfide Unit is used to remove the hydrogen sulfide from the fuel gas. The unit removes hydrogen sulfide by contacting the gas with caustic soda to form sodium hydrosulfide which is sold to paper mills to be used as a delignifying agent. The fuel gas leaving the unit then flows to the #17 Unit where it is contacted with amine. This unit removes hydrogen sulfide to below the levels of 40 C.F.R. 60, Subpart J. The fuel gas is used as fuel in refinery furnaces and boilers. Any SO_2 emissions to the atmosphere are accounted for in the individual emissions for the boilers and furnaces and the Sodium Hydrosulfide Unit is not itself an emission source.

<u>#17 Sulfur Recovery Plant:</u>

The purpose of the Sulfur Recovery Plant is to recover sulfur, up to 100 LTD (long tons per day), as hydrogen sulfide from fuel gas and off-site natural gases from Great Lakes Chemical to meet refinery New Source Performance Standards (NSPS - Subpart J) for process fuel gases (less than 0.1 grains H_2S). In addition, Sour Water Stripper (SWS) off gas can be treated in the Sulfur Recovery Plant. The hydrogen sulfide is converted to a salable elemental sulfur product. The Sulfur Recovery Plant is also used to convert ammonia from SWS off gas to diatomic nitrogen and water. The Sulfur Recovery Plant can be divided into three (3) process units:

- Amine Unit consisting of two (2) amine contactors
- Sulfur Recovery Unit (SRU) (Claus)
- Tail Gas Treating Unit (TGTU)

Sour gas enters the primary amine unit where it is contacted with amine. The amine removes hydrogen sulfide and some carbon dioxide from the sour fuel gas stream. The sweetened gas exits the primary amine unit for distribution throughout the refinery. Hydrogen sulfide and carbon dioxide are stripped from the amine which creates a hydrogen sulfide rich gas (acid gas) stream. The acid gas is then sent to the SRU.

Acid gas from the primary amine unit and recirculated gas from the TGTU, along with SWS off gas, enter the SRU and go directly to the Claus Combustor/Thermal reactor. This is where approximately one-third of the hydrogen sulfide is converted to sulfur dioxide. Ammonia in the SWS off gas is converted to diatomic nitrogen and water at the Claus reactor. The hot vapor products leaving the thermal reactor make several passes through the sulfur condenser and the catalytic reactors. The sulfur condenser separates the condensed sulfur from the vapor and removes it to storage. The catalytic reactors further promote the reaction of hydrogen sulfide and sulfur dioxide to sulfur and water vapor. The remaining gas exits the SRU to the TGTU. The purpose of the TGTU is to recover sulfur from the SRU tail gas. The sulfur compounds are hydrogenated to hydrogen sulfide in the TGTU reactor. The vapor products from the reactor are then cooled and directed to the TGTU amine unit which operates much like the primary amine unit. The amine stripper off gas is recirculated to the SRU feed and the amine absorber off gas is directed to the Sulfur Recovery Plant catalytic incinerator (SN-844). The remaining low concentrations of hydrogen sulfide, carbon monoxide, and hydrogen are combusted in the incinerator.

Flares:

The refinery operates a High Pressure Flare (SN-822) and a Low Pressure Flare (SN-823) for disposing of excess combustible gases. These gases result from undetected leaks in operating equipment, upset conditions in the normal operation of a refinery where gases must be vented to avoid dangerously high pressure in operating equipment, plant start-ups, and emergency shutdowns. The flares are identical John Zink "smokeless" flares which use steam aspiration to control visible emissions. In addition to excess refinery gases, each flare burns approximately 1,406 scf/hr of natural gas for the pilot burners.

In conjunction with the flares, the refinery operates a flare gas recovery system (FGRS). The FGRS draws excess flare gases from the flare gas header upstream of a liquid seal vessel and recovers gas that would otherwise be burned in the flares. The capacity of the FGRS is automatically varied to maintain a positive pressure on the flare header upstream from the liquid seal vessel. Maintaining a positive pressure ensures that the air is not drawn into either the flare system or the flare gas recovery system. If the volume of the gas in the flare header exceeds the capacity of the FGRS, the excess gas will vent through the water seal on the FGRS to the flares.

Cellulose Fiber Baghouse:

The refinery operates an asphalt protective coatings unit. Cellulose fibers are received in bags and added to the system via a negative pressure hood and conveyor system. Any exhaust from the system is filtered through the Asphalt Protective Coating Baghouse (SN-807). Based on information submitted by Lion Oil in a letter dated July 25, 2002, this source has been moved to the insignificant activities list.

Truck Loading Racks:

The refinery operates several truck and rail loading racks. Products loaded range from asphalt to propane. The main truck loading rack is an automated bottom loading rack (SN-846) for loading transport trucks with all grades of gasoline and diesel. Emissions from all other loading racks are accounted for in the Heavy Oil Loading Racks (SN-847). Vapors generated at the gasoline/diesel loading rack during the loading operations are routed through a knock-out pot where any free liquids are recovered and the vapors are vented to a vapor recovery unit.

Gas Engine Compressors:

The refinery operates eight (8) internal combustion gas compressor engines (SN-834 through SN-841). The compressors operate on natural gas and are utilized in moving gases within refinery applications.

Hydrocarbon Storage Tanks:

The refinery operates numerous hydrocarbon storage tanks which store products ranging from asphalt to propane.

Steam Superheater Furnace:

The refinery operates two (2) steam turbine driven gas compressors which consume 25,000 pounds per hour of superheated steam. The Steam Superheater Furnace (SN-829) heats steam from the boilers to approximately 695°F prior to the compressor turbine inlet. The furnace operates on pipeline quality natural gas and desulfurized refinery fuel gas and has a design heat input of 10.0 MMBtu/hr.

#5 Alkylation Unit:

There are two (2) 1,500 barrel (BBL) steel tanks which are used for storing 99% sulfuric acid which is used as a catalyst in this unit. The charge to this unit is approximately 6,000 BPD. The acid is diluted to 90% and then pumped to two (2) 2,000 barrel (BBL) spent acid tanks. Two (2) Acid Fume Scrubbers (SN-826 and SN-827) packed with polypropylene saddles are used to scrub any vapors which may be generated from the tanks during loading and transfer operations. These sources (SN-826 and SN-827) have been moved to the insignificant activities list.

Asphalt Rack Steam Heater:

Various grades of asphalt which are used for paving are produced at the refinery. A natural gas and desulfurized refinery fuel gas fired package boiler rated at 10 MMBtu/hr (SN-828) is used to heat asphalt products during the truck loading operation.

#6 Hydrotreater/Isomerization Unit:

This unit has been installed due to EPA's lead phase down regulation. The unit upgrades light straight run naphtha from the crude unit into a higher octane gasoline. It consists of a hydrotreater section and a penex isomerization section. In the hydrotreater, light straight run naphtha from the crude units is heated in the #6 Hydrotreater Furnace/Reboiler (SN-806) and reacted with hydrogen over a nickel/molybdenum catalyst to convert the sulfur in the light straight run naphtha stream to hydrogen sulfide.

The reactor effluent is passed through the separator and stripper to remove hydrogen and hydrogen sulfide. The stripper bottoms are sent to the penex isomerization section for further processing. Here, the stripper bottoms are heated in the isomerization heater and passed over a platinum catalyst in the reactor where the light straight run naphtha molecules are restructured to form higher octane compounds. The reactor effluent is sent to a separator where hydrogen is separated from the isomerate and recycled. The isomerate is then sent to the stabilizer where the low molecular weight gases are removed through a caustic scrubber and sent to the refinery fuel gas system. The bottoms from the stabilizer are sent to gasoline storage.

Asphalt Tank Heaters:

The refinery operates forty-seven (47) asphalt tank heaters (SN-832) which are fired by either natural gas or desulfurized refinery fuel gas.

<u>Wastewater Treatment Plant:</u>

This unit uses a combination of chemical, biochemical, and physical processes to remove pollutants from refinery wastewater before discharging into DeLoutre Creek. The main components of the unit are dual API separators, two (2) equalization tanks and pond, a dissolved air flotation (DAF) unit, a cooling tower, two (2) activated sludge bio-reactors, two (2) clarification tanks, sludge recycle equipment, an aerobic digester, and a sludge thickener. Final effluent filters assure a minimum level of suspended matter in the effluent discharged to DeLoutre Creek.

Final effluent cooling towers cool the effluent prior to discharge. Sludges generated at the Waste Water Treatment Plant are dewatered at the Sludge Management Facilities (SMF) prior to effluent disposal.

The facility is currently in the process of constructing a new, totally enclosed system for the handling and treatment of process wastewater. This new system will allow for the segregation of process wastewater from refinery stormwater. VOC emissions from wastewater treatment at the facility should be greatly reduced once the new system is completed and operational. Once the new system is completed, the existing system will be converted to stormwater-only use.

<u>Lime Silo:</u>

Lime used in the SMF is stored in a lime silo. This silo is equipped with a baghouse (SN-845) which controls emissions during periods of filling. Based on information submitted by Lion Oil in a letter dated July 25, 2002, the Lime Silo Baghouse (SN-845) has been moved to the insignificant activities list.

<u>Polymer Asphalt Letdown Facility:</u>

This unit, which includes SN-850, is designed to produce a performance graded polymer modified asphalt binder for the asphalt paving industry. The unit consists of a refinery fuel gas-fired heater with a design nominal firing rate of 20 MMBtu/hr based on the HHV, a hot oil circulating pump, a heat exchanger, storage tanks, and loading racks. The hot oil circulates through coils in the storage tanks to maintain the final product in a fluid and transportable state. The heat exchanger is included in the hot oil system to keep the neat asphalt in a fluid state during the PMA blending operations.

<u>Fugitive Emissions from Equipment Leaks:</u>

Fugitive emission sources include leaks of hydrocarbon vapors from process equipment and evaporation of hydrocarbons from open areas, rather than a stack or vent. Fugitive emission sources include valves of all types, flanges, pump and compressor seals, wastewater collection, cooling towers, and oil/water separators.

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

Miscellaneous Operations:

Catalyst used in the #7 FCCU is stored in two hoppers, which exhaust through the #7 FCCU Catalyst Hopper Vent (SN-848). The hoppers are filled by "sucking" the catalyst into the hoppers. Each of the hoppers are equipped with eductors which reduce the pressure in the hoppers during the filling operation.

PSD Review History Summary:

PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
*Sources without old source numbers were previously unpermitted.		
37	T-3	1950
38	T-4	1953
40	T-11	1959
41	T-12	1955
42	T-14	1942
43	T-15	1942
44	T-16	1950
45	T-17	1940
46	T-18	1949
47	T-20 scheduled for removal	1945 2004
48	T-21 scheduled for removal	1945 2004
49	T-22	1953
50	T-23	1953
52	T-25	1940
54	T-27	1950
55	T-36	1953
56	T-39	1958
57	T-40	1940
58	T-41	1940
59	T-46	1933
60	T-48	1923
61	T-49	1923
62	T-50	1937
63	T-51	1940
65	T-54	1922
66	T-55	1923
67	T-56	1923

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
68	T-57	1949
69	T-58	1952
70	T-60	1923
71	T-61	1949
72	T-62	1949
73	T-63	1957
74	T-64	1957
75	T-65	1954
76	T-70	1935
77	T-71	1935
78	T-72	1950
79	T-73	1950
80	T-74	1950
81	T-76	1938
82	T-77	1945
84	T-81	1936
86	T-83	1938
87	T-84	1953
88	T-85	1954
90	T-89	1948
91	T-96	1940
92	T-97	1940
93	T-98	1940
94	T-99	1940
95	T-101	1922
96	T-102	1922
98	T-104	1923
99	T-105	1923
100	T-107	1923
103	T-110	1928
104	T-111	1936
105	T-112	1923
107	T-114	1923
108	T-115	1923
109	T-116	1923
110	T-117	1923
111	T-118	1944
112	T-119	1940
	T-120	1949
113	T-121	1949
114	T-122	1953
	T-123	1949

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
115	T-124	1959
116	T-125	1953
117	T-126	1953
118	T-128	1959
119	T-129	1937
120	T-145	1950
121	T-162	1951
122	T-165	1923
123	T-166	1923
124	T-167	1940
125	T-168	1940
126	T-170	1950
127	T-171	1950
128	T-173	1945
129	T-175	1940
130	T-176	1940
	T-180	1959
131	T-190	1940
	T-199	1957
132	T-200	1936
133	T-217	1964
134	T-219	1967
135	T-226	1936
136	T-228	1936
137	T-240	1953
138	T-241	1953
139	T-242	1953
140	T-243	1953
141	T-244	1953
142	T-245	1953
143	T-246	1953
144	T-247	1959
145	T-262	1938
146	T-263	1938
147	T-264	1938
148	T-265	1938
149	T-270	1941
150	T-271	1941
154	T-306	1952
155	T-310	1950
	T-311	1950
	T-312	1950
	T-313	1950

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
	T-314	1950
	T-315	1950
156	T-319	1950
157	T-320	1950
158	T-321	1950
159	T-322	1950
160	T-323	1950
162	T-325	1950
163	T-326	1950
164	T-327	1950
165	T-328	1950
166	T-329	1950
167	T-330	1950
168	T-331	1950
169	T-332	1950
170	T-333	1950
171	T-335	1950
	T-336	1950
172	T-337	1950
173	T-338	1950
174	T-339	1950
175	T-340	1961
176	T-348	1968
177	T-349	1968
178	T-350	1954
179	T-351	1954
180	T-352	1954
181	T-353	1954
182	T-354	1954
183	T-355	1959
184	T-356	1961
185	T-360	1957
186	T-361	1957
187	T-368	1966
188	T-371	1959
189	T-372	1959
191	T-410	1945
192	T-411	1945
193	T-412	1945
194	T-413	1945
	T-414	1945
195	T-429 demolished	1945 1999

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

PSD Review Source in Existence Prior to PSD Effective Date		
Old Source Numbers*	New Source Numbers	Year Installed
	T-520	1950
	T-521	1950
196	T-524	1951
	T-525	1951
197	T-530	1951
	T-570	1959
01	801 shut down	1930 1986
02	802 shut down	1960 1986
07	807	1977
09	809	1973
13	813	1958
16	816**	1945
17	817**	1945
18	818**	1952
19	819**	1952
20	820**	1958
23	823	1974
24	824	1977
25	825	1945/1946
	833	1959
	834	1942
	835	1942
	837	1958
	838	1958
	839	1959
	840	1959
	847	Pre-1950[1] Pre-1950[2] 1975[3] Pre-1950[4] Pre-1950[5]
	848	1973

**The previously permitted emissions for the #10, #11, #12, #13, and #14 Boilers, (SN's 816-820) were based upon the emission factors reported in the 1975 Second Edition of AP-42. An average emission factor of 175 lbs/10^6 ft^3 was used from the reported range of emission factors given for NO_X. The emission factor used to permit NO_X in this permit was based upon emission factors reported in the 1995 Fifth Edition of AP-42. The emission factor used for permitting NO_X is 280 lbs/10^6 ft^3.

[1] 111/219 West Truck Rack
[2] South Asphalt Plant Truck Rack
[3] PMA Plant Truck Rack (formerly known as the Emulsion Plant Truck Rack)
[4] Pumphouse Truck Rack
[5] E & W Rail Car Rack

The following sources were installed or modified after the effective date of the PSD regulations; however, the emission increases did not exceed the significance levels and PSD review would not have been required.

PSD Review Sources Installed After the Effective Date of PSD			
Old Source Numbers	New Source Numbers	Year Installed	Associated Emission Increase
*Sources without old source numbers were previously unpermitted. **Emission increase was determined by multiplying the lb/hr by 4.38. ***These were the emissions permitted in Permit #868-AR-5.			
83	T-78	installed 1950 replaced 1999	5.0 tpy VOC
89	T-88	1987	1.21 tpy VOC
97	T-103	1995	22.78 tpy VOC**
101	T-108 modified	1934 1982	4.38 tpy VOC**
102	T-109 modified	1934 1982	4.38 tpy VOC**
106	T-113 modified	1923 1995	4.38 tpy VOC**
	T-142	1982	4.38 tpy VOC**
	T-143	1982	4.38 tpy VOC**
151	T-272	1986	0.25 tpy VOC
152	T-273	1986	0.25 tpy VOC
153	T-274	1986	5.29 tpy VOC
161	T-324	1992	0.97 tpy VOC
190	T-384 modified	1974 1999	1.9 tpy VOC**
	T-432	1978	28.03 tpy VOC**
198	T-532	1981	35.98 tpy VOC
199	T-538	1989	0.25 tpy VOC
200	T-539	1989	0.25 tpy VOC
201	T-540	1987	0.25 tpy VOC
202	T-544	1991	1.11 tpy VOC
203	T-548	1993	19.01 tpy VOC
	T-549	1994	4.38 tpy VOC**
	T-550	1985	4.38 tpy VOC**

PSD Review Sources Installed After the Effective Date of PSD			
	T-551	1994	4.38 tpy VOC**
	T-552	1996	16.0 tpy VOC
	T-600	1994	4.38 tpy VOC**
	T-601	1994	4.38 tpy VOC**
	T-602	1994	4.38 tpy VOC**
	T-603	1995	4.38 tpy VOC**
	T-604	1994	4.38 tpy VOC**
	T-605	1996	4.38 tpy VOC**
	T-606	1996	4.38 tpy VOC**
	T-607	1990	4.38 tpy VOC**
	T-608	1987	4.38 tpy VOC**
	T-609	1995	4.38 tpy VOC**
	T-610	1980	4.38 tpy VOC**
	T-611	1995	4.38 tpy VOC**
	T-612	1995	4.38 tpy VOC**
03	803	1979	2.2 tpy PM*** 4.4 tpy SO2 30.7 tpy NOX 0.5 tpy VOC 3.1 tpy CO
04	804	1991	9.2 tpy PM 24.5 tpy SO2 39.42 tpy NOX 2.63 tpy VOC 15.77 tpy CO
05	805	1996	2.2 tpy PM 39.5 SO2 1.3 tpy VOC 29.5 tpy CO 39.5 tpy NOX
06	806 modified	1958 1988	25.4 tpy SO2 7.88 tpy PM 17.52 tpy NOX 1.75 tpy CO
08	808	1979	2.2 tpy PM/PM10*** 5.7 tpy SO2 25.0 tpy NOX 0.9 tpy VOC 4.0 tpy CO
11	811	1980	6.1 tpy PM/PM10*** 0.5 tpy SO2 1.8 tpy VOC 10.1 tpy CO 59.6 tpy NOX1
22	822	1979	0.5 tpy PM/PM10*** 117.8 tpy SO22 3.5 tpy VOC 18.8 tpy CO 83.7 tpy NOX2

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

PSD Review Sources Installed After the Effective Date of PSD			
26	826	1982	0.5 tpy SO2***
27	827	1982	0.5 tpy SO2***
28	828	1987	0.5 tpy PM/PM10*** 0.5 tpy SO2 0.5 tpy VOC 0.9 tpy CO 7.9 tpy NOX
29	829	1987	0.5 tpy PM/PM10*** 0.9 tpy SO2 0.5 tpy VOC 0.9 tpy CO 7.5 tpy NOX
30	830	1987	0.5 tpy PM/PM10*** 0.5 tpy SO2 0.5 tpy VOC 0.5 tpy CO 1.8 tpy NOX
31	831	1991	1.75 tpy SO2 1.75 tpy NOX 4.82 tpy CO 48.2 tpy HCl
34	842	1993	2.2 tpy PM/PM10 5.3 tpy SO2 0.5 tpy VOC 3.5 tpy CO 17.5 tpy NOX
35	843	1993	1.3 tpy PM 3.5 tpy SO2 11.8 tpy NOX 0.5 tpy VOC 2.2 tpy CO
36	844	1994	13.2 tpy PM/PM103 39.4 tpy SO2 250 ppm SO2 26.3 tpy NOX 6.6 tpy VOC 35.5 tpy CO 2.2 tpy H2S
32	832 (47) Asphalt Tank Heaters		15.8 tpy VOC
	Heats Tank SN	---	

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

PSD Review Sources Installed After the Effective Date of PSD			
	T-24 T-39 T-40 T-41 T-56 T-78 T-99 T-107 T-111 T-118 T-219 T-348	1975 pre-1981 1988 1991 1989 1999 1991 1987 pre-1981 1987 1968 1968	
Continued	T-354 T-384 T-524 T-530 T-544 T-548	1956 1975 1986 1986 1991 1993	
33	836	1986	1.0 tpy PM/PM10 1.0 tpy SO2 1.0 tpy VOC 34.2 tpy CO 39.6 tpy NOX Note: These are based on numbers in Permit #868-AOP-R0.
33	841	1981	1.0 tpy PM/PM10 1.0 tpy SO2 1.0 tpy VOC 58.3 tpy CO 79.7 tpy NOX4 Note: These are based on numbers in Permit #868-AOP-R0.
	845	1994	1.0 tpy PM/PM10
204	846	1980	Increase 727 tpy VOC Decrease 947 tpy VOC Net Change -220 tpy VOC The increase in emissions from the installation of the loading rack was offset by the removal of another loading rack. The modification took place while EPA Region VI was responsible for PSD review in the State of Arkansas.
	847	1987 1989 1986	1.8 tpy VOC5, 10 1.0 tpy VOC6 1.0 tpy VOC7
	849	1998	1.4 tpy PM10 1.2 tpy SO2 1.6 tpy VOC 11.6 tpy CO 19.2 tpy NOX

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

PSD Review Sources Installed After the Effective Date of PSD			
Polymer Asphalt Let-Down Facility		All Sources Modified 1999	1.8 tpy PM108 3.2 tpy SO2 15.8 tpy VOC 4.6 tpy CO 18.4 tpy NOX
	T-24 T-384 T-385 T-386 T-387 T-553 T-554 847 850		1.8 tpy VOC 1.8 tpy VOC 1.8 tpy VOC 1.8 tpy VOC 1.8 tpy VOC 1.5 tpy VOC Inorganics 4.3 tpy VOC 1.0 tpy VOC
Sour Water Stripper Project		2000	1.1 tpy PM10 1.1 tpy SO2 1.4 tpy VOC 12 tpy CO 27.2 tpy NOX
	T-7 816 817 818 819 820 844		
#4 Crude Unit Turnaround Improvements		2000	0.4 tpy PM10 1.9 tpy SO2 17.1 tpy VOC 6.5 tpy CO 3.9 tpy NOX
	T-39 T-40 T-41 T-55		
	T-84 T-121 T-122 T-219 T-368 803 804 805 814 847		

1 Construction commenced before the effective date of PSD. Additionally, subsequent increases in emissions were below PSD trigger limits.
2 Construction commenced before the effective date of PSD. This flare replaced two other high pressure flares.
3 This compressor engine replaced three existing gas air compressors.
4 111/219 East Truck Rack
5 North Asphalt Plant Truck Rack
6 Lube Oil Truck Rack

7 The facility added a Polymer Asphalt Let-Down facility in 1999. Equipment affected by this project included the modification of tanks T-24, and T-384 through T-387, the installation of tanks T-553 and T-554, the increased use of the PMA Asphalt Truck Rack (SN-847) and the installation of the asphalt hot oil heater (SN-850). Tanks T-385 through T-386 were removed from service and permanently classified as out-of service during the early 1980's, but were put back into service for this project. The total permitted emissions for these sources is 1.8 tpy PM/PM10, 3.2 tpy SO2, 15.8 tpy VOC, 4.6 tpy CO, and18.4 tpy NOX (no netting performed). In order to process the PMA project as a minor modification, the north and south PMA racks were limited to a total throughput of 1.2 million bbl/year. Emissions from the North and South PMA Racks are included in the heavy oil loading rack PAL.
8 The Sour Water Stripper Project was reviewed to ensure that it did not trigger PSD at the Sulfur Recovery Plant. The actual increase in emissions that would affect the Sulfur Recovery Plant was less than 1.0 tpy SO_2. The Sulfur Recovery Plant is monitored by a CEMS unit which is used to demonstrate compliance with the NSPS standards and to demonstrate that the facility does not exceed the SO2 emissions for SN-844.
9 There is a 99.1 tpy increase in permitted VOC emissions at the Heavy Oil Loading Rack (SN-847) from Permit #868-AR-7 to the Title V. This increase is not subject to PSD review. During the comment period for Permit #868-AR-5, was issued in 1996, the facility had attempted to update the emissions from this source based on updated information. No revisions or physical changes had occurred. A decision was made by the Department at that time to wait until the issuance of the Title V permit to make any updates to the emissions. The throughput limit for this loading rack has increased by 900 Mgal/yr from the previous permits. The only other change has been the methods of calculation.

Regulations

The following table contains the regulations applicable to this permit.

Table 2 - Regulations

Regulation
Regulation 18 – *The Arkansas Air Pollution Control Code*
Regulation 19 – *The Arkansas Plan of Implementation for Air Pollution Control*
Regulation 26 – *Regulations of the Arkansas Operating Air Permit Program*
40 CFR Part 60 Subpart Dc – *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units** (Appendix D)
40 CFR Part 60 Subpart J – *Standards of Performance for Petroleum Refineries** (Appendix C)
40 CFR Part 60 Subpart Ka – *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984** (Appendix A)
40 CFR Part 60 Subpart Kb – *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984** (Appendix B)

40 CFR Part 60 Subpart QQQ – *Standards of Performance for Petroleum Refinery Wastewater Systems** (Appendix J)
40 CFR Part 60 Subpart UU – *Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture** (Appendix H)
40 CFR Part 60 Subpart VV – *Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry** (Appendix G)
40 CFR Part 60 Subpart GGG – *Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries** (Appendix F)
40 CFR Part 61 Subpart FF – *National Emission Standards for Benzene Waste Operations** (Appendix E)
40 CFR Part 63 Subpart CC – *National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries** (Appendix I)
40 CFR Part 63 Subpart UUU – *National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units***

*** The Requirements of this permit are not intended to alter any applicable federal requirements.**

**** The facility will be subject to this rule after the applicable compliance date.**

The following table is a summary of emissions from the facility. The following table contains cross-references to the pages containing specific conditions and emissions for each source. This table, in itself, is not an enforceable condition of the permit.

Table 3 – Emission Summary

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates lb/hr	Emission Rates tpy	Cross Reference Page
Total Allowable Emissions		PM_{10}	176.1	596.5	
		SO_2	252.6	792.5	
		VOC	3,389.9	16,139.1	
		CO	616.2	1,524.6	
		NO_x	555.3	1,637.8	
HAPS		Benzene*		67.9	N/A
		Biphenyl*		9.5	
		1,3 Butadiene*		5.1	
		Carbon Disulfide		4.4	
		Carbonyl Sulfide		4.5	
		Cresol (mixed isomers)*		14.0	
		Cumene*		10.2	
		Diethanolamine*		4.4	
		Ethyl benzene*		43.6	
		Hexane*		314.5	
		Naphthalene*		6.6	
		Phenol*		9.8	
		Toluene*		148.7	
		2,2,4 Trimethylpentane*		56.2	
		Xylene (mixed isomers)*		341.8	
		Chlorine		26.7	
		Hydrogen Chloride		48.6	
		Formaldehyde*		4.9	
		H_2SO_4 (Sulfuric Acid)		88.3	
		H_2S		364.3	
Air Contaminants		Ammonia		62.1	
		Perchloroethylene (tetrachloroethylene)		7.1	
		Particulate Matter		884.3	
801	#1 Crude Topping Furnace	Removed from Service			
802	#1 Crude Vacuum Furnace	Removed from Service			

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
803	Pre-flash Column Reboiler	PM_{10} SO_2 VOC CO NO_x	1.0 1.7 1.0 4.3 7.3	4.4 5.9 4.4 14.5 24.6	45
804	#4 Atmospheric Furnace (Topping)	PM_{10} SO_2 VOC CO NO_x	2.2 9.7 1.6 23.7 12.9	7.3 32.6 5.2 80.1 43.7	45
805	#4 Vacuum Furnace	PM_{10} SO_2 VOC CO NO_x	1.0 3.3 1.0 8.0 7.9	4.4 11.1 4.4 27.1 26.7	45
806	#6 Hydrotreater Furnace/Reboiler	PM_{10} SO_2 VOC CO NO_x	1.0 1.3 1.0 3.2 5.5	4.4 5.0 4.4 10.9 18.4	46
807	Asphalt Protective Coatings Baghouse	Moved to Insignificant Activities List			
808	#7 FCCU Furnace	PM_{10} SO_2 VOC CO NO_x	1.0 2.4 1.0 6.0 8.0	4.4 8.3 4.4 20.3 27.1	45
809	#7 Catalyst Regenerator Stack	PM_{10} SO_2 VOC CO NO_x	7.50 26.5 183.3 116.0 59.2	32.9 58.3 805.2 101.9 259.9	57
810	#9 Hydrotreater Furnace/Reboiler	PM_{10} SO_2 VOC CO NO_x	1.0 3.1 1.0 7.5 12.7	4.4 10.3 4.4 25.3 43.0	46

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
811	#9 Reformer Furnace	PM_{10} SO_2 VOC CO NO_x	1.5 6.8 1.1 16.6 20.2	5.1 22.9 5.0 56.1 68.1	45
812	#9 Stabilizer Reboiler	PM_{10} SO_2 VOC CO NO_x	1.0 1.1 1.0 2.7 4.6	4.4 5.0 4.4 9.0 15.4	46
813	#10 Hydrotreater Furnace/Reboiler	PM_{10} SO_2 VOC CO NO_x	1.0 1.7 1.0 4.3 7.3	4.4 5.9 4.4 14.5 24.6	46
814	#11 Deasphalting Furnace	PM_{10} SO_2 VOC CO NO_x	1.0 1.4 1.0 3.4 5.8	4.4 5.0 4.4 11.6 19.7	46
816	#10 Boiler	PM_{10} SO_2 VOC CO NO_x	1.1 46.9 1.0 12.2 40.7	--- --- --- --- ---	63
817	#11 Boiler	PM_{10} SO_2 VOC CO NO_x	1.1 46.9 1.0 12.2 40.7	--- --- --- --- ---	63
818	#12 Boiler	PM_{10} SO_2 VOC CO NO_x	1.3 5.7 1.0 13.9 46.4	--- --- --- --- ---	63
819	#13 Boiler	PM_{10} SO_2 VOC CO NO_x	1.3 5.7 1.0 13.9 46.4	--- --- --- --- ---	63

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
820	#14 Boiler	PM_{10} SO_2 VOC CO NO_x	1.3 5.7 1.0 13.9 46.4	--- --- --- --- ---	63
816-820	#10-#14 Boilers – Annual Emissions Bubble	PM_{10} SO_2 VOC CO NO_x	--- --- --- --- ---	22.0 374.5 22.0 223.4 744.9	63
822 823	High and Low Pressure Flares	PM_{10} SO_2 VOC CO NO_x	99[1] 484[1] 842[1] 2,220[1] 612[1]	4.0 19.6 34.1 89.9 24.8	70
824	#16 Fume Incinerator	PM_{10} SO_2 VOC CO NO_x	2.0 23.1 4.1 123.3 2.0	8.8 101.5 18.0 541.5 8.8	73
825	#16 Asphalt Blowing Furnaces	PM_{10} SO_2 VOC CO NO_x	1.0 1.3 1.0 3.2 5.5	4.4 5.0 4.4 10.9 18.4	77
826	Acid Fume Scrubber	Moved to Insignificant Activities List			
827	Acid Fume Scrubber	Moved to Insignificant Activities List			
828	Asphalt Rack Steam Heater	PM_{10} SO_2 VOC CO NO_x	1.0 1.0 1.0 1.1 1.8	4.4 4.4 4.4 5.0 6.1	46
829	Steam Superheater Furnace	PM_{10} SO_2 VOC CO NO_x	1.0 1.0 1.0 1.1 1.8	4.4 4.4 4.4 5.0 6.1	45

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
830	Regenerant Furnace	PM_{10} SO_2 VOC CO NO_x	1.0 1.0 1.0 1.0 1.0	4.4 4.4 4.4 4.4 4.4	45
831	#9 Continuous Catalyst Regenerator	PM_{10} SO_2 VOC CO NO_x	2.0 2.0 2.0 2.6 2.0	8.8 8.8 8.8 11.4 8.8	80
832	47 Asphalt Tank Heaters	PM_{10} SO_2 VOC CO NO_x	1.0 4.3 1.0 10.6 12.9	4.4 14.7 4.4 35.9 43.6	81
833	South XVG Compressor	Source Removed from Service			
834	North KVG Compressor	CO NO_x	23.6 28.7	--- ---	86
835	South KVG Compressor	CO NO_x	23.6 28.7	--- ---	86
834 835	North KVG Compressor South KVG Compressor – Annual Emissions Bubble	CO NO_x	--- ---	21.2 25.8	86
836	8GTL Compressor	CO NO_x	18.2 21.1	34.2 39.6	86
837	North 8SVG Compressor	CO NO_x	2.9 1.9	12.8 8.5	86
838	South 10 SVG Compressor	CO NO_x	3.6 2.4	16.0 10.7	86
839	East JVG Compressor	CO NO_x	1.6 1.1	7.0 4.6	86
840	West JVG Compressor	CO NO_x	1.6 1.1	7.0 4.6	86
841	G398TA Air Compressor	CO NO_x	3.1 3.1	13.6 13.6	86

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
842	#12 Unit Distillate Hydrotreater	PM_{10} SO_2 VOC CO NO_x	1.0 2.2 1.0 5.4 5.3	4.4 7.4 4.4 18.1 17.8	45
843	#12 Unit Stripper Reboiler Furnace	PM_{10} SO_2 VOC CO NO_x	1.0 1.5 1.0 3.6 3.6	4.4 5.0 4.4 12.3 12.1	45
844	Sulfur Recovery Plant Incinerator	PM_{10} SO_2 VOC CO NO_x	12.0 19.1 1.5 8.1 6.0	52.7 53.4 6.6 35.3 26.3	45
845	Sludge Management Facility (Lime Silo Baghouse)	Moved to Insignificant Activities List			
846	Gasoline/Diesel Loading Rack	VOC	20.2	17.1	94
847	Heavy Oil Loading Racks	VOC	647.2	281.1	96
848	#7 FCCU Catalyst Hopper Vents	PM_{10}	25.0	1.8	98
849	Standby Diesel Crude Pump	PM_{10} SO_2 VOC CO NO_x	1.4 1.2 1.6 12.2 20.2	1.4 1.2 1.5 11.6 19.1	99
850	Asphalt Hot Oil Heater	PM_{10} SO_2 VOC CO NO_x	1.0 1.0 1.0 2.1 3.6	4.4 4.4 4.4 7.2 12.3	45
851	Wastewater Collection, Treatment, and Storage - old	VOC	900.0	3293.8	101

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
851a	Wastewater Collection, Treatment, and Storage - new	VOC	26.1	85.9	101
852	Vacuum Distillation Unit	Emissions routed to fuel gas recovery system with 2003 Tier 2 facility modifications			
853	Cooling Towers (Except SN-859)	PM_{10} VOC	90.8 24.7	356.0 108.7	105
854	Fugitive Equipment Leaks (Except SN-858)	VOC	970.5[2]	4159.4	106
856	Tank Plantwide Applicability Limit (Except SN-858)	VOC	13,651.3[1,2]	6908.6	114
857	Naptha Splitter Reboiler Heater	PM_{10} SO_2 VOC CO NO_x	1.4 2.1 1.0 5.2 2.2	5.3 7.9 3.8 19.3 8.2	140
858	Tier 2 Fugitives and Tanks Annual VOC Bubble	VOC	---	363.8	145
859	#8 Cooling Tower (replaces #1 Cooling Tower)	PM_{10} VOC	2.9 5.3	12.8 22.9	159
860	ULSD Hydrotreater Heater	PM_{10} SO_2 VOC CO NO_x	1.2 1.7 0.8 4.2 1.8	4.3 6.5 3.1 15.8 6.7	136

***HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.**

****Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.**

[1] This figure represents a lb/day limit rather than a lb/hr limit. For the purposes of summarizing plantwide lb/hr emissions in this table, the lb/day limit for these sources was divided by 24 hours of operation. This figure is for illustrative purposes only, and these sources are not limited on an hourly basis.

2 The Tier 2 fugitives and tanks are subject to and included in the short-term emission limits (hourly and/or daily) given for SN-854 and SN-856.

Section III: PERMIT HISTORY

Permit #82-A was issued on November 19, 1971. This permit was for the construction of a sodium hydrosulfide plant to replace the existing sulfur recovery plant.

Permit #167-A was issued September 28, 1973. This permit approved a catalytic cracking facility by combining two catalytic cracking units into one.

Permit #252-A was issued in July 1974. This permit allowed the replacement of three uncontrolled flares with one John Zink STF-SA-24S smokeless flare.

Permit #167-A (modification) was issued on September 27, 1974. This permit allowed the continued operation of the #3 fluid catalytic cracking unit beyond the period designated in the original permit in order to allow time to increase the capacity of the #7 unit.

Permit #337-A was issued on May 28, 1976. This permit allowed the installation of a stripper to remove H_2S from the refinery wastewater stream with the off gas being treated by the existing sodium hydrosulfide unit.

Permit #338-A was issued on May 28, 1976. This permit allowed the installation of a scrubber-incinerator-waste heat boiler to control emissions from the Asphalt Plant.

Permit #423-A was issued on August 18, 1977. In this permit, the facility proposed to install a baghouse to control asbestos emissions from the protective coatings plant.

Permit #438-A was issued on November 18, 1977. This permit allowed the installation of a pre-flash column reboiler heater in order for the facility to meet the EPA's requirement to reduce lead in gasoline.

Permit #454-A was issued on March 24, 1978. This permit allowed the facility to replace the existing truck loading dock with a new truck transport terminal for gasolines, distillates, and LPGs.

Permit #337-A (modification) was issued in March 1978. There had been a delay in the modification of the hydrosulfide unit. This permit allowed the facility to operate the stripper prior to the upgrade.

Permit #520-A was issued on September 29, 1978. This permit allowed the installation of new and revamped platforming and unifining furnaces in order for the facility to meet the second part of the lead phasedown as required by the EPA.

Permit #252-A (modification) was issued in June, 1979. This permit allowed the replacement of two 16 inch flares with one 24 inch high pressure flare.

Permit #252-A (modification) was issued on November 20, 1981. This permit allowed the facility to replace a gasoline blending storage tank that had been condemned by increasing the use of the remaining tanks and reactivating out of service tanks. In order to comply with NSPS requirements Tank #124 was fitted with a secondary seal to the external floating roof. Tanks #108 and #109 were fitted with internal floating roofs.

Permit #868-A was issued on January 4, 1988. This permit served to consolidate all of the active permits held by this facility into one permit. It also permitted an asphalt loading heater and Isomerization Project as part of the lead phasedown required by the EPA.

Permit #868-AR-1 was issued on December 26, 1990. This modification allowed the installation of a topping furnace on the #4 crude unit.

Permit #868-AR-2 was issued on June 7, 1991. This modification allowed the installation of a continuous catalyst regeneration unit of a platforming unit.

Permit #868-AR-3 was issued on January 5, 1993. This modification permitted the installation of a 100,000 barrel asphalt storage tank.

Permit #868-AR-4 was issued on May 27, 1993. This modification permitted the installation of a distillate hydrotreater with a capacity of 20,000 barrels per day. The purpose of this modification was to make on-road diesel quality fuel to meet the Clean Air Act Standards.

Permit #1596-A was issued on January 31, 1995. This permit allowed the installation of a Sulfur Recovery Plant to produce elemental sulfur.

Permit #868-AR-5 was issued on August 12, 1996. This modification dealt with the installation of a new 50,000 barrel storage tank to replace an existing tank, installation of a 25,000 BPD vacuum furnace to replace an existing furnace, installation of a Sulfur Recovery Plant to replace the existing Sodium Hydrosulfide Unit, and documented the emissions from on-site storage tanks, product loading racks, and process fugitive emissions. Permits #868-AR-4 and #1596-A were consolidated.

Permit #868-AR-6 was issued on February 6, 1998. This minor modification was to install a standby diesel fueled crude pump in order for Tank #63 (SN T-63 for this permit, SN-73 of the old permit) to meet the standards of 40 C.F.R. 63, Subpart CC- *National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*. The installation of the new pumping system allowed the tank to be taken out of crude oil storage service, and to be classified as a Group II storage vessel. This minor modification also allowed the facility to reduce VOC emissions from the tank, reduce crude oil inventories, and provide full emergency standby crude capacity in the event of a power failure.

Permit #868-AR-7 was issued on June 3, 1998. The purpose of this minor modification was to install an above ground storage tank (SN T-552) to replace an underground storage tank used to store gasoline for the company's motor fuel demands. The underground tank was owned by a company which provided fuel to Lion Oil.

Permit #868-AOP-R0 was issued on December 12, 2000 as the first operating permit for this facility as per the requirements of Regulation #26 and 40 C.F.R. § 70. In this permit, all of the tanks at the facility were bubbled under a PAL such that the facility has to comply with one VOC limit for the tank farm instead of a limit for each tank. Under this permit, the facility has permitted several sources that were previously unpermitted and increased several throughputs. The following minor modification and de minimis changes that were previously allowed were also included.

Minor modification submitted in September 1998: Permitted the Polymer Asphalt Let-Down Facility. The project consisted of installing a new gas fired hot oil system (SN-850), installation of two new tanks (SN's T-553 and T-554), modification of tanks (SN's T-24, T-384 through T-387)

De minimis change submitted May 1999: Allowed the facility to replace the existing Sour Water Stripper with a new 400 gal/min Sour Water Stripper to minimize odors at the refinery. A new 20,000 barrel storage tank for the storage of sour water was also installed as part of the project.

De minimis change submitted October 1999: Allowed the facility to upgrade the #4 Crude Unit with new and refurbished equipment. The improvements included the installation of seven pumps and approximately 236 hydrocarbon valves with associated flanging and the removal of two pumps, 198 hydrocarbon valves and associated flanging. The improvements to the #4 Crude Unit also allowed the facility to produce intermediates that were previously purchased from outside sources. Associated equipment that will be affected by the changes at the facility are the #4 Pre-flash Column Reboiler (SN-03), #4 Atmospheric Furnace (SN-04), the #4 Vacuum Furnace (SN-05), the #11 Deasphalting Furnace (SN-14), the Asphalt Loading Racks (SN's 205-208), Asphalt Storage Tanks #39, #40, #41, #55, #84, #219, and #368, and Diesel Storage Tanks #121 and #122.

De minimis change submitted February 1999: Allowed the facility to construct a new 5,000 barrel asphalt storage tank (SN T-78) to replace the existing 2,500 barrel storage tank.

In previous permitting actions, the tank numbers did not coincide with the source numbers. In order to eliminate confusion and correct the problem, the source numbers for the facility were changed in this permitting action. Source numbers 01-700 are reserved for tank purposes. Source numbers for the other sources start at 801. See Appendix L.

Permit No. 868-AOP-R1 was issued to Lion Oil Co. on Dec. 5, 2003. This permit was the first modification to Permit #868-AOP-R0. It was issued as a part of the Permit Appeal Resolution between the Department and the facility. The following changes were made in this permit:

- The method of demonstrating compliance with the emission limits for the facility's tanks was changed to allow the facility to track refinery crude feed rate instead of conducting a monthly emissions inventory.

- A plantwide applicability limit was established for various other air pollutants in lieu of individual source emission limits.

- The effective dates of several of the testing conditions and opacity readings were modified or changed.

- Several equipment capacities were corrected or modified.

- The Plantwide Conditions were modified to clarify the difference between refinery fuel gas and desulfurized refinery fuel gas and which sources were able to burn which fuels.

- Clarifications were made regarding applicability of various regulations. Various wording changes and typographical and error corrections were made throughout the Permit.

- Various alternate operating scenarios were added to allow the facility flexibility in its operations. The frequency of monitoring the Btu content of the desulfurized refinery fuel gas was clarified. The Cooling Towers section (SN-853) was changed to include two cooling towers that were omitted from the previous permit. The emissions were updated to include particulate emissions.

- The Insignificant Activities List was updated.

- The Permit was updated to reflect the installation of a flare gas recovery system to recover refinery gases. The Permit was updated to reflect the installation of two additional 5,000 barrel storage tanks (T-382 and T-383) and one additional loading rack (PMA #2 Loading Rack).

- Two new gas oil tanks, one 2,000 bbl storage tank (T-19), and one 8,200 bbl storage tank (T-59) were added to the permit. These tanks were constructed to replace two older existing tanks (T-20 and T-21) which were removed from service. These two new tanks were incorporated into the facility-wide PAL for VOC emissions from tanks.

- One additional gas fired tank heater was permitted for installation in asphalt storage tank No. 78 (T-78). This new heater is rated at 0.68 MMBtu/hr.

- The installation of a new, enclosed process wastewater treatment system was permitted with this modification. This new system allows for the segregation of process wastewater from refinery stormwater. The existing wastewater treatment system will be converted to stormwater-only usage once the new system is completed. This change should result in significant decreases in VOC emissions from the wastewater treatment systems at the refinery.

Section IV: Emission Unit Information

SN-801

#1 Crude Topping Furnace

Source Description

SN-801 was a 50 MMBtu/hr furnace used to heat crude oil to distillation level. The furnace is fueled with pipeline quality natural gas or desulfurized refinery fuel gas. It was installed in 1930. It was removed from service in 1986.

SN: 802

#1 Crude Vacuum Furnace

Source Description

SN-802 was a 12.0 MMBtu/hr boiler used to heat the heavy fraction of crude oil in order to separate it into asphalt and gas oil components. The boiler is fueled by pipeline quality natural gas or desulfurized refinery fuel gas. It was installed in 1960. It was removed from service in 1986.

SN's: 803, 804, 805, 806, 808, 810, 811, 812, 813, 814, 825, 828, 829, 830, 842, 843, 844, 850

#4 Pre-flash Column Reboiler, #4 Topping Furnace, #4 Vacuum Furnace, #6 Hydrotreater Furnace/Reboiler, #7 FCCU Furnace, #9 Hydrotreater Furnace/Reboiler, #9 Reformer Furnace, #9 Stabilizer Reboiler, #10 Hydrotreater Furnace/Reboiler, #11 Deasphalting Furnace, #16 Asphalt Blowing Furnaces, Asphalt Rack Steam Heater, Steam Superheater Furnace, Regenerant Furnace, #12 Unit Distillate Hydrotreater, #12 Unit Stripper Reboiler/Furnace, Sulfur Recovery Plant Catalytic Incinerator, PMA Hot Oil Heater

Source Description

All sources in this grouping are subject to 40 C.F.R., Part 60, Subpart J-*Standards of Performance for Petroleum Refineries*.

SN-803 is a 40 MMBtu/hr reboiler (nominal design) used to maintain the temperature in the pre-flash column in order to separate crude oil into gasoline and naphtha. The reboiler is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1979.

SN-804 is a 221.2 MMBtu/hr furnace (nominal design) used to heat the bottoms from the pre-flash column in order to separate them into naphtha, kerosene, diesel, and gas oil. The furnace is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1991. On May 22, 2001 and September 12, 2002, this source was tested for NOx emissions using EPA Reference Method 7E pursuant to §19.702 of Regulation 19, and 40 C.F.R., Part 52, Subpart E.

SN-805 is a 75 MM Btu/hr furnace (nominal design) used to heat the bottoms from the Atmospheric Column in order to separate them into gas oil and asphalt products in the Vacuum Column. The furnace is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1996. On May 17, 2000, this source was tested for NOx emissions EPA Reference Method 7E pursuant to 19.702 of Regulation 19, and 40 C.F.R., Part 52, Subpart E. The test results submitted to the Department demonstrated compliance.

SN-806 is a 30 MMBtu/hr furnace (nominal design) used to raise the temperature of light straight run (LSR) to reaction. It is fueled with pipeline quality natural gas or desulfurized refinery fuel gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the global settlement agreement between Lion Oil, ADEQ, and the US EPA.

SN-808 is a 56 MMBtu/hr furnace (nominal design) used to heat gas oil. It is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1979.

SN-810 is 70 MMBtu/hr furnace (nominal design) used to heat naphtha. It is fueled by pipeline quality natural gas or desulfurized refinery fuel gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the global settlement agreement between Lion Oil, ADEQ, and the US EPA.

SN-811 is a 155 MMBtu/hr furnace (nominal design) used to heat the #9 Unit Stripper bottoms. It is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1980.

SN-812 is a 25 MMBtu/hr furnace/reboiler (nominal design) used to heat platformate in order to remove low molecular weight gases. It is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the global settlement agreement between Lion Oil, ADEQ, and the US EPA.

SN-813 is a 40 MMBtu/hr furnace (nominal design) used to heat light cycle oil, diesel, kerosene, and gas oil. It is fueled by pipeline quality natural gas or desulfurized refinery fuel gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the global settlement agreement between Lion Oil, ADEQ, and the US EPA.

SN-814 is a 32 MMBtu/hr furnace (nominal design) used to heat asphalt from the bottom of the extraction tower. It is fueled by pipeline quality natural gas or desulfurized refinery fuel gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the global settlement agreement between Lion Oil, ADEQ, and the US EPA.

SN-828 is a 10 MMBtu/hr boiler (nominal design) used to heat asphalt products during truck loading. It is fueled by pipeline quality natural gas or desulfurized refinery fuel gas. It was installed in 1987.

SN-829 is a 10 MMBtu/hr furnace (nominal design) used to heat steam from the boilers to approximately 695EF. It is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1987. SN-829 is not an affected unit under Subpart Dc-*Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, because the unit was installed before 1989.

SN-830 is a 1.8 MMBtu/hr furnace (nominal design). It is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1987.

SN-842 is a 50.0 MMBtu/hr furnace (nominal design). It is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1993.

SN-843 is a 34.0 MMBtu furnace (nominal design). It is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1993. This unit was modified in 2003 to allow it to serve the #10 unit rather than the #12 unit. No emissions increases occurred at the source with this modification.

SN-844 is a 20.0 MMBtu/hr incinerator used to incinerate gases from the sulfur recovery plant. It is fueled by pipeline quality natural gas. It was installed in 1994. The incinerator is used to control emissions from the 3 stage sulfur recovery unit (SRU) which is also subject to Subpart J. The SRU is rated at 110 long tons per day (LTD).

SN-850 is a 20.0 MMBtu/hr heater (nominal design) used to supply heat to the hot oil system which maintains the elevated temperatures of stored asphalt products so that the material will flow without solidifying. This source was installed in 1998. It is fueled by pipeline quality natural gas and desulfurized refinery fuel gas. This source is subject to 40 C.F.R. 60, Subpart Dc-*Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units*.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for SN's 803-805, 808, 811, 829, 830, 842, 843, and 850 shall be demonstrated by compliance with Subpart J and the fuel and Btu limits for these sources. [Regulation No. 19 §19.501 *et seq.* effective February 15, 1999, and 40 CFR Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
803	#4 Pre-flash Column Reboiler		
	PM_{10}	1.0	4.4
	SO_2	1.7	5.9
	VOC	1.0	4.4
	CO	4.3	14.5
	NO_X	7.3	24.6
804	#4 Atmospheric Topping Furnace		
	PM_{10}	2.2	7.3
	SO_2	9.7	32.6
	VOC	1.6	5.2
	CO	23.7	80.1
	NO_X	12.9	43.7
805	#4 Vacuum Furnace		
	PM_{10}	1.0	4.4
	SO_2	3.3	11.1
	VOC	1.0	4.4
	CO	8.0	27.1
	NO_X	7.9	26.7

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Pollutant	lb/hr	tpy
806	#6 Hydrotreater Furnace/Reboiler		
	PM_{10}	1.0	4.4
	SO_2	1.3	5.0
	VOC	1.0	4.4
	CO	3.2	10.9
	NO_x	5.5	18.4
808	#7 FCCU Furnace		
	PM_{10}	1.0	4.4
	SO_2	2.4	8.3
	VOC	1.0	4.4
	CO	6.0	20.3
	NO_X	8.0	27.1
810	#9 Hydrotreater Furnace/Reboiler		
	PM_{10}	1.0	4.4
	SO_2	3.1	10.3
	VOC	1.0	4.4
	CO	7.5	25.3
	NO_x	12.7	43.0
811	#9 Reformer Furnace		
	PM_{10}	1.5	5.1
	SO_2	6.8	22.9
	VOC	1.1	5.0
	CO	16.6	56.1
	NO_X	20.2	68.1
812	#9 Stabilizer Reboiler		

SN	Pollutant	lb/hr	tpy
	PM_{10}	1.0	4.4
	SO_2	1.1	5.0
	VOC	1.0	4.4
	CO	2.7	9.0
	NO_x	4.6	15.4
813	#10 Hydrotreater Furnace/Reboiler		
	PM_{10}	1.0	4.4
	SO_2	1.7	5.9
	VOC	1.0	4.4
	CO	4.3	14.5
	NO_x	7.3	24.6
814	#11 Deasphalting Furnace		
	PM_{10}	1.0	4.4
	SO_2	1.4	5.0
	VOC	1.0	4.4
	CO	3.4	11.6
	NO_x	5.8	19.7
828	Asphalt Rack Steam Heater		
	PM_{10}	1.0	4.4
	SO_2	1.0	4.4
	VOC	1.0	4.4
	CO	1.1	5.0
	NO_x	1.8	6.1
829	Steam Superheater Furnace		
	PM_{10}	1.0	4.4

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Pollutant	lb/hr	tpy
	SO_2	1.0	4.4
	VOC	1.0	4.4
	CO	1.1	5.0
	NO_X	1.8	6.1
830	Regenerant Furnace		
	PM_{10}	1.0	4.4
	SO_2	1.0	4.4
	VOC	1.0	4.4
	CO	1.0	4.4
	NO_X	1.0	4.4
842	#12 Distillate Hydrotreater Furnace		
	PM_{10}	1.0	4.4
	SO_2	2.2	7.4
	VOC	1.0	4.4
	CO	5.4	18.1
	NO_X	5.3	17.8
843	#10 Stripper Reboiler Furnace		
	PM_{10}	1.0	4.4
	SO_2	1.5	5.0
	VOC	1.0	4.4
	CO	3.6	12.3
	NO_X	3.6	12.1
844	Sulfur Recovery Plant-Catalytic Incinerator		
	PM_{10}	12.0	52.7
	SO_2	19.1	53.4

SN	Pollutant	lb/hr	tpy
	VOC	1.5	6.6
	CO	8.1	35.3
	NO_X	6.0	26.3
850	Asphalt Hot Oil Heater		
	PM_{10}	1.0	4.4
	SO_2	1.0	4.4
	VOC	1.0	4.4
	CO	2.1	7.2
	NO_X	3.6	12.3

2. Any emissions to the atmosphere from any Claus sulfur recovery plant using an oxidation control system or a reduction control system followed by incineration shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Subpart J (see Appendix C). [§19.304 of Regulation 19 and 40 C.F.R. §60.104(a)(2)(i)]

SN	Pollutant	ppm by volume
844	Sulfur Recovery Plant - Catalytic Incinerator	
	SO_2 dry basis	250

3. The facility shall not exceed the annual Btu limits for the sources set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Specific Condition #4. [§ 19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

SN	Annual Limit (MMBtu/12 months)
803	351,360
804	1,943,021
805	658,800
806	263,520
808	491,904

810	614,880
811	1,361,520
812	219,600
813	351,360
814	281,088
829	87,840
830	15,811
842	439,200
843	298,656
850	175,680

4. Records of Btus shall be maintained on a twelve-month rolling basis for the sources listed in Specific Condition #3. These records shall be updated monthly. These records shall include the fuel combusted (natural gas or desulfurized refinery fuel gas) and heat duty (amount of gas x heating value). The heating value shall be determined by Plantwide Condition #10. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

5. The facility shall not exceed 5% opacity from the sources in this section burning pipeline quality natural gas or desulfurized refinery fuel gas. Compliance with this limit shall be demonstrated by burning only pipeline quality natural gas or refinery fuel gas. If the H_2S concentration of the refinery fuel gas exceeds 1500 ppmvd, then the facility shall comply with Plantwide Condition #12. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

6. The facility shall use only pipeline quality natural gas as fuel for SN-844. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

7. The facility shall use only pipeline quality natural gas or desulfurized refinery fuel gas (as defined by Plantwide Condition #8(a)) as fuel for SN's 803-806, 808, 810-814, 828-830, 842, 843, and 850. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

8. Under the terms of 40 C.F.R. Part 60 Subpart Dc-*Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units,* SN-850 is an affected facility (see Appendices D and E). [§19.304 of Regulation 19, and 40 C.F.R. §60.40c]

   In lieu of § 60.48c(g), in which the owner or operator of each facility shall record and maintain records of the amounts of each fuel combusted during each day, the facility through a letter of approval from John R. Hepola, Chief, Air/Toxics and Inspection Coordination Branch, EPA to Thomas Rheaume of the Arkansas Department of Environmental Quality dated February 9, 1999, may record and maintain records of the amounts of each fuel combusted during each month.

9. The following sources are affected facilities under the provisions of 40 C.F.R. 60, Subpart J-*Standards of Performance for Petroleum Refineries*: SN's 803, 804, 805, 806, 808, 810, 811, 812, 813, 814, 828, 829, 830, 842, 843, 844 and 850. They are defined in the subpart as fuel gas combustion devices. These sources are all subject to the Subpart J requirements, which are summarized in Specific Conditions #2 and #7, and below (for the full regulation, see Appendix C): [§19.304 of Regulation 19 and 40 CFR §60.100]

   a. Pursuant to § 60.105(a), the facility shall install, calibrate, maintain and operate continuous monitoring systems in accordance with the provisions of § 60.105 outlined below.

   b. Pursuant to § 60.105(a)(3), for SN's 803, 804, 805, 808, 811, 829, 830, 842, and 843 the facility shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (except where an H_2S monitor is installed under paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess air.

      i. The span values for this monitor are 50 ppm SO_2 and 10 percent oxygen (O_2).

      ii. The SO_2 monitoring level equivalent to the H_2S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

      iii. The performance evaluations for this monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 and 3 (or other approved method) shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

      iv. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

   c. Pursuant to § 60.105(a)(4), the facility may, in place of the SO_2 monitor in paragraph (a)(3), install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device.

      i. The span value for this instrument is 425 mg/dscm H_2S.

ii. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

iii. The performance evaluations for this H_2S monitor under § 60.13(c) shall use Performance Specification 7. Method 11 (or other approved method) shall be used for conducting the relative accuracy evaluations.

d. Pursuant to § 60.105(a)(5), for Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to § 60.104(a)(2)(i) (SN-844), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

i. The span values for this monitor are 500 ppm SO_2 and 10 percent O_2.

ii. The performance evaluations for this SO_2 monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 and 3 (or other approved method) shall be used for conducting the relative accuracy evaluations.

e. Pursuant to § 60.105(e), for purposes of reports under § 60.7(c), periods of excess emissions for sulfur dioxide from fuel gas combustion shall be determined and reported as required by § 60.105(e)(3).

f. Pursuant to § 60.105(e), for purposes of reports under § 60.7(c), periods of excess emissions for sulfur dioxide from the Claus sulfur recovery plant shall be determined and reported as required by § 60.105(e)(4).

g. Pursuant to § 60.106(a), in conducting the performance tests required in § 60.8, the facility shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

h. Pursuant to § 60.106(e), the owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11 (or other approved method) shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

i. Pursuant to § 60.106(f), the facility shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in § 60.104(a)(2) by § 60.106(f)(1), (2), and (3).

j. Pursuant to § 60.106(f)(1), Method 6 (or other approved method) shall be used to determine the SO_2 concentration. The concentration in mg/dscm (lb/dscf) obtained by Method 6 (or other approved method) is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m^2 (54 ft^2) or at a point no closer to the walls than 1.00 m (39 in.) if the cross-sectional area is 5.00 m^2 or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases. The sampling point for Method 4 (or other approved method) shall be adjacent to the sampling point for Method 6 (or other approved method). The sampling time for each sample shall be equal to the time it takes for two Method 6 (or other approved method) samples. The moisture content from this sample shall be used to correct the corresponding Method 6 (or other approved method) samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 (or other approved method) shall be used following the procedures of paragraph (f)(2) of this section.

k. Pursuant to § 60.106(f)(2), Method 15 (or other approved method) shall be used to determine the reduced sulfur and H_2S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 (or other approved method) in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

l. Pursuant to § 60.106(f)(3), the oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 (or other approved method). The samples shall be taken simultaneously with the SO_2, reduced sulfur and H_2S, or moisture samples. The SO_2, reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(3) of this section.

10. The permittee shall operate the #4 Atmospheric Furnace (SN-804) such that NOx emissions to the atmosphere do not exceed 0.045 lb/mmBtu based on a 3-hour average. [§19.501 of Regulation 19, 40 CFR Part 52 Subpart E, and Paragraph 16(D) of the consent agreement between Lion Oil, the US EPA, and ADEQ]

11. No later than December 31, 2004, the permittee shall install and operate a CEM system in the #4 Atmospheric Furnace exhaust stack for the purposes of monitoring NOx emissions. The data from this monitored shall be recorded and compiled in order to demonstrate compliance with the lb/mmBtu NO_x limit contained in Specific Condition #10. [[§19.501 of Regulation 19, 40 CFR Part 52 Subpart E, and Paragraph 16(D) of the consent agreement between Lion Oil, the US EPA, and ADEQ]

12. The fuel combusted in the #4 atmospheric furnace shall be sampled at least three times per calendar week in order to determine the higher heating value (HHV) and F-factor for the purposes of calculating the lb/mmBtu NO_x emissions using US EPA Method 19 as required by Specific Conditions #10 and #13. Records of the results of this testing shall be maintained on-site, and shall be made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E]

13. All CEMs in use at the facility shall be operated in accordance with the Department's CEM Conditions (see Appendix K). The facility shall submit CEM data in accordance with the Department's standards. CEM data shall be submitted in ppm for the refinery gas H_2S analyzers for SN's 803-806, 808, 810-814, 828-830, 842, 843, and 850. CEM data shall be submitted in ppm, lb/hr, and tpy for SN-844. Data for SN-804 shall be submitted in lb NO_x/mmBtu. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-809

#7 FCCU Catalyst Regenerator Stack

Source Description

SN-809 is the exhaust stack from the catalyst regenerator. Hot flue gas leaving the regenerator passes through three sets of cyclones to remove catalyst fines and then is used to produce steam in the waste heat boiler before exiting the stack. This source was installed in 1973.

The #7 FCCU was modified in 2004 to install a wet gas scrubber for the control of PM_{10} and SO_2 emissions. Simultaneous with the installation of the scrubber, the facility also accepted a limit of 500 ppmdv (1-hour average) and 100 ppmdv (365-day rolling average) as required by the consent decree agreement reached between Lion Oil, the US EPA, and ADEQ. CEMs were installed to monitor the stack concentrations of SO_2, CO, and O_2.

Regulations

On December 31, 2004, the Fluid Catalytic Cracking Unit (FCCU) will become subject to 40 C.F.R., Part 60, Subpart J-*Standards of Performance for Petroleum Refineries*.

CAM (40 CFR Part 64) parametric monitoring will not be required for this unit at this time due to its status as an existing unit, as well as the presence of CEM systems in the FCCU exhaust stack.

Specific Conditions

14. The permittee shall not exceed the emission rates set forth in the following tables. The permittee shall comply with the emission limits contained in Table 23.1 below until December 31, 2004. On and after December 31, 2004, the facility shall be subject to, and shall comply with the limits contained in Table 23.2. Under no circumstances shall the limits of Table 23.1 apply on or after December 31, 2004. Compliance with these limits shall be demonstrated by compliance with the throughput limits and monitoring requirements for this source. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 23.1 – Emission Limitations prior to December 31, 2004			
SN	Pollutant	lb/hr	Tpy
809	#7 Catalyst Regenerator Stack		
	PM_{10}	75.0	329.4
	SO_2	442.9	1945.2

	VOC	183.3	805.2
	CO	2405.5	10565.0
	NO_X	59.2	259.9

Table 23.2 – Emission Limitations on and After December 31, 2004			
SN	Pollutant	lb/hr	Tpy
809	#7 Catalyst Regenerator Stack		
	PM_{10}	7.5	32.9
	SO_2	26.5	58.3
	VOC	183.3	805.2
	CO	116.0	101.9
	NO_X	59.2	259.9

15. The total fresh feed rate of charging stock to this source shall be limited to 7.32 million bbls per consecutive twelve month period. This limit will not apply after December 31, 2004. [§19.501 of Regulation 19 *et seq.*, and 40 CFR, Part 52]

16. Records of the total fresh feed rate of charging stock to this source shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #6. These records will no longer be required after December 31, 2004. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

17. The facility shall not exceed 20% opacity from this source. Compliance with this condition will be demonstrated by compliance with 40 CFR Part 60 Subpart J, the operation of the wet gas scrubber (WGS), and compliance with any alternative monitoring provision approved for this source by the US EPA. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

18. The permittee shall install and operate a wet gas scrubber (WGS) system on the #7 FCCU unit. On and after December 31, 2004, this WGS system shall achieve the following outlet emissions limitations. Compliance with this condition shall be demonstrated by the installation and operation of the WGS system, by compliance with Specific Conditions #19, #21, #22, and the provisions of 40 CFR Part 60 Subpart J. [§19.501 et seq, 40 CFR Part 52

Subpart E, and Paragraphs 12 and 13 of the global settlement agreement between Lion Oil, ADEQ, and the US EPA]

a. For SO_2:

i. No more than 25 ppmvd based on a 365-day rolling average, corrected to 0% oxygen.

ii. No more than 50 ppmvd based on a 7-day rolling average, corrected to 0% oxygen

b. For PM:

i. No more than 0.5 pounds of particulate matter (PM) per 1000 pounds of coke burned, on a 3-hour average basis.

19. The permittee shall perform stack testing during the next turn down event after the installation of the WGS in order to examine the capability of the WGS to meet the limit of 0.5 lb PM per 1000 lb coke (3-hr average). The permittee shall perform this stack testing under two scenarios, at 90% (max) capacity and at a low throughput rate. Based on the low throughput testing, this emission limitation may be modified during turn down events. Any such modification in the emission limit must first be approved by the Department in writing. This testing shall be performed according to EPA Reference Method 5B. This testing shall be performed no later than December 31, 2004. The permittee shall submit a report of the results of this testing to the Department no later than 90 days after the scheduled turn down event. [§19.702 of Regulation 19, 40 CFR Part 52 Subpart E, and Paragraph 13 of the consent decree agreement]

20. On and after December 31, 2004, the permittee shall not exceed the following stack gas concentrations for CO. Compliance with this condition shall be demonstrated by compliance with Specific Conditions #21, #22, and the provisions of 40 CFR Part 60 Subpart J. [§19.501 et seq, 40 CFR Part 52 Subpart E, and Paragraph 14(B) of the consent decree agreement]

a. 500 ppmvd corrected to 0% O_2, over a 1-hour averaging period.

b. 100 ppmvd corrected to 0% O_2 as a rolling 365-day average.

21. On and after December 31, 2004, the permittee shall maintain records of the SO_2, CO, and O_2 CEM data which demonstrate compliance with the emission limitations of Specific Conditions # 18 and #20. These records shall be maintained on-site, shall be made available to Department personnel upon request, and shall be submitted in accordance with the Department's CEMS standards (Appendix K). [§19.705 and 40 CFR Part 52 Subpart E]

22. On December 31, 2004, the FCCU will become an affected facility under the terms of 40 CFR Part 60 Subpart J – *Standards of Performance for Petroleum Refineries*. The requirements of this subpart as they apply to this source are summarized below. For the

purposes of reporting excursions or exceedances from the provisions of this subpart, the first report shall be due to the Department no later than April 30, 2005. [§19.304 of Regulation 19 and 40 CFR §60.100]

a. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain particulate matter (PM) in excess of 2.0 lb/ton of coke burn-off in the catalyst regenerator. [§60.102(a)(1)]

b. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which exhibit an opacity greater than 30% except for one six-minute average opacity reading in any one hour period. [§60.102(a)(2)]

c. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain carbon monoxide (CO) in excess of 500 ppmvd. [§60.103(a)]

d. The permittee shall operate an add-on control device (WGS) to reduce SO_2 emissions to the atmosphere from the #7 FCCU Catalyst Regenerator Stack (SN-809) to a level below 50 ppmvd. Compliance with this limit shall be determined daily on a rolling 7-day basis. A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days. [§§60.104(b)(1), 60.104(c), and 60.104(d)]

e. Continuous emission monitoring (CEM) systems shall be installed, calibrated, maintained, and operated in the #7 FCCU Catalyst Regenerator Stack (SN-809) by the permittee as follows:

   i. The permittee has applied for approval from the US EPA for an alternative monitoring plan to demonstrate compliance with particulate matter control pursuant to Subpart J. If the administrator grants approval of this request, then the facility shall operate in compliance with the plan at all times, and a copy of the approval letter, as well as the alternative monitoring plan, shall be maintained along with this permit at the facility. If approval of the alternative monitoring plan is not granted, then the facility shall install a continuous opacity monitoring (COM) system in accordance with the requirements of Subpart J. [§60.105(a)(1)]

   ii. A CEM system shall be installed for the continuous monitoring and recording of the concentration by volume (dry basis) of CO emissions to the atmosphere from the #7 FCCU Catalyst Regenerator Stack. The span value for this system shall be 1,000 ppm CO. [§60.105(a)(2)]

   iii. A CEM system shall be installed for the continuous monitoring and recording of the concentration by volume (dry basis) of SO_2 emissions to the atmosphere from the #7 FCCU Catalyst Regenerator Stack (SN-809). The span value for this system shall be 100 ppm SO_2. [§60.105(a)(9)]

iv. A CEM system shall be installed for the continuous monitoring and recording of the concentration by volume of oxygen (O_2) in the #7 FCCU Catalyst Regenerator Stack (SN-809). The span value for this system shall be 10 percent. [§60.105(a)(10)]

v. The SO_2 and O_2 CEM systems operated in the #7 FCCU Catalyst Regenerator Stack (SN-809) shall be operated and data recorded during all periods of operation of the FCCU including periods of startup, shutdown, or malfunction, except for CEM system breakdowns, repairs, calibration checks, and zero and span adjustments [§60.105(a)(11)]

vi. The permittee shall use the following procedures to evaluate the SO_2 and O_2 CEM systems operated in the #7 FCCU Catalyst Regenerator Stack (SN-809).

1. Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the §60.13(e) performance evaluation. [§60.105(a)(12)(i)]

2. Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drifts. [§60.105(a)(12)(ii)]

vii. For the purposes of complying with the 50 ppmvd SO_2 emission limit, when emission data are not obtained because of CEM system breakdowns, repairs, calibration checks, and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in a least 22 out of 30 rolling successive calendar days. [§60.105(a)(13)]

1. The test methods as described in §60.106(k);

2. A spare CEM system; or

3. Other monitoring systems as approved by the Administrator.

viii. The average coke burn-off rate shall (tons per hour) shall be recorded daily for the #7 FCCU Catalyst Regenerator. [§60.105(c)]

ix. For the purpose of reports under §60.7(c), periods of excess emissions that shall be determined and reported are defined as follows: [60.105(e)]

1. For Opacity: All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the COM system exceeds 30 percent.

2. For CO: All 1-hour periods during which the average CO concentration measured by the CEM system exceeds 500 ppmvd corrected to zero percent O_2.

f. In conducting the performance tests required in 40 CFR §60.8, the permittee shall use as reference methods the test methods in Appendix A of Part 60, and the methods and procedures specified in §§60.106(b), 60.106(g), 60.106(h), and 60.106(k). The permittee may choose to perform this initial testing concurrently with the certification of the CEM systems for this source. If the initial performance tests are to be performed concurrently with the CEM certifications, this shall be noted on the testing protocol submitted to the Department prior to the test date. [§60.106(a)]

g. The permittee shall record and maintain the following information pertaining to the SO_2 monitoring requirements for the #7 FCCU Catalyst Regenerator Stack (SN-809). [§60.107(b)]

   i. All data and calibrations from the SO_2 CEM system, including the results of the daily drift tests and quarterly accuracy assessments required under Appendix F, Procedure 1;

   ii. Measurements obtained by supplemental sampling for meeting minimum data requirements; and

   iii. The written procedures for the quality control program required by Appendix F, Procedure 1.

h. The permittee shall submit a report on the SO_2 CEM system which contains all of the information required by §§60.107(c) and (d). This report shall be submitted to the Department in accordance with the Department CEM Standards (Appendix K). [§§60.107(c), (d), and (e)]

i. The owner or operator of the facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report. [§60.107(f)]

23. All CEMS shall be operated in accordance with the Department's CEM Conditions. The facility shall submit CEM data in accordance with the Department's standards. A copy of these standards has been attached as Appendix K. [§19.703 of Regulation 19, 40 CFR Part 52 Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311

SN-816 through SN-820

#10 Boiler, #11 Boiler, #12 Boiler, #13 Boiler, #14 Boiler

Source Description

SN-816 is a 114 MMBtu/hr low pressure boiler (nominal design). The boiler is fueled by pipeline quality natural gas or refinery fuel gas. It was installed in 1945.

SN-817 is a 114 MMBtu/hr low pressure boiler (nominal design). The boiler is fueled by pipeline quality natural gas or refinery fuel gas. It was installed in 1945.

SN-818 is a 130 MMBtu/hr high pressure boiler (nominal design). The boiler is fueled by pipeline quality natural gas or refinery fuel gas. It was installed in 1952.

SN-819 is a 130 MMBtu/hr high pressure boiler (nominal design). The boiler is fueled by pipeline quality natural gas or refinery fuel gas. It was installed in 1952.

SN-820 is a 130 MMBtu/hr high pressure boiler (nominal design). The boiler is fueled by pipeline quality natural gas or refinery fuel gas. It was installed in 1958.

Regulations

SN's 816-820 are not subject to 40 C.F.R. 60, Subpart Db-*Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units* or Subpart Dc-*Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* because they were installed prior to the effective date of the Subparts.

As a result of the global settlement agreement reached between Lion Oil, ADEQ, and the US EPA, SN's 818-820 are currently subject to 40 CFR Part 60 Subpart J. SN's 816 and 817 will become subject to 40 CFR Part 60 Subpart J on January 31, 2006. SN-818-820 are scheduled to be removed from service prior to this date, and replaced with new boilers which will also be subject to Subpart J.

Specific Conditions

24. The listed sources shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the Btu and fuel limits for these sources. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
816	#10 Boiler		
	PM_{10}	1.1	---

SN	Pollutant	lb/hr	tpy
	SO_2	46.9*	---
	VOC	1.0	---
	CO	12.2	---
	NO_X	40.7	---
817	#11 Boiler		
	PM_{10}	1.1	---
	SO_2	46.9*	---
	VOC	1.0	---
	CO	12.2	---
	NO_X	40.7	---
818	#12 Boiler		
	PM_{10}	1.3	---
	SO_2	5.7	---
	VOC	1.0	---
	CO	13.9	---
	NO_X	46.4	---
819	#13 Boiler		
	PM_{10}	1.3	---
	SO_2	5.7	---
	VOC	1.0	---
	CO	13.9	---
	NO_X	46.4	---
820	#14 Boiler		

SN	Pollutant	lb/hr	tpy
	PM_{10}	1.3	---
	SO_2	5.7	---
	VOC	1.0	---
	CO	13.9	---
	NO_X	46.4	---
816-820	#10-#14 Boilers Annual Emissions		
	PM_{10}	---	22.0
	SO_2	---	374.5
	VOC	---	22.0
	CO	---	223.4
	NO_X	---	744.9

***Based on the lower range of the gross heating value of the fuel (800 Btu/scf).**

25. These sources shall not exceed the annual Btu limit in the following table. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

SN	Combined Annual Limit (MMBtu/12 months)
816-820	5,428,512

26. Records of Btus shall be maintained on a twelve-month rolling basis, updated monthly. These records shall include the fuel combusted (natural gas, desulfurized refinery fuel gas or refinery fuel gas) and heat duty (amount of gas x heating value). The heating value shall be determined by Plantwide Condition #10. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

27. The fuel gas fired at SN-816 and SN-817 shall contain no more than 0.15 mole percent H_2S. The facility will demonstrate compliance with this limit as outlined in Specific Condition

#31. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

28. The facility shall not exceed 5% opacity from these sources. Compliance with this condition shall be demonstrated by burning only pipeline quality natural gas, refinery fuel gas, or desulfurized refinery fuel gas. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

29. The facility shall use only pipeline quality natural gas, refinery fuel gas, or desulfurized refinery fuel gas as fuel for SN-816 and SN-817. For those sources subject to NSPS Subpart J (SN-818 through SN-820) only natural gas or desulfurized refinery fuel gas (as defined by Plantwide Condition #8(a)) may be used. In the event of pipeline quality natural gas curtailment, emergency, or upset conditions as set forth in Chapter 6 of Regulation 19, the boilers may be fired with fuel oil if fuel gas is unavailable. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

30. In the event that fuel oil is used at this source, the facility shall maintain records of fuel oil usage including the amount of fuel oil used and the sulfur content of the fuel oil. Records shall be maintained on site and submitted in accordance with Chapter 6 of Regulation 19. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

31. The refinery fuel gas shall be sampled for H_2S concentration no less than twice per month only when the facility is utilizing refinery fuel gas. Otherwise, the facility's CEM system will be used to demonstrate compliance with the H_2S concentration in Specific Condition #27. Records shall be maintained on site and submitted to the Department in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

32. The following sources are affected facilities under the provisions of 40 C.F.R. 60, Subpart J-*Standards of Performance for Petroleum Refineries*: SN's 818, 819, and 820. They are defined in the subpart as fuel gas combustion devices. These sources are all subject to the Subpart J requirements, which are summarized in Specific Condition #29 and below (for the full regulation, see Appendix C): [§19.304 of Regulation 19 and 40 CFR §60.100]

    a. Pursuant to § 60.105(a), the facility shall install, calibrate, maintain and operate continuous monitoring systems in accordance with the provisions of § 60.105 outlined below.

    b. Pursuant to § 60.105(a)(3), for SN's 818, 819, and 820 the facility shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (except where an H_2S monitor is installed under paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess air.

        i. The span values for this monitor are 50 ppm SO_2 and 10 percent oxygen (O_2).

ii. The SO_2 monitoring level equivalent to the H_2S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

iii. The performance evaluations for this monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 and 3 (or other approved method) shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

iv. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

c. Pursuant to § 60.105(a)(4), the facility may, in place of the SO_2 monitor in paragraph (a)(3), install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device.

i. The span value for this instrument is 425 mg/dscm H_2S.

ii. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

iii. The performance evaluations for this H_2S monitor under § 60.13(c) shall use Performance Specification 7. Method 11 (or other approved method) shall be used for conducting the relative accuracy evaluations.

d. Pursuant to § 60.105(e), for purposes of reports under § 60.7(c), periods of excess emissions for sulfur dioxide from fuel gas combustion shall be determined and reported as required by § 60.105(e)(3).

e. Pursuant to § 60.106(a), in conducting the performance tests required in § 60.8, the facility shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

f. Pursuant to § 60.106(e), the owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11 (or other approved method) shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

g. Pursuant to § 60.106(f), the facility shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in § 60.104(a)(2) by § 60.106(f)(1), (2), and (3).

h. Pursuant to § 60.106(f)(1), Method 6 (or other approved method) shall be used to determine the SO_2 concentration. The concentration in mg/dscm (lb/dscf) obtained by Method 6 (or other approved method) is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m^2 (54 ft^2) or at a point no closer to the walls than 1.00 m (39 in.) if the cross-sectional area is 5.00 m^2 or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases. The sampling point for Method 4 (or other approved method) shall be adjacent to the sampling point for Method 6 (or other approved method). The sampling time for each sample shall be equal to the time it takes for two Method 6 (or other approved method) samples. The moisture content from this sample shall be used to correct the corresponding Method 6 (or other approved method) samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 (or other approved method) shall be used following the procedures of paragraph (f)(2) of this section.

i. Pursuant to § 60.106(f)(2), Method 15 (or other approved method) shall be used to determine the reduced sulfur and H_2S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 (or other approved method) in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

j. Pursuant to § 60.106(f)(3), the oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 (or other approved method). The samples shall be taken simultaneously with the SO_2, reduced sulfur and H_2S, or moisture samples. The SO_2, reduced sulfur, and

H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(3) of this section.

SN-822 and SN-823

High and Low Pressure Flares

Source Description

SN-822 and SN-823 are steam assisted flares used to provide for the safe disposal of hydrocarbon- vapors discharged from refinery process units from upset conditions, startups, shutdowns and malfunctions. The gases that will be routinely combusted in the flares are pilot gas, purge gas, and desulfurized refinery fuel gas from the fuel gas system.

SN-822 maintains a pilot light designed at 1.5 MM Btu/hr and is known as the high pressure flare. It was installed in 1979.

SN-823 maintains a pilot light designed at 1.5 MM Btu/hr and is known as the low pressure flare. It was installed in 1974.

A Flare Gas Recovery System (FGRS) has been installed at the facility. The purpose of the FGRS is to recover refinery gases. The FGRS compresses the flare gases and allows them to be processed either in the fuel gas system or through the gas plant. When the fuel gas produced exceeds refinery demand, excess gas meeting the requirements of 40 C.F.R., Part 60, Subpart J, may be routed to the flares. The FGRS is not a source of emissions.

Regulations

The flares are both subject to 40 C.F.R., Part 60, Subpart J-*Standards of Performance for Petroleum Refineries*.

Specific Conditions

33. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by operation of the flare gas recovery system and by compliance with the fuel and flow rate limits of this section. [§ 19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/day	tpy
822, 823	Both Flares		
	PM_{10}	99	4.0
	SO_2	484	19.6
	VOC	842	34.1

SN	Pollutant	lb/day	tpy
	CO	2,220	89.9
	NO_X	612	24.8

34. The flare gas recovery system shall be in operation at all times. [§19.705 of Regulation 19, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

35. The flares shall be operated as required in § 60.18. These requirements are summarized below. [§19.304 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 60.18]

    a. The flares shall be operated with a flame present at all times as required by § 60.18(c)(2).

    b. The facility shall monitor the flares to ensure they are operated and maintained in conformance with their designs in accordance with § 60.18(d).

    c. The flares shall be operated at all times when emissions may be vented to them as required by § 60.18(e).

36. The flares shall be operated with no visible emissions, except for periods not to exceed a total of five minutes during any consecutive two hour period, when the flares may have emissions not to exceed 60% opacity. [§19.304 and § 19.503 of Regulation 19 and 40 C.F.R. § 60.18(c)(1)]

37. The high and low pressure flares (SN-822 and SN-823) are affected facilities under the terms of 40 CFR Part 60 Subpart J – *Standards of Performance for Petroleum Refineries*. These sources are subject to the Subpart J requirements, which are summarized below (for the full regulation, see Appendix C). [§ 19.304 of Regulation 19 and 40 CFR §60.100]

    l. In accordance with § 60.104(a)(1), the permittee shall not burn any fuel gas that exceeds the concentration set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Subpart J.

SN	Pollutant	mg/dscm	gr/dscf
822, 823	Fuel Gas Combustion Devices		
	H_2S	230	0.10

The combustion in a flare of process upset gases or fuel gas that is released to the flares as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

b. The facility shall monitor emissions and operations in accordance with § 60.105(a)(3) or (a)(4).

c. The test methods and procedures shall be conducted as required in § 60.106(a), (e), and (f).

d. The reporting and recordkeeping requirements shall be kept as required in § 60.107(d), (e), and (f).

38. The total flow of pilot gas, purge gas and excess desulfurized fuel gas or refining fuel gas to the flares shall be limited to 6 MM scf/day and a total limit of 486 MM scf per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

39. Records for the rolling annual flow rate in Specific Condition #38 shall be maintained on a twelve-month rolling basis, updated monthly. Records shall be maintained to demonstrate compliance with the daily limit in Specific Condition #38. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

40. The facility shall burn only pipeline quality natural gas or desulfurized refinery fuel gas (as defined by Plantwide Condition #8(a)) as fuel for this source. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

41. The flares and flare gas recovery system shall be operated as described in this section at all times. In the event of an upset, emergency condition, startup, shutdown, or malfunction, the Department will forego enforcement action if the permittee complies with the requirements of Regulation 19, Chapter 6, Upset and Emergency Conditions, and 40 C.F.R. § 60.11 for federally regulated air pollutant emissions and Regulation 18, Chapter 11, § 18.1101, Upsets, for other air emissions. Permittee shall submit the reports as referenced in §§ 19.601(C) and 18.1101(B) within 30 days of the upset, emergency condition, startup, shutdown and malfunction. [§19.601 and § 19.602 of Regulation 19, and 40 C.F.R., Part 52, Subpart E, and 40 C.F.R., Part 60]

SN-824

Fume Incinerator

Source Description

SN-824 is a 15 MMBtu/hr incinerator (nominal design) used to incinerate hydrocarbon vapors emitted from the asphalt blowing process subsequent to vapor scrubbing. It is fueled by purchased pipeline quality natural gas and desulfurized refinery fuel gas. It was installed in 1977.

On May 23 – 24, 2001, this source was tested for SO_2 emissions using EPA Reference Method 6C pursuant to 19.702 of Regulation 19, and 40 C.F.R., Part 52, Subpart E.

Regulations

Pursuant to 40 C.F.R. 60, Subpart J-*Standards of Performance for Petroleum Refineries,* the Asphalt Blowing Incinerator is an affected facility.

Specific Conditions

42. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the operational limits for this source. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
824	Fume Incinerator		
	PM_{10}	2.0	8.8
	SO_2	23.1	101.5
	VOC	4.1	18.0
	CO	123.3	541.5
	NO_X	2.0	8.8

43. The combustion temperature of the incinerator shall be maintained at or above 1185EF during blowing operations only. The facility shall install, calibrate, maintain, and operate a temperature monitoring device to demonstrate that the combustion temperature of the incinerator has been maintained while it is operating. During periods of maintenance on or failure of the monitoring equipment, the facility shall manually measure and record the

combustion temperature in the incinerator at least once per hour. Any measurement falling below the prescribed temperature shall be reported in accordance with § 19.601 of Regulation 19. §19.703 of Regulation 19, 40 C.F.R., Part 52, Subpart E, and A.C.A. § 8- 4-203 as referenced by § 8-4-304 and § 8-4-311]

44. Records for the operating combustion temperature of the incinerator during blowing operations shall be maintained on a continuous basis. The facility shall also maintain records indicating when the facility is conducting blowing operations. Such records shall be maintained on site and made available to Department personnel upon request. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

45. The facility shall use only pipeline quality natural gas or desulfurized refinery fuel gas (as defined in Plantwide Condition #8(a)) as fuel for this source. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]

46. The facility shall not exceed 5% opacity from the sources in this section burning pipeline quality natural gas or desulfurized refinery fuel gas. Compliance with this limit shall be demonstrated by burning only pipeline quality natural gas or refinery fuel gas. If the H_2S concentration of the refinery fuel gas exceeds 1000 mg/dscm (0.435 gr/dscf), then the facility shall comply with Plantwide Condition #12. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

47. The Fume Incinerator (SN-824) is an affected facility under the provisions of 40 CFR Part 60 Subpart J – *Standards of Performance for Petroleum Refineries*. This source is subject to the Subpart J requirements, which are summarized below (for the full regulation see Appendix C). [§19.304 of Regulation 19 and 40 CFR §60.100]

    a. In accordance with § 60.104(a)(1), the permittee shall not burn any fuel gas that exceeds the concentration set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Subpart J.

SN	Pollutant	mg/dscm	gr/dscf
824	Fuel Gas Combustion Devices		
	H_2S	230	0.10

    The combustion in a flare of process upset gases or fuel gas that is released to the flares as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

    b. The facility shall monitor emissions and operations in accordance with § 60.105(a)(3) or (a)(4).

    c. The test methods and procedures shall be conducted as required in § 60.106(a), (e), and (f).

d. The reporting and recordkeeping requirements shall be kept as required in § 60.107(d), (e), and (f).

SN-824A

#16 Asphalt Blowing Operations (Fume Incinerator) Alternate Operating Scenario

Specific Conditions

48. As an alternate operating scenario, for safety reasons the facility may vent emissions from the asphalt blowing operations directly to the atmosphere via a bypass line when the incinerator is offline to allow personnel a brief period of time to shut down the asphalt blowing operations**.** These periods are limited to thirty (30) minutes each. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]

49. When operating under this alternate scenario, the permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with recordkeeping provisions of this section. [§19.501 of Regulation 19 et seq., and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr
824A	VOC	636

50. The facility may operate under this alternate scenario for a total of no more than 31 hours on an annual basis. §19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

51. The facility shall maintain a log to show all times that the facility is operating under the alternate operating scenario. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

52. Records for the alternate operating scenario shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-825

#16 Asphalt Blowing Furnaces

Source Description

SN-825 is the combined emissions of three furnaces used to maintain the required temperature during the blowing operation. They have a combined heat input of 30 MMBtu/hr (nominal design) and are fueled by pipeline quality natural gas or desulfurized refinery fuel gas. Two of the furnaces were installed in 1945. The other was installed in 1946.

Regulations

This source is not subject to 40 C.F.R., Subpart J- *Standards of Performance for Petroleum Refineries* because each of the three furnaces was constructed prior to the effective date.

The blowing stills associated with the furnaces are not subject to 40 C.F.R., Subpart UU- *Standards of Performance for Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture* because they were constructed prior to the effective date.

Specific Conditions

53. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the fuel limits for this source. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
825	#16 Asphalt Blowing Furnaces		
	PM_{10}	1.0	4.4
	SO_2	1.3	5.0
	VOC	1.0	4.4
	CO	3.2	10.9
	NO_X	5.5	18.4

54. The facility shall use pipeline quality natural gas or desulfurized refinery fuel gas (as defined by Plantwide Condition #8(a)) as fuel for this source. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

55. The facility shall not exceed 5% opacity from the sources in this section burning pipeline quality natural gas or desulfurized refinery fuel gas. Compliance with this limit shall be demonstrated by burning only pipeline quality natural gas or refinery fuel gas. If the H_2S concentration of the refinery fuel gas exceeds 1000 mg/dscm (0.435 gr/dscf), then the facility shall comply with Plantwide Condition #12. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

56. The #11 Deasphalting Furnace is an affected facility under the provisions of 40 C.F.R. 60, Subpart J-*Standards of Performance for Petroleum Refineries*. It is defined in the subpart as a fuel gas combustion device. This source is subject to the Subpart J requirements, which are summarized in Specific Condition #54 and below (for the full regulation, see Appendix C): [§19.304 of Regulation 19 and 40 CFR §60.100]

    a. The facility shall install, calibrate, maintain and operate a continuous monitoring system for SN-825 in accordance with the provisions of § 60.105 outlined below. [§60.105(a)(4)]

        i. The CEM system shall monitor the concentration (dry basis) of H_2S in fuel gases prior to being burned in any fuel gas combustion device.

        ii. The span value for this instrument shall be 425 mg/dscm H_2S.

        iii. All fuel gas combustion devices having a common source of fuel gas may be monitored at only one location if monitoring at this location accurately represents the concentration of H_2S in the fuel gas burned at each source.

    b. Pursuant to § 60.105(e), for purposes of reports under § 60.7(c), periods of excess emissions for sulfur dioxide from fuel gas combustion shall be determined and reported as required by § 60.105(e)(3).

    c. Pursuant to § 60.106(a), in conducting the performance tests required in § 60.8, the facility shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

    d. Pursuant to § 60.106(e), the owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11 (or other approved method) shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

e. Pursuant to § 60.106(f), the facility shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in § 60.104(a)(2) by § 60.106(f)(1), (2), and (3).

f. Pursuant to § 60.106(f)(1), Method 6 (or other approved method) shall be used to determine the SO_2 concentration. The concentration in mg/dscm (lb/dscf) obtained by Method 6 (or other approved method) is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m^2 (54 ft^2) or at a point no closer to the walls than 1.00 m (39 in.) if the cross-sectional area is 5.00 m^2 or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases. The sampling point for Method 4 (or other approved method) shall be adjacent to the sampling point for Method 6 (or other approved method). The sampling time for each sample shall be equal to the time it takes for two Method 6 (or other approved method) samples. The moisture content from this sample shall be used to correct the corresponding Method 6 (or other approved method) samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 (or other approved method) shall be used following the procedures of paragraph (f)(2) of this section.

g. Pursuant to § 60.106(f)(2), Method 15 (or other approved method) shall be used to determine the reduced sulfur and H_2S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 (or other approved method) in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

h. Pursuant to § 60.106(f)(3), the oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 (or other approved method). The samples shall be taken simultaneously with the SO_2, reduced sulfur and H_2S, or moisture samples. The SO_2, reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(3) of this section.

SN-831

#9 Continuous Catalyst Regenerator (CCR)

Source Description

SN-831 is a regenerator used to continuously burn off the coke deposit from the catalyst, and restore catalyst activity, selectivity, and stability. This source was installed in 1991. Usage of a new catalyst was implemented in 2003/2004 in order to produce additional hydrogen for the No. 8 and No. 10 hydrotreating processes.

Specific Conditions

57. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limit for this source. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
831	#9 Continuous Catalyst Regenerator		
	PM_{10}	2.0	8.8
	SO_2	2.0	8.8
	VOC	2.0	8.8
	CO	2.6	11.4
	NO_X	2.0	8.8

58. The total amount of catalyst recirculated at this source shall be limited to 13.2 million pounds per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

59. Records for the recirculation rate shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-832

47 Asphalt Tank Heaters

Source Description

SN-832 is comprised of 47 tank heaters with a total heat input capacity of 99.3 MMBtu/hr (nominal design). The heaters are used to maintain elevated temperatures of stored asphalt products so that the material will flow and not solidify. The heaters included in this source grouping are described in the following table.

Tank SN	Year Installed	# of Heaters	MMBtu/hr per heater	total MMBtu/hr per tank
T-39	pre-1981	2	3.0	6.0
T-40	1988	1	2.3	2.3
T-41	1991	1	2.3	2.3
T-56	1989	2	1.5	3.0
T-78	1999	3	0.68	2.1
T-99	1991	2	0.15	0.3
T-107	1987	4	2.75	11.0
T-111	pre-1981	4	1.8	7.2
T-118	1987	4	2.75	11.0
T-219	1968	4	1.8	7.2
T-348	1968	2	2.3	4.6
T-354	2001	2	1.5	3.0
T-524	1986	4	2.3	9.2
T-530	1986	4	2.3	9.2
T-544	1991	2	0.5	1.0
T-548	1993	6	3.33	20

Because the combined emissions from these sources emit more than 10 tpy of a single criteria pollutant, they cannot be classified as insignificant emission sources. These sources have been permitted at full capacity and fire only pipeline quality natural gas or desulfurized refinery fuel gas.

Regulations

These sources are subject to 40 C.F.R., Subpart J- *Standards of Performance for Petroleum Refineries* as fuel gas combustion devices.

Specific Conditions

60. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by permitting these sources at full capacity and compliance with NSPS Subpart J. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
832	47 Asphalt Tank Heaters		
	PM_{10}	1.0	4.4
	SO_2	4.3	14.7
	VOC	1.0	4.4
	CO	10.6	35.9
	NO_X	12.9	43.6

61. The facility shall not exceed 5% opacity from the sources in this section burning pipeline quality natural gas or desulfurized refinery fuel gas. Compliance with this limit shall be demonstrated by burning only pipeline quality natural gas or refinery fuel gas. If the H_2S concentration of the refinery fuel gas exceeds 1000 mg/dscm (0.435 gr/dscf), then the facility shall comply with Plantwide Condition #12. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

62. The facility shall burn only pipeline quality natural gas or desulfurized refinery fuel gas (as defined by Plantwide Condition #8(a)) at the sources included in SN-832. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

63. This source is an affected facility under the provisions of 40 CFR Part 60 Subpart J – *Standards of Performance for Petroleum Refineries*. It is defined in the Subpart as a fuel gas combustion device. For the full regulation, see Appendix C. This source is subject to

the Subpart J requirements, which are summarized below. [§19.304 of Regulation 19 and 40 CFR §60.100]

a. Pursuant to § 60.104(a)(1), the sources shall not burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

b. Pursuant to § 60.105(a), the facility shall install, calibrate, maintain and operate continuous monitoring systems in accordance with the provisions of § 60.105 outlined below.

c. Pursuant to § 60.105(a)(3), the facility shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere (except where an H_2S monitor is installed under paragraph (a)(4) of this section) from the flares. The monitor shall include an oxygen monitor for correcting the data for excess air.

   i. The span values for this monitor are 50 ppm SO_2 and 10 percent oxygen (O_2).

   ii. The SO_2 monitoring level equivalent to the H_2S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

   iii. The performance evaluations for this monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 and 3 (or other approved methods) shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

   iv. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

d. Pursuant to § 60.105(a)(4), the facility may, in place of the SO_2 monitor in paragraph (a)(3), install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device.

   i. The span value for this instrument is 425 mg/dscm H_2S.

   ii. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location; if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

iii. The performance evaluations for this H_2S monitor under § 60.13(c) shall use Performance Specification 7. Method 11 (or other approved method) shall be used for conducting the relative accuracy evaluations.

e. Pursuant to § 60.105(e), for purposes of reports under § 60.7(c), periods of excess emissions for sulfur dioxide from fuel gas combustion shall be determined and reported as required by § 60.105(e)(3).

f. Pursuant to § 60.106(e), the owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11 (or other approved method) shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

g. Pursuant to § 60.106(f), the facility shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in § 60.104(a)(2) by § 60.106(f)(1), (2), and (3).

i. Pursuant to § 60.106(f)(1), Method 6 (or other approved method) shall be used to determine the SO_2 concentration. The concentration in mg/dscm (lb/dscf) obtained by Method 6 (or other approved method) is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m^2 (54 ft^2) or at a point no closer to the walls than 1.00 m (39 in.) if the cross-sectional area is 5.00 m^2 or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases. The sampling point for Method 4 (or other approved method) shall be adjacent to the sampling point for Method 6 (or other approved method). The sampling time for each sample shall be equal to the time it takes for two Method 6 (or other approved method) samples. The moisture content from this sample shall be used to correct the corresponding Method 6 (or other approved method) samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 (or other approved method) shall be used following the procedures of paragraph (f)(2) of this section.

ii. Pursuant to § 60.106(f)(2), Method 15 (or other approved method) shall be used to determine the reduced sulfur and H_2S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 (or other approved method) in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 (or other approved method) samples.

iii. Pursuant to § 60.106(f)(3), the oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 (or other approved method). The samples shall be taken simultaneously with the SO_2, reduced sulfur and H_2S, or moisture samples. The SO_2, reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(3) of this section.

SN's-833 through 841

South XVG Compressor, North KVG Compressor, South KVG Compressor, 8GTL Compressor, North 8SVG Compressor, South 10SVG Compressor, East JVG Compressor, West JVG Compressor, G398TA Air Compressor

Source Description

All of the following described sources are pipeline quality natural gas compressor engines used to move gases within refinery plant operations. They are all fueled by pipeline quality natural gas.

The consent decree reached between Lion Oil, the US EPA, and ADEQ required that Lion install and operate controls on SN-837, SN-838, SN-839, and SN-840 as an "environmentally beneficial project". Additionally, a BACT analysis was performed for CO emissions from the Air Compressor (SN-841), and BACT was proposed to be the installation of non-selective catalytic reduction (NSCR) with air/fuel ratio controls. EPA has not yet granted final approval of the proposed BACT for SN-841, and the unit will operate under an interim CO emission limit of 2.0 g/hp-hr until such time as a final BACT limit is established.

The installation of these control devices will result in decreases in both actual and permitted emissions of CO and NO_x from these engines.

Compressor SN	Year Installed	rated power (hp)
833*	1959	--
834	1942	660
835	1942	660
836	1986	1100
837	1958	440
838	1958	550
839	1959	240
840	1959	240
841	1981	700

*** Source removed from Service. See S.C. #95.**

In order to comply with the NAAQS, the facility has chosen to limit emissions from several of the sources in this section. These limits are specified in the following Specific Conditions.

Specific Conditions

64. The permittee shall not exceed the emission rates set forth in the following tables. The permittee shall comply with the emission limits contained in Table 102.1 below until December 31, 2004. On and after December 31, 2004, the facility shall be subject to, and shall comply with the limits contained in Table 102.2. Under no circumstances shall the limits of Table 102.1 apply on or after December 31, 2004. Compliance with these limits shall be demonstrated by compliance with the operation and testing limits of this section. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

Table 102.1 - Emission Limitations prior to December 31, 2004			
SN	Pollutant	lb/hr	tpy
833	South XVG Compressor Source Removed from Service		
834 and 835 (combined)	CO	---	21.2
	NO_X	---	25.8
834	North KVG Compressor		
	CO	23.6	—
	NO_X	28.7	—
835	South KVG Compressor		
	CO	23.6	—
	NO_X	28.7	—
836	8GTL Compressor		
	CO	18.2	34.2
	NO_X	21.1	39.6
837 and 838 (combined)	North 8SVG Compressor and South 10SVG Compressor		
	CO	---	86.7

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

Table 102.1 - Emission Limitations prior to December 31, 2004			
SN	Pollutant	lb/hr	tpy
	NO_X	---	50.9
837	North 8SVG Compressor		
	CO	19.4	---
	NO_X	11.4	---
838	South 10SVG Compressor		
	CO	19.4	---
	NO_x	11.4	---
839	East JVG Compressor		
	CO	9.0	39.7
	NO_X	5.6	24.5
840	West JVG Compressor		
	CO	9.0	39.7
	NO_X	5.6	24.5
841	G398TA Air Compressor		
	CO	20.3	89.0
	NO_X	12.5	55.0

Table 102.2 - Emission Limitations on and after December 31, 2004			
SN	Pollutant	lb/hr	tpy
833	South XVG Compressor Source Removed from Service		
834 and 835 (combined)	CO	---	21.2

Table 102.2 - Emission Limitations on and after December 31, 2004			
SN	Pollutant	lb/hr	tpy
	NO_X	---	25.8
834	North KVG Compressor		
	CO	23.6	—
	NO_X	28.7	—
835	South KVG Compressor		
	CO	23.6	—
	NO_X	28.7	—
836	8GTL Compressor		
	CO	18.2	34.2
	NO_X	21.1	39.6
837	North 8SVG Compressor w/Catalytic Converter		
	CO	2.9	12.8
	NO_X	1.9	8.5
838	South 10 SVG Compressor w/Catalytic Converter		
	CO	3.6	16.0
	NO_X	2.4	10.7
839	East JVG Compressor		
	CO	1.6	7.0
	NO_X	1.1	4.6
840	West JVG Compressor		
	CO	1.6	7.0
	NO_X	1.1	4.6
841	G398TA Air Compressor		

Table 102.2 - Emission Limitations on and after December 31, 2004			
SN	Pollutant	lb/hr	tpy
	CO	3.1	13.6
	NO_X	3.1	13.6

Negligible amounts of particulate matter and sulfur dioxide may be emitted by these sources. Due to extremely low potential emissions of these pollutants, numerical limits have not been included for these sources, but such emissions are not prohibited**.**

65. The facility shall not exceed 5% opacity from SN's 833-841. Compliance with this limit shall be demonstrated by burning only pipeline quality natural gas. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and §8-4-311]

66. The combined operation of SN's 834 and 835 shall be limited to a total of 1,800 hours of operation per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. § 70.6]

67. Meters shall record the hours of operation of SN-834 and SN-835, and records of hours of operation shall be kept on a monthly basis. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

68. The 8GTL Compressor (SN-836) shall be limited to 3.6 MM hp-hr per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and §8-4-311, and 40 C.F.R. § 70.6]

69. Records for the annual firing rate of SN-836 shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

70. The facility shall use only pipeline quality natural gas as fuel for SN's 834-841. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and §8-4-311, and 40 C.F.R. § 70.6]

71. Every five years beginning in June 2006, the permittee shall simultaneously conduct tests for CO and NO_X for SN-836 in accordance with Plantwide Condition #3. EPA Reference Method 7E (or other approved method) shall be used to test NO_X for the reciprocating engines and EPA reference Method 10 (or other approved method) shall be used to determine CO. The permittee shall test the engine within 90% of its rated capacity. If the tests are not performed within this range, the permittee shall be limited to operating within 10% above the tested rate. [§19.702 of Regulation 19 and 40 C.F.R., Part 52, Subpart E]

EPA Reference Method 19 shall be used to convert test results to lbs/hr and tpy. All written reports shall be submitted to the following address:

Arkansas Department of Environmental Quality
Air Division
Attn.: Air Enforcement Section
PO Box 8913
Little Rock, Arkansas 72219

72. Every five years beginning in June 2006, the permittee shall simultaneously conduct tests for CO and NO_x on one-half of each type of compressor engine (except SN-836) in accordance with Plantwide Condition #3. EPA Reference Method 7E (or other approved method) shall be used to test NO_x for the reciprocating engines and EPA reference Method 10 (or other approved method) shall be used to determine CO. The permittee shall test the engines within 90% of their rated capacity. If the tests are not performed within this range, the permittee shall be limited to operating within 10% above the tested rate. The Department reserves the right to select the engine(s) to be tested. The engine(s) tested shall be rotated so that no engine(s) is tested twice before an engine of equal HP is tested once. If the tested emission rate for any pollutant is in excess of the permitted emission rate, all similar engines shall be tested for both pollutants. This condition shall not apply to the air compressor (SN-841). [§19.702 of Regulation 19 and 40 C.F.R., Part 52, Subpart E]

Test results shall be furnished in lbs/hr and converted to tpy. EPA Reference Method 19 shall be used to convert test results to lbs/hr and tpy. All written reports shall be submitted to the following address:

Arkansas Department of Environmental Quality
Air Division
Attn.: Air Enforcement Section
PO Box 8913
Little Rock, Arkansas 72219

73. In order to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) for NO_X and PM_{10}, the South XVG Compressor (SN-833) has been removed from service. SN-833 may not be placed back into service unless the permit is modified. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and §8-4-311, and 40 C.F.R. § 70.6]

74. In order to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) for NO_X and PM_{10}, the facility has bubbled the emissions of the North KVG Compressor (SN-834) and South KVG Compressor (SN-835) and has taken the emission limits listed in the tables in this section. The emission limits for SN-834 and SN-835 may not be increased unless the permit is modified. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and §8-4-311, and 40 C.F.R. § 70.6]

75. The permittee shall install, operate, and properly maintain catalytic converters with air-to-fuel ratio controls on SN-837, SN-838, SN-839, and SN-840 for the purpose of reducing emissions of NOx and CO to the atmosphere. These controls shall be installed and

operational no later than December 31, 2004. [§19.303 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and Section VIII(A) of the consent decree agreement]

76. The permittee shall install, operate, and properly maintain a catalytic converter with air-to-fuel ratio controls on the Air Compressor (SN-841) for the purpose of reducing CO emissions to the atmosphere. These controls shall be installed and operational no later than December 31, 2004. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

77. On and after December 31, 2004, until such time as a final BACT limit for CO is established by the US EPA, the permittee shall operate the Air Compressor (SN-841) such that CO emissions to the atmosphere do not exceed 2.0 g/hp-hr based on a 3-hour average. Once a final BACT limit is established by the US EPA, then the permittee shall comply with that limit. [§19.501 et seq and 40 CFR Part 52 Subpart E]

78. Within 60 days after the installation of controls on the air compressor (SN-841) the permittee shall test the compressor exhaust stack for emissions of CO and NO_x. CO testing shall be performed in accordance with US EPA Reference Method 10, and NO_x testing shall be performed in accordance with US EPA Reference Method 7E. EPA Reference Method 19 shall be used to convert test results to mass emission rates. The results of this testing shall be maintained on-site, and shall be submitted to the Department in accordance with General Provision #7. [§19.702 of Regulation 19 and 40 CFR Part 52 Subpart E]

79. The permittee shall continue to test the CO emissions from the Air Compressor (SN-841) according to the following schedule. All CO testing shall be performed in accordance with US EPA Reference Method 10. EPA Reference Method 19 shall be used to convert test results to mass emission rates. All test results shall be maintained on-site, and shall be submitted to the Department in accordance with General Provision #7. [§19.702 of Regulation 19 and 40 CFR Part 52 Subpart E]

    l. A test shall be performed within 30 days prior to the beginning of the first scheduled semi-annual maintenance of the compressor (SN-841). During the maintenance downtime, the catalytic converter shall be serviced in accordance with the manufacturer's directives.

    m. An additional test shall be performed within 30 days following the end of the first scheduled semi-annual maintenance of the compressor (SN-841).

    n. The testing procedures outlined in (a) and (b) above shall be repeated for the second scheduled semi-annual maintenance of the air compressor (SN-841). During the maintenance downtime, the catalytic converter shall be serviced in accordance with the manufacturer's directives.

    o. The testing shall be repeated again within 30 days prior to the beginning of the fourth scheduled semi-annual maintenance of the air compressor (after the catalytic converter is installed).

p. All of the above testing shall be completed no later than 30 months after the date that the air compressor is installed and first operated.

q. The air compressor (SN-841) shall continue to be tested for CO on an annual basis from the date that the test required in section (d) above is completed.

80. Each catalytic converter system operated on a stationary engine at the Lion Oil facility shall be operated and maintained in accordance with the manufacturer's specifications and directives at all times. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-846

Gasoline/Diesel Loading Rack

Source Description

SN-846 is gasoline and diesel loading rack. It was installed in 1980. A John Zink Carbon Adsorption Vapor Recovery Unit (VRU) was placed into operation on June 18, 1998, in order to comply with the requirements of 40 C.F.R. 63, Subpart CC-*National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*. The requirements of Subpart CC are outlined in the Plantwide Conditions of this permit.

Regulations

This source is not subject to 40 C.F.R. 60, Subpart XX-*Standards of Performance for Bulk Gasoline Terminals* because it was constructed prior to the effective date of Subpart XX.

Specific Conditions

81. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with 40 C.F.R. 63, Subpart CC and the throughput and loading requirements for this source. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
846	VOC	20.2	17.1

82. The total annual throughput of gasoline/diesel products through this source is limited to 9,761,905 bbl per consecutive twelve month period. [§19.705, A.C.A. §8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

83. Records for the annual throughput shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E]

84. The facility shall only load gasoline and diesel products at this loading rack. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

85. The facility shall operate a TOC CEM system on the gasoline/diesel loading rack in order to demonstrate compliance with 40 CFR Part 63 Subpart CC. All CEMs shall be operated in accordance with the Department's CEM Standards. The facility shall submit CEM data in accordance with the Department's Standards. CEM data shall be submitted to

demonstrate that the TOC concentration is less than or equal to 1.1 volume percent. [§19.304 of Regulation 19 and 40 CFR §63.427(a) and (b)]

SN-847

Heavy Oil Loading Racks

Source Description

SN-847 is the aggregate emissions of twelve asphalt plant loading racks. The loading racks are described in the following table.

Year Installed	Product Loaded
1987	111/219 East Asphalt Truck Rack
Pre-1950	111/219 West Asphalt Truck Rack
Pre-1950	South Asphalt Plant Truck Rack
1975	North PMA Truck Rack*
1989	North Asphalt Plant Truck Rack
Pre-1950	Pumphouse Truck Rack
1986	Lube Oil Truck Rack
Pre-1950	E & W Rail Car Rack
1968	56 Rack
Pre-1950	Protective Coatings Dock
Pre-1950	Asphalt Dock
2000	South PMA Truck Rack

***The PMA Truck Rack was previously known as the Emulsion Plant Truck Rack.**

Specific Conditions

86. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the Plantwide Applicability Limit (PAL) for these sources. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
847	Heavy Oil Loading Racks		
	VOC	647.2	281.1

87. The facility shall load only asphalt, solvents, and lube oil-type products at these loading racks. [§19.705 of Regulation 19, A.C.A. § 8 -4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

88. The PAL limits the total emissions from the loading racks in this section to 281.1 tons of VOC emissions per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. § 70.6]

89. The facility has elected to demonstrate compliance for the loading racks through a PAL. To demonstrate compliance with the PAL, the facility shall maintain a monthly inventory of the emissions from each loading rack in this section. This inventory shall be calculated by the methods and equations used in AP-42, 5th Edition, Chapter 5.2, "Transportation and Marketing of Petroleum Liquids." Records for the monthly inventory of emissions from each loading rack shall include the source name, products loaded, monthly throughput, and monthly emissions in pounds and tons. The emissions from this inventory shall be summed to determine the total amount of emissions from the combined loading racks. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

90. Records for the annual VOC emission rate and individual loading rack inventory shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

91. In order to maintain that the increase in emissions from the PMA project are below PSD trigger limits and do not cause a significant increase in emissions at the asphalt loading racks, the performance graded polymer modified asphalt (PGPMA) through the two PMA Asphalt Truck Racks shall be limited to an annual throughput of 1.2 MM bbl. [§19.901 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

92. Records for the PGPMA throughput shall be maintained on a daily basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-848

#7 FCCU Catalyst Hopper Vents

Source Description

SN-848 is the vent system for two storage bins used to store catalyst in the catalytic cracking process. It was installed in 1973.

Specific Conditions

93. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section.

SN	Pollutant	lb/hr	tpy
848	#7 FCCU Catalyst Hopper Vents		
	PM_{10}	25.0	1.8

94. The total throughput of catalyst at this source shall be limited to 3,650 tons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

95. Records of the amount of catalyst shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-849

Standby Diesel Crude Pump

Source Description

SN-849 is a Standby Diesel Crude Pump to be used as a backup to the primary charge pump (electrical) in the event of power failure or other related operational emergencies. This unit is rated at 325 hp and is fueled by diesel oil. This unit is fueled by low-sulfur diesel fuel provided from the low-sulfur diesel storage tank. The Standby Diesel Crude Pump was installed in 1997.

Specific Conditions

96. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput and fuel usage limits of this section. [§19.501 of Regulation 19 *et seq*., and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
849	Standby Diesel Crude Pump		
	PM_{10}	1.4	1.4
	SO_2	1.2	1.2
	VOC	1.6	1.5
	CO	12.2	11.6
	NO_X	20.2	19.1

97. The facility shall not exceed 20% opacity from this source. As this source operates for only a short period of time each year, a regular compliance demonstration is not necessary. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

98. The total hours of operation for this source shall be limited to 1900 hours per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

99. A meter shall be operated to record the hours of operation of SN-849. Records of the hours of operation shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7.

[§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E, within 180 days of issuance of Permit #868-AOP-R1]

100. This source shall only be fired on fuel which contains less than 0.5 percent sulfur. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

101. The facility shall keep records demonstrating the sulfur content of the fuel used at the Standby Diesel Crude Pump (SN-849). These records may be in the form of laboratory analyses performed on the fuel stored in the low-sulfur diesel storage tank which supplies fuel to this unit. If any alternative source of fuel is used to fire this unit, the alternative source and the sulfur content of the alternative fuel shall be documented. These records shall be maintained on-site and shall be made available to Department personnel upon request. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-851 and 851a

Wastewater Collection, Storage, and Treatment

Source Description

SN-851, the waste water treatment facility, is used to remove pollutants from refinery waste water. It was installed in the 1970's. This unit has a maximum design capacity of 2500 gallons per minute (GPM), which corresponds to an annual capacity of 1,317.5 MM gal. In order to account for any short-term operational variances at this source, a safety factor of 20% has been included in the lb/hr emission limitation (corresponding to a short-term throughput of 3000 GPM).

Lion Oil has begun a complete redesign of the water treatment systems at the facility. This redesign, once completed, will completely segregate the process wastewater from the stormwater at the facility. This redesign will also greatly reduce emissions from the wastewater treatment processes at the facility due to the enclosure of the water treatment systems. As part of the new wastewater systems, 6 new tanks will be installed at the facility. These tanks have been designated T-275, T-276, T-277, T-278, T-279, and T-280. Due to the enclosure of the process water treatment system, these 6 new tanks will be the only new emission points associated with the newly installed system. The new system will handle the facility process wastewater, while the existing system will continue to be used for the treatment of facility stormwater.

Until the new wastewater treatment system is fully operational, the existing system will continue to be operated as indicated in this permit. In order to allow for the operation of the new, enclosed wastewater system once it is constructed, a separate set of specific conditions which are applicable to the new system have been added to this permit. The facility will be required to comply with both sets of specific conditions until such time as the permit is formally amended to modify the requirements for the “old” wastewater treatment system.

Specific Conditions

“Old” Wastewater Treatment System

102. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section.

SN	Pollutant	lb/hr	tpy
851	Wastewater Treatment		
	VOC	900	3293.8

103. The total throughput of wastewater at this source shall be limited to 1,317.5 MM gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

104. Records of the wastewater throughput shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

"New" Wastewater Treatment System

105. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [§19.501 of Regulation 19 *et seq*., and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
851a	Wastewater Treatment		
	VOC	26.1	85.9

106. The total throughput of wastewater at this source shall be limited to 1,064.6 MM gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

107. Records of the wastewater throughput shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

108. The "new" process wastewater treatment system shall be designed, installed, and operated in compliance with the applicable provisions of 40 CFR Part 60 Subpart QQQ - *Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (Appendix J)*. The record keeping and reporting requirements of this subpart are summarized below. [§19.304 of Regulation 19 and 40 CFR §60.090]

    a. For each individual drain system or junction box subject to the requirements of §60.692-2, the location, date, and corrective action shall be recorded for each drain when a problem is identified that could result in VOC emissions as determined in the initial and periodic visual or physical inspections.

    b. For each junction box subject to the requirements of §60.692-2, the location, date, and corrective action shall be recorded for inspections required by §60.692-2(b) when a problem is identified that could result in VOC emissions.

c. For each sewer line subject to the requirements of §60.692-2 and §60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by §§60.692-2(c) and 60.693-1(e) when a problem is identified at could result in VOC emissions.

d. For oil-water separators subject to §60.692-3 the location, date, and corrective action shall be recorded for inspections required by §60.692-3(a) when a problem is identified that could result in VOC emissions.

e. For closed vent systems subject to §60.692-5 and completely closed drain systems subject to §60.693-1, the location, date, and corrective action shall be recorded for inspections required by §60.692-5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.

f. If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.

g. If an emission point is not repaired in the specified amount of time, the reason for the delay as specified in §60.692-6 shall be recorded, along with the signature of the owner or operator whose decision it was that repair could not be effected without a refinery or process shutdown, and the date that the repair or corrective action was successfully completed.

h. A Copy of the design specifications for all equipment used to comply with the provisions of Subpart QQQ shall be kept for the life of the source in a readily accessible location. These records shall include the following information:

   i. Detailed schematics and piping and instrumentation diagrams.

   ii. The dates and descriptions of any changes in the design specifications.

i. Additional information shall be maintained for specific equipment as indicated in 40 CFR §60.697 (f)(3)(i)-(x).

j. If the permittee elects to install a tightly sealed cap or plug over a drain that is out of active service, the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which indicate the location of such drains.

k. For stormwater sewer systems subject to the exclusion in §60.692-1(d)(1), the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

l. For ancillary equipment subject to the exclusion in §60.692-1(d)(2), the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.

m. For non-contact cooling water systems subject to the exclusion in §60.692-1(d)(3), the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

n. The permittee shall submit to the Department within 60 days after initial startup of the "new" wastewater treatment system a certification that the equipment necessary to comply with the standards of Subpart QQQ has been installed and that all necessary initial inspections have been conducted in accordance with these standards.

o. After the initial certification, the permittee shall submit semiannually a certification that all of the required inspections have been carried out in accordance with the standards of Subpart QQQ.

109. The permittee shall notify the Air Division Permit Section no later than 60 days prior to beginning operation of the "new" wastewater treatment system. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

110. The permittee shall submit an annual report to the Department which details the progress of the installation of the "new" wastewater treatment system. This report shall indicate the degree of completion of the "new" wastewater treatment system, as well as an up-to-date emission estimate for the "old" wastewater treatment system based on the current operating conditions at the refinery. The Department shall reserve the right to modify the permitted emission limitations for the "old" wastewater treatment system based on the information contained in this report. This report shall be submitted by August 1 of each calendar year. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN-853

Cooling Towers (except SN-859)

Source Description

The # 3, 5, 6, 7, and 17 Sulfur Plant cooling towers are used to transfer waste heat from the cooling water to the atmosphere. They were installed in the 1970's. The #1 Cooling Tower was removed from service in 2003 and replaced with the new #8 cooling tower, which has been designated as SN-859. The cooling water circulation limit for the remaining cooling towers has been reduced by the amount formerly utilized through the #1 tower with this modification.

Specific Conditions

111. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [§19.501 of Regulation 19 *et seq*., and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
853	Cooling Towers		
	VOC	24.7	108.7
	PM_{10}	90.8	356.0

112. The total amount of water circulated at the #3, 5, 6, 7, and 17 Sulfur Plant cooling towers shall be limited to 36.30 billion gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

113. Records of the water circulated shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E, beginning April 2, 2001]

SN-854

Fugitive Equipment Leaks

Source Description

The fugitive emissions not quantified with the other sources are included in this grouping. The fugitive emissions associated with the #10 unit, which were previously included in this fugitive emissions bubble (91.6 tpy), have been removed and are now included in the new Tier II Fugitives and Tanks VOC Bubble (SN-858) along with all new fugitive emission sources associated with the Tier II project. All fugitive emissions from the facility (Including Tier II fugitives) continue to be subject to the 970.5 lb/hr emission limit for SN-854.

Specific Conditions

114. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by an annual emissions inventory and the conditions of 40 C.F.R.60, Subparts GGG and VV, as referenced by Subpart GGG and 40 C.F.R. 63, Subpart CC, for those components subject to the requirements of Subparts GGG, VV or CC (respectively). [§19.501 of Regulation 19 *et seq*., and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
854	Fugitive Equipment Leaks		
	VOC	970.5*	4159.4

*** This limit includes fugitives from the Tier II fugitive emission sources (SN-858).**

115. The facility shall conduct an annual emission inventory to demonstrate compliance with the emission limits of Specific Condition #114. This inventory shall be calculated by the methods and equations used in AP-42, Chapter 5.1 (5^{th} Edition or later version) or *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017 (November 1995 or later version), or other ADEQ-approved method. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. 70.6]

116. Records for the emission inventory required in Specific Condition #115 shall be maintained on an annual basis. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), beginning in year 2003, and shall be submitted to the Department at the following address no later than August 1 of each year. [§19.705 of Regulation 19 and 40 C.F.R. Part 52, Subpart E]

Arkansas Department of Environmental Quality
Air Division
Attn: Compliance Inspector Supervisor
Post Office Box 8913
Little Rock, AR 72219

117. The equipment, including each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service in the #4 Crude Unit, #6 Hydrotreater/Isomerization Unit, #12 Distillate Hydrotreater, #17 Sulfur Recovery Plant and the Polymer Asphalt Letdown Facility, are affected facilities under the terms of 40 CFR Part 60 Subpart GGG – *Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries*. For the purposes of recordkeeping and reporting only, compressors are also considered affected facilities (see Appendix F). The facility is subject to the Subpart GGG requirements, which are summarized below. [§19.304 of Regulation 19, and 40 CFR §60.590(a)(1) and (3)]

    a. Pursuant to § 60.592(a), the facility shall comply with the standards for specific equipment found in §§ 60.482-1 to 60.482-10 of 40 C.F.R. 60, Subpart VV.

    b. Pursuant to § 60.592(b), an owner or operator may elect to comply with the alternative standards for valves in §§ 60.483-1 and 60.483-2.

    c. Pursuant to § 60.592(c), an owner or operator may apply to the Administrator for a permit modification for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of § 60.484.

    d. Pursuant to § 60.592(d), each owner or operator subject to the provisions of this subpart shall comply with the testing provisions of § 60.485 except as provided in § 60.593.

    e. Pursuant to § 60.592(e), each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping and reporting provisions of §§ 60.486 and 60.487.

    f. Pursuant to § 60.593(a), each owner or operator subject to the provisions of this subpart may comply with the allowable exceptions to the provisions of subpart VV.

118. This facility is subject to 40 CFR Part 60 Subpart VV-*Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry* as referenced by Subpart GGG (see Appendix G). The facility is subject to the requirements of Subpart VV which are summarized below. [§19.304 of Regulation 19, and 40 CFR §§60.590 and 60.592]

    a. Pursuant to § 60.482-1(a), the facility shall demonstrate compliance with the requirements of §§ 60.482-1 to 60.482-10 for all equipment within 180 days of initial startup.

b. Pursuant to § 60.482-1(b), compliance with §§ 60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485.

c. Pursuant to § 60.482-1(c)(1), the facility may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in § 60.484. *(Note: This will require a permit modification.)*

d. Pursuant to § 60.482-1(c)(2), if the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, or 60.482-10, the facility shall comply with the requirements of that determination. *(Note: This will require a permit modification.)*

e. Pursuant to § 60.482-3(a), the compressors in hydrogen service are not subject to this subpart as per the exemption of § 60.593(b)(1).

f. Pursuant to § 60.482-4, the facility has no pressure relief devices in gas/vapor service and is not subject to this section.

g. Pursuant to § 60.482-6(a)(1), each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1(c).

h. Pursuant to § 60.482-6(a)(2), the cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

i. Pursuant to § 60.482-6(b), each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

j. Pursuant to § 60.482-6(c), when a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times.

k. Pursuant to § 60.482-7, the facility shall comply with the requirements for valves in gas/vapor service or in light liquid service.

l. Pursuant to § 60.482-10, the facility shall comply with the requirements for closed vent systems and control devices.

m. Pursuant to § 60.483-2, the facility has elected to comply with the alternative work practice specified in paragraphs (b)(3) of this section.

n. Pursuant to § 60.483-2(2), the facility has notified the Administrator before implementing these alternative work practices, as specified in § 60.487(d).

o. Pursuant to § 60.483-2(b)(1), the facility has initially complied with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7.

p. Pursuant to § 60.483-2(b)(3), after 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

q. Pursuant to § 60.483-2(b)(4), if the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7 but can again elect to use this section.

r. Pursuant to § 60.485(a), in conducting the performance tests required in § 60.8, the facility shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

s. Pursuant to § 60.485(b), the facility shall determine compliance with the standards in §§ 60.482 and 60.483 as follows:

   i. Method 21 (or other approved method) shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 (or other approved method). The following calibration gases shall be used:

      1. Zero air (less than 10 ppm of hydrocarbon in air); and

      2. A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

t. Pursuant to § 60.485(c), the facility shall determine compliance with the no detectable emission standards in §§ 60.482-2(e), and 60.482-3(i) as follows:

   i. The requirements of paragraph (b) shall apply.

   ii. Method 21 (or other approved method) shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

   iii. Pursuant to § 60.485(f), samples used in conjunction with paragraphs (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

u. Pursuant to § 60.486(a)(1), the facility shall comply with the recordkeeping requirements of this section.

v. Pursuant to § 60.486(a)(2), an owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

w. Pursuant to § 60.486(b), when each leak is detected as specified in §§ 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply:

  i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

  ii. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7(c) and no leak has been detected during those 2 months.

  iii. The identification on equipment except on a valve, may be removed after it has been repaired.

x. Pursuant to § 60.486(k), the provisions of § 60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

y. Pursuant to § 60.487(a), the facility shall submit semiannual reports to the Administrator beginning six months after the initial start up date.

z. Pursuant to § 60.487(b), the initial semiannual report to the Administrator shall include the following information:

  i. Process unit identification.

    1. Number of valves subject to the requirements of § 60.482-7, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7(f).

    2. Number of pumps subject to the requirements of § 60.482-2, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2(e) and those pumps complying with § 60.482-2(f).

    3. Number of compressors subject to the requirements of § 60.482-3, excluding those compressors designated for no detectable emissions under the provisions of § 60.482-3(i) and those compressors complying with § 60.482-3(h).

aa. Pursuant to § 60.487(c), all semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486:

   i. Process unit identification.

   ii. For each month during the semiannual reporting period,

      1. Number of valves for which leaks were detected as described in § 60.482(7)(b) or § 60.483-2,

      2. Number of valves for which leaks were not repaired as required in § 60.482-7(d)(1),

      3. Number of pumps for which leaks were detected as described in § 60.482-2(b) and (d)(6)(i),

      4. Number of pumps for which leaks were not repaired as required in § 60.482-2(c)(1) and (d)(6)(ii),

      5. Number of compressors for which leaks were detected as described in § 60.482-3(f),

      6. Number of compressors for which leaks were not repaired as required in § 60.482-3(g)(1), and

      7. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

   iii. Dates of process unit shutdowns which occurred within the semiannual reporting period.

   iv. Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

bb. Pursuant to § 60.487(d), the facility has elected to comply with the provisions of § 60.483-2 and has notified the Administrator of the alternative standard selected 90 days before implementing the provision. If the facility decides to comply with the provisions of § 60.483-1, the facility shall notify the Administrator 90 days in advance before implementing the provisions.

cc. Pursuant to § 60.487(e), the facility shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that the facility must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

119. In order to demonstrate compliance with Subparts GGG and VV the facility shall maintain a log of the following. [§19.304 of Regulation 19, and 40 C.F.R. 60, Subparts GGG and VV]

a. Compliance with testing provisions as required by § 60.592(d).

b. Any exemptions for compressors considered to be in hydrogen service.

c. Any exemptions for equipment that is in vacuum service as provided by § 60.482-1(d).

d. Monthly monitoring results of § 60.482-2(a)(1).

e. Weekly visual inspection checks of liquids dripping of § 60.482-2(a)(2).

f. Record of instrument reading of § 60.482-2(b)(1).

g. Record of leaks from pump seal in § 60.482-2(b)(2).

h. Attempts to repair leak within 15 days as provided by § 60.482-2(c)(1).

i. Attempts to repair leak within 5 days as provided by § 60.482-2(c)(2).

j. Records of exemption for each pump equipped with a dual mechanical seal system as provided by § 60.482-2(d).

k. Records of exemption for any pump designated for no detectable emission as provided by § 60.482-2(e).

l. Records of exemption for any pump equipped with a closed vent system as provided by § 60.482-2(f).

m. Records that each sampling connection system is equipped with a closed purge system or closed vent system in §60.482-5(a) and (b) or qualifies for the exemptions.

n. All in-situ sampling systems that are exempt in § 60.482-5(c).

o. Record of monitoring of potential leaks within 5 days as required by § 60.482-8(a).

p. Record of leaks detected in § 60.482-8(b).

q. Attempts to repair leak within 15 days as provided by § 60.482-8(c)(1).

r. Attempts to repair leak within 5 days as provided by § 60.482-8(c)(2).

s. Record of delay of repair of equipment as allowed in § 60.482-9(a) or (b).

t. Record of delay of repair of equipment as allowed in § 60.482-9(c).

u. Record of delay of repair of equipment as allowed in § 60.482-9(d).

v. Delays of repair beyond a process unit shutdown as allowed in § 60.482-9(e).

w. Record of the percent of valves leaking as required in § 60.483-2(5) and (6).

x. Records of the tests and results of § 60.485(d).

y. Results of § 60.485.

z. Records of § 60.485(g).

aa. Information required by § 60.486(c) for leaks.

bb. Information required by § 60.486(d) for the design requirements for closed vent system/control device.

cc. Information required by § 60.486(e) for the equipment.

dd. Information required by § 60.486(f) for the valves.

ee. Information required by § 60.486(g) for the valves.

ff. Information required by § 60.486(h).

gg. Requirements to show that equipment is not in VOC service as provided by §60.486(j).

SN-856

Facility Tanks – Plantwide Applicability Limit (PAL)

Source Description

In order to demonstrate compliance with the emission limits for the tanks, the facility has decided to operate under a Plantwide Applicability Limit (PAL). The PAL is meant to allow the facility flexibility in operation and production while at the same time limiting the aggregate emissions from the tanks. The following is a summary of all tanks included in the PAL and the applicable regulations.

The Tank PAL has been modified with the Tier II low-sulfur fuels project in 2003/2004 in order to remove the following tanks: T-113, T-247, T-372, T-54, T-108, T-109, T-119, T-121, and T-122. As a result of the removal of these tanks from this PAL, the total annual VOC emission limit for this PAL was decreased from 7182.7 tpy to 6890.2 tpy.

In addition to the new and modified tanks associated with the Tier II project, one new 20,081 bbl slurry oil tank has been added to this source. This tank has been designated as T-82. Emissions from this tank were estimated at a worst-case amount of 18.3 tpy VOC. As a result of this addition, the tank PAL has been increased to 6908.5 tpy.

For simplicity, all of the tanks are described in the following table.

*Key FCR = Fixed Cone Roof
FDR = Fixed Dome Roof
FFR = Fixed Flat Roof
EFR = External Floating Roof
IFR = Internal Floating Roof
OR = Open Roof Tank
HOR = Horizontal Tank

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-3	FCR	1950	3,320	---
T-4	FCR	1953	4,890	---
T-7	EFR	1999	20,000	Kb
T-11	FCR	1959	4,930	---
T-12	FCR	1955	4,930	---
T-14	FCR	1942	2,997	---
T-15	FCR	1942	2,997	---

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-16	FCR	1950	4,412	---
T-17	FCR	1940	3,672	---
T-18	FCR	1949	3,160	---
T-19	FCR	2002	2,000	Kb
T-20	FCR	scheduled for removal, 2004		---
T-21	FCR	scheduled for removal, 2004		---
T-22	FCR	1953	1,930	---
T-23	FCR	1953	1,930	---
T-24	FCR	1999	3,059	UU see notes[iii]
T-25	FCR	1940	14,940	---
T-27	FCR	1950	3,553	---
T-36	IFR	1953	4,890	---
T-39	FCR	1958	4,890	---
T-40	FCR	1940	3,672	---
T-41	FCR	1940	3,672	---
T-46	HOR	1933	752	---
T-48	FCR	1923	1,120	---
T-49	FCR	1923	1,120	---
T-50	FCR	1937	9,984	---
T-51	FCR	1940	11,748	---
T-55	FFR	1923	15,090	---
T-56	FCR	1923	15,090	---
T-57	FCR	1949	10,330	---
T-58	FFR	1952	10,120	---

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-59	FCR	2002	8,200	Kb
T-60	FCR	1923	15,090	---
T-61	EFR	1949	20,160	---
T-62	EFR	1949	20,140	---
T-63	FCR	1957	8,602	---
T-64	IFR	1957	10,120	---
T-65	EFR	1954	10,120	---
T-70	FCR	1935	976	---
T-71	FCR	1935	976	---
T-72	FCR	1950	900	---
T-73	FCR	1950	900	---
T-74	FCR	1950	900	---
T-76	FCR	1938	36,293	---
T-77	FCR	1945	100	---
T-78	FCR	1999	5,000	UU
T-81	FFR	1936	5,079	---
T-82	FCR	2004	20,081	---
T-83	FCR	1938	20,039	---
T-84	FCR	1953	10,120	---
T-85	IFR	1954	10,120	---
T-88	EFR	1987	20,120	Kb
T-89	EFR	1948	20,120	---
T-96	FCR	1940	990	---
T-97	FCR	1940	990	---
T-98	FCR	1940	990	---

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-99	FCR	1940	1,008	---
T-101	FCR	1922	54,990	---
T-102	FCR	1922	55,236	---
T-103	EFR	1995	50,000	Kb
T-104	FCR	1923	55,500	---
T-105	FCR	1923	64,310	---
T-107	FCR	1923	55,140	---
T-110	FCR	1928	55,628	---
T-111	FCR	1936	55,755	---
T-114	FCR	1923	54,720	---
T-115	FCR	1923	54,601	---
T-116	FCR	1923	55,050	---
T-117	FCR	1923	55,000	---
T-118	FCR	1944	54,813	---
T-120	IFR	1949	80,419	---
T-123	EFR	1949	80,377	---
T-124	EFR	1959	54,432	---
T-125	EFR	1953	55,960	---
T-126	EFR	1953	55,960	---
T-128	EFR	1959	81,216	---
T-129	FCR	1937	2,546	---
T-142	FCR	1982	2,000	see notes[iv]
T-143	FCR	1982	2,000	see notes[iv]
T-145	FCR	1950	241	---
T-162	FCR	1951	2,050	---

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-165	HOR	1923	1,120	---
T-166	HOR	1923	1,120	---
T-167	FCR	1940	1,120	---
T-168	FCR	1940	1,331	---
T-170	FCR	1950	644	---
T-171	FCR	1950	644	---
T-173	HOR	1945	420	---
T-175	FCR	1940	5,128	---
T-176	FCR	1940	5,128	---
T-180	FCR	1959	300	---
T-188	FCR	1981	5,060	Ka
T-190	HOR	1940	158	---
T-199	FCR	1957	1,893	---
T-200	FCR	1936	2,180	---
T-201	HOR	2004	500	---
T-217	HOR	1964	52	---
T-219	FCR	1967	56,000	---
T-226	FCR	1936	273	---
T-228	FCR	1936	273	---
T-240	FCR	1953	3,036	---
T-241	FCR	1953	2,775	---
T-242	FCR	1953	2,688	---
T-243	FCR	1953	3,279	---
T-244	FCR	1953	2,088	---
T-245	IFR	1953	3,132	---

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-246	IFR	1953	3,107	---
T-262	FCR	1938	5,061	---
T-263	FCR	1938	5,061	---
T-264	FCR	1938	5,061	---
T-265	FCR	1938	5,061	---
T-270	FCR	1941	9,384	---
T-271	FCR	1941	9,240	---
T-272	FCR	1986	1,000	see notes[iii]
T-273	FCR	1986	1,000	see notes[iii]
T-274	FCR	1986	1,000	see notes[iii]
T-306	FCR	1952	133	---
T-310	FCR	1950	992	---
T-311	FCR	1950	54	---
T-312	FCR	1950	54	---
T-313	FCR	1950	54	---
T-314	FCR	1950	52	---
T-315	FCR	1950	52	---
T-319	FCR	1950	286	---
T-320	FCR	1950	286	---
T-321	FCR	1950	286	---
T-322	FCR	1950	286	---
T-323	FCR	1950	286	---
T-324	FCR	1992	286	see notes[v]
T-325	FCR	1950	286	---
T-326	FCR	1950	286	---

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-327	FCR	1950	286	---
T-328	FCR	1950	286	---
T-329	FCR	1950	286	---
T-330	FCR	1950	286	---
T-331	FCR	1950	286	---
T-332	FCR	1950	286	---
T-333	FCR	1950	286	---
T-335	FCR	1950	95	---
T-336	FCR	1950	95	---
T-337	FCR	1950	95	---
T-338	FCR	1950	95	---
T-339	FCR	1950	95	---
T-340	FCR	1961	504	---
T-348	FCR	1968	5,275	---
T-349	FCR	1968	5,279	---
T-350	FCR	1954	1,382	---
T-351	FCR	1954	1,382	---
T-352	FCR	1954	1,382	---
T-353	FCR	1954	1,382	---
T-354	FCR	1954	1,386	---
T-355	FCR	1959	1,006	---
T-356	FCR	1961	285	---
T-360	IFR	1957	15,120	---
T-361	IFR	1957	15,120	---
T-368	FCR	1966	10,120	---

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-371	IFR	1959	10,120	---
T-382	FCR	2000	5,000	UU see notes[iii]
T-383	FCR	2000	5,000	UU see notes[iii]
T-384	FCR	1999	3,060	UU
T-385	FCR	1999	3,060	UU
T-386	FCR	1999	3,060	UU see notes[iii]
T-387	FCR	1999	3,060	UU see notes[iii]
T-410	FCR	circa-1945	80,760	---
T-411	FCR	circa-1945	80,760	---
T-412	FCR	circa-1945	80,760	---
T-413	FCR	circa-1945	80,760	---
T-414	FCR	circa-1945	80,760	---
T-432	FCR	1978	2,025	see notes[iv]
T-520	FCR	1950	55,000	---
T-521	EFR	1950	55,000	---
T-524	FCR	1951	55,000	---
T-525	EFR	1951	55,000	---
T-530	FCR	1951	55,000	---
T-532	IFR	1981	32,784	Ka
T-538	FCR	1989	24	see notes[vi]
T-539	FCR	1989	24	see notes[vi]

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-540	HOR	1987	242	---
T-544	FCR	1991	5,250	see notes[iii]
T-548	FCR	1993	100,000	see notes[iii]
T-549	FCR	1994	143	see notes[vi]
T-550	HOR	1985	48	see notes[vi]
T-551	HOR	1994	24	see notes[vi]
T-552	HOR	1996	242	see notes[vi]
T-553	FCR	1999	1,500	see notes[iii]
T-570	EFR	1959	125,000	---
T-600	HOR	1994	48	see notes[vi]
T-601	HOR	1994	24	see notes[vi]
T-602	HOR	1994	24	see notes[vi]
T-603	HOR	1995	24	see notes[vi]
T-604	HOR	1994	13	see notes[vi]
T-605	HOR	1996	13	see notes[vi]
T-606	HOR	1996	13	see notes[vi]
T-607	HOR	1990	36	see notes[vi]
T-608	HOR	1987	190	see notes[vi]
T-609	HOR	1995	143	see notes[vi]
T-610	FCR	1980	8	see notes[ii]
T-611	FCR	1995	190	see notes[vi]
T-612	FCR	1995	71	see notes[vi]
T-613	HOR	2000	75	see notes[vi]
T-616	FCR	2000	48	see notes[vi]
T-618	FCR	2001	24	see notes[vi]

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-619	HOR	2001	48	see notes[vi]
T-620	HOR	2001	24	see notes[vi]
T-621	HOR	2001	13	see notes[vi]
T-622	HOR	2001	24	see notes[vi]

NSPS Regulation Notes

ii. Pursuant to 40 C.F.R. 60, Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*, Tank T-610 is not an affected source because it is smaller than 40,000 gallons.

iii. Pursuant to 40 C.F.R. 60, Subpart Kb- *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tanks T-24, T-113, T-272 through T-274, T-382 through T-387, T-544, T-548, and T-553 are exempt from the control requirements of Subpart Kb by §60.112b(a) because they store a liquid with a maximum true vapor pressure less than 5.2 kPa (0.75 psia) (see Appendix B).

iv. Pursuant to 40 C.F.R. 60, Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*, T-142, T-143, T-188 and T-432 are not affected facilities because they do not store volatile organic liquids (10.3 kPa) (see Appendix A).

v. Pursuant to 40 C.F.R. 60, Subpart Kb-*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tank T-324 is not an affected source under §60.110(a) because it does not contain a VOL (see Appendix B).

vi. Pursuant to 40 C.F.R. 60, Subpart Kb-*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tank's T-538, T-539, T-549 to T-552, T-600 to T-609, T-611, T-612, T-613, T-616, T-618, T-619, T-620, T-621, and T-622 are not affected sources because they are smaller than 75 m^3.

All other tanks, which are not listed above except tanks T-7, T-88, T-103, and T-532, are not subject to 40 C.F.R. 60, Subparts K, Ka, or Kb. The NSPS requirements for tanks T-88, T-103, and T-532 are outlined in the Specific Conditions.

All tanks have been classified as a Group I or Group II storage vessel in accordance with the provisions of 40 C.F.R. 63, Subpart CC-*National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*. Subpart CC is outlined in the Plantwide Conditions of this permit.

Specific Conditions

120. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with an annual emissions inventory, throughput limits, maximum vapor pressure restrictions, New Source Performance Standards, 40 C.F.R., Part 60, Subparts Ka and Kb (as applicable) and 40 CFR Part 63 Subpart CC (as applicable). [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/day	tpy
856	VOC	13,651.3*	6908.6

***This short-term limit includes short-term emissions from the Tier II tanks (SN-858).**

121. The facility shall store only products with a maximum vapor pressure equal to or less than the vapor pressure listed for each tank in the following table. [§19.501 of Regulation 19 and 40 C.F.R. § 70.6]

SN	Maximum Vapor Pressure
PAL	---
T-3	14.7^{D}
T-4	14.7^{D}
T-7	11.1^{FR}
T-11	14.7^{D}
T-12	14.7^{D}
T-14	14.7^{D}
T-15	14.7^{D}
T-16	14.7^{D}
T-17	14.7^{D}
T-18	14.7^{D}
T-19	0.75^{NC}
T-20	scheduled for removal, 2004
T-21	scheduled for removal, 2004
T-22	14.7^{D}
T-23	14.7^{D}

SN	Maximum Vapor Pressure
T-24	0.75 [NC]
T-25	14.7[D]
T-27	14.7[D]
T-36	11.1 [FR]
T-39	14.7[D]
T-40	14.7[D]
T-41	14.7[D]
T-46	14.7[D]
T-48	14.7[D]
T-49	14.7[D]
T-50	14.7[D]
T-51	14.7[D]
T-55	14.7[D]
T-56	14.7[D]
T-57	14.7[D]
T-58	14.7[D]
T-59	0.75[NC]
T-60	14.7[D]
T-61	11.1 [FR]
T-62	11.1 [FR]
T-63	14.7[D]
T-64	11.1 [FR]
T-65	11.1 [FR]
T-70	14.7[D]
T-71	14.7[D]
T-72	14.7[D]
T-73	14.7[D]
T-74	14.7[D]
T-76	14.7[D]

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Maximum Vapor Pressure
T-77	14.7^{D}
T-78	14.7^{D}
T-81	14.7^{D}
T-82	0.75^{NC}
T-83	14.7^{D}
T-84	14.7^{D}
T-85	11.1^{FR}
T-88	11.1^{FR}
T-89	11.1^{FR}
T-96	14.7^{D}
T-97	14.7^{D}
T-98	14.7^{D}
T-99	14.7^{D}
T-101	14.7^{D}
T-102	14.7^{D}
T-103	11.1^{FR}
T-104	14.7^{D}
T-105	14.7^{D}
T-107	14.7^{D}
T-110	14.7^{D}
T-111	14.7^{D}
T-114	14.7^{D}
T-115	14.7^{D}
T-116	14.7^{D}
T-117	14.7^{D}
T-118	14.7^{D}
T-120	11.1^{FR}
T-123	11.1^{FR}
T-124	11.1^{FR}

SN	Maximum Vapor Pressure
T-125	11.1 [FR]
T-126	11.1 [FR]
T-128	11.1 [FR]
T-129	14.7[D]
T-142	1.5[NC]
T-143	1.5[NC]
T-145	14.7[D]
T-162	14.7[D]
T-165	14.7[D]
T-166	14.7[D]
T-167	14.7[D]
T-168	14.7[D]
T-170	14.7[D]
T-171	14.7[D]
T-173	14.7[D]
T-175	14.7[D]
T-176	14.7[D]
T-180	14.7[D]
T-188	1.5[NC]
T-190	14.7[D]
T-199	14.7[D]
T-200	14.7[D]
T-201	14.7[C]
T-217	14.7[D]
T-219	14.7[D]
T-226	14.7[D]
T-228	14.7[D]
T-240	14.7[D]
T-241	14.7[D]

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Maximum Vapor Pressure
T-242	14.7[D]
T-243	14.7[D]
T-244	14.7[D]
T-245	11.1 [FR]
T-246	11.1 [FR]
T-262	14.7[D]
T-263	14.7[D]
T-264	14.7[D]
T-265	14.7[D]
T-270	14.7[D]
T-271	14.7[D]
T-272	0.75 [NC]
T-273	0.75 [NC]
T-274	0.75 [NC]
T-306	14.7[D]
T-310	14.7[D]
T-311	14.7[D]
T-312	14.7[D]
T-313	14.7[D]
T-314	14.7[D]
T-315	14.7[D]
T-319	14.7[D]
T-320	14.7[D]
T-321	14.7[D]
T-322	14.7[D]
T-323	14.7[D]
T-324	4.0 [NC]
T-325	14.7[D]
T-326	14.7[D]

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Maximum Vapor Pressure
T-327	14.7[D]
T-328	14.7[D]
T-329	14.7[D]
T-330	14.7[D]
T-331	14.7[D]
T-332	14.7[D]
T-333	14.7[D]
T-335	14.7[D]
T-336	14.7[D]
T-337	14.7[D]
T-338	14.7[D]
T-339	14.7[D]
T-340	14.7[D]
T-348	14.7[D]
T-349	14.7[D]
T-350	14.7[D]
T-351	14.7[D]
T-352	14.7[D]
T-353	14.7[D]
T-354	14.7[D]
T-355	14.7[D]
T-356	14.7[D]
T-360	11.1 [FR]
T-361	11.1 [FR]
T-368	14.7[D]
T-371	11.1 [FR]
T-382	0.75 [NC]
T-383	0.75 [NC]
T-384	0.75 [NC]

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

SN	Maximum Vapor Pressure
T-385	0.75 [NC]
T-386	0.75 [NC]
T-387	0.75 [NC]
T-410	14.7[D]
T-411	14.7[D]
T-412	14.7[D]
T-413	14.7[D]
T-414	14.7[D]
T-432	1.5[NC]
T-520	14.7[D]
T-521	14.7[D]
T-524	14.7[D]
T-525	14.7[D]
T-530	14.7[D]
T-532	11.1 [FR]
T-538	14.7[C]
T-539	14.7[C]
T-540	14.7[C]
T-544	0.75 [NC]
T-548	0.75 [NC]
T-549	14.7[C]
T-550	14.7[C]
T-551	14.7[C]
T-552	14.7[C]
T-553	0.75 [NC]
T-570	14.7[D]
T-600	14.7[C]
T-601	14.7[C]
T-602	14.7[C]

SN	Maximum Vapor Pressure
T-603	14.7^C
T-604	14.7^C
T-605	14.7^C
T-606	14.7^C
T-607	14.7^C
T-608	14.7^C
T-609	14.7^C
T-610	14.7^C
T-611	14.7^C
T-612	14.7^C
T-613	14.7^C
T-616	14.7^C
T-618	14.7^C
T-619	14.7^C
T-620	14.7^C
T-621	14.7^C
T-622	14.7^C

14.7^D No limit or restriction on v.p. - the construction (**D**)ate is prior to the NSPS date. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.

14.7^C No limit or restriction on v.p. - capacity of tank is below the NSPS applicability (**C**)apacity of 19,800 gals for Kb or 40,000 gals for K & Ka. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.

14.7^V No limit or restriction on v.p. - the product stored does not meet the definition of a (**V**)OL under Kb. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.

14.7^{P}	No limit or restriction on v.p. - the product does not meet the definition of a (**P**)etroleum liquid under Ka. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
x^{NC}	V. P. restricted or limited - (**N**)o (**C**)ontrols required; v.p. of product is below the limit that requires controls : 0.75 psia (5.2 kPa) for Kb (for tanks > 40,000 gal.); 4.0 psia (27.6 kPa) for Kb (for tanks with capacities between 20,000 and 40,000 gallons); or 1.5 psia (10.3 kPa) for K & Ka. See 40 C.F.R. §60.112b(a) and 60.112a(a).
x^{FR}	V. P. restricted or limited - v.p. of the product cannot exceed 11.1 psia (76.6 kPa) based on using a (**F**)loating (**R**)oof as the control standard as required by the NSPS and/or MACT standard.

122. Solely for purposes of demonstrating compliance with the Tank PAL emission limits, the facility shall not exceed a total refinery crude feed rate of 100,000 barrels per day and a total of 36.6 MM bbls per consecutive twelve-month period. This limit is solely to demonstrate compliance with the emission limits in Specific Condition # 120 and does not establish any production rate, design capacity or other limitation. [§19.705 of Regulation 19 and 40 C.F.R. §70.6]

123. The facility shall maintain records of the total refinery crude feed rate to the facility on a daily basis and on a twelve-month rolling basis, both updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

124. The facility shall conduct an annual inventory of emissions of the pollutants listed in Specific Condition #120. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), beginning in year 2003, and shall be submitted to the Department at the following address no later than August 1 of each year. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

Arkansas Department of Environmental Quality
Air Division
Attn: Compliance Inspector Supervisor
Post Office Box 8913
Little Rock, AR 72219

125. Under the terms of 40 CFR, Part 60, Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*, tanks T-108, 142, 143, 188, and 432 do not store a petroleum liquid with a true vapor pressure of 10.3 kPa (1.5 psia) or greater; and therefore are exempt from control requirements of Subpart Ka pursuant to 60.112a(a) (see Appendix A). Therefore, any petroleum liquid stored in these tanks shall have a vapor pressure less than 10.3 kPa (1.5 psia). Pursuant to 60.115a(a), the facility must maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period. [19.304 of Regulation 19 and 40 CFR 60.112a]

126. Tank T-532 is an affected facility under the terms of 40 CFR 60, Subpart Ka- *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984*. However, in accordance with 40 C.F.R., Part 63, Subpart CC- *National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries*, §63.640(n), the facility is only required to comply with the provisions of Subpart CC (see Appendix A). [19.304 of Regulation 19 and 40 CFR 63.640(n)]

127. Under the terms of 40 CFR Part 60 Subpart Kb-*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tanks T-7, T-88 and T-103 are affected facilities. The tanks are subject to the Subpart Kb requirements, which are summarized below (for the full regulation, see Appendix B). [§19.304 of Regulation 19, and 40 CFR §60.110b]

    a. Pursuant to §60.112b(a), tanks T-7, T-88 and T-103 have been equipped with external floating roofs as described in §60.112b(a)(2).

    b. Pursuant to §60.112b(a)(2)(i)(A), tanks T-7, T-88, and T-103 have a mechanical shoe seal. Except as provided in §60.113b(b)(4), the seals shall completely cover the annular space between the edge of the floating roof and the tank wall.

    c. Pursuant to §60.112b(a)(2)(i)(B), the secondary seals shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed by §60.113b(b)(4).

    d. Pursuant to §60.112b(a)(2)(ii), except for automatic bleeder vents and rim space vents, each opening in the floating roofs provides a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are gasketed. Each emergency roof drain is provided with a slotted membrane fabric cover that covers at least 90 percent of the opening of the area.

e. Pursuant to §60.112b(a)(2)(ii), the roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

f. Pursuant to §60.113b, tanks T-7, T-88 and T-103 shall meet the testing requirements of §60.113b(b).

g. Pursuant to §60.113b(b)(1), the facility has determined and will continue to determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel as prescribed by §60.113b(b)(1)(i).

h. Pursuant to §60.113b(b)(1)(i), measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed at least once every 5 years after the date of the initial fill.

i. Pursuant to §60.113b(b)(1)(ii), measurements of gaps between the tank wall and the secondary seal shall be performed at least once per year after the date of the initial fill.

j. Pursuant to §60.113b(b)(1)(iii), if these sources cease to store a VOL for a period of one year or more, subsequent introduction of VOL into the vessels shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

k. Pursuant to §60.113b(b)(2), the facility shall determine gap widths and areas in the primary and secondary seals individually by the procedures outlined in (i), (ii), and (iii) as follows:

   i. Pursuant to §60.113b(b)(2)(i), the facility shall measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

   ii. Pursuant to §60.113b(b)(2)(ii), the facility shall measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

   iii. Pursuant to §60.113b(b)(2)(iii), the total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

l. Pursuant to §60.113b(b)(3), the facility shall add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4).

m. Pursuant to §60.113b(b)(4), the facility shall make necessary repairs or empty the storage vessels within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4)(i) and (ii).

n. Pursuant to §60.113b(b)(4)(i), the accumulated area of gaps between the tank wall and the mechanical shoe or liquid mounted primary seal shall not exceed 212 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

o. Pursuant to §60.113b(b)(4)(i)(A), one end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

p. Pursuant to §60.113b(b)(4)(i)(B), there are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

q. Pursuant to § 60.113b(b)(4)(ii), the secondary seal is to meet the requirements of the following:

    i. Pursuant to § 60.113b(b)(4)(ii)(A), the secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in (b)(2)(iii).

    ii. Pursuant to § 60.113b(b)(4)(ii)(B), the accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

    iii. Pursuant to § 60.113b(b)(4)(ii)(C), there are to be no holes, tears, or other openings in the seal or seal fabric.

r. Pursuant to § 60.113b(b)(4)(iii), if a failure that is detected during inspections required by paragraph (b)(1), of § 60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required by § 60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

s. Pursuant to § 60.113b(b)(5), the facility shall notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present. The Department has exercised its authority to grant permission for the 30-day notification period to be shortened to 5 days as indicated by Plantwide Condition #14 (FF) and (GG).

t. Pursuant to § 60.113b(b)(6), the facility shall visibly inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

u. Pursuant to § 60.113b(b)(6)(i), if an external floating roof has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the facility shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

v. Pursuant to § 60.113b(b)(6)(ii), for all inspections required by (b)(6) , the facility shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the facility could not have known about the inspection 30 days in advance of refilling the tank, the facility should notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received at least 7 days prior to the refilling. The Department has exercised its authority to grant permission for the 30-day and 7-day notification periods to be shortened to 5 days as indicated by Plantwide Condition #14 (FF) and (GG).

w. Pursuant to § 60.115b(b), the facility shall keep records of tanks T-7, T-88 and T-103 as specified in § 60.115b(b)(3). The facility shall keep copies of all reports and records required by this section for at least 2 years.

x. Pursuant to § 60.115b(1), the facility has or shall furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(a)(2), (b)(3), and (b)(4).

y. Pursuant to § 60.115b(b)(2), within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), the facility shall furnish the Administrator with a report that contains:

   i. The date of measurement.

   ii. The raw data obtained in the measurement.

   iii. The calculations described in § 60.113b(b)(2) and (b)(3).

z. Pursuant to § 60.115b(b)(3), the facility shall keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

   i. The date of measurement.

ii. The raw data obtained in the measurement.

iii. The calculations described in § 60.113b(b)(2) and (b)(3).

aa. Pursuant to § 60.115b(b)(4), after each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in (b)(2) and the date the vessel was emptied or the repairs made and date of repair.

bb. Pursuant to § 60.116b(a), the facility shall keep copies of all records of tanks T-7, T-88 and T-103 as required by § 60.116b for at least 2 years. As an exception, the record required by § 60.116b(b) shall be kept for the lives of the sources.

cc. Pursuant to § 60.116b(b), the facility shall keep readily accessible records showing the dimensions of each vessel and an analysis showing the capacity of each vessel.

dd. Pursuant to § 60.116b(c), the facility shall maintain for each tank a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

ee. Pursuant to § 60.116b(e), the facility may determine the maximum true vapor pressure as described in § 60.116b(e)(1), (e)(2) and (e)(3).

128. Tanks T-19, T-24, T-59, T-272 through T-274, T-382 through T-387, T-544, T-548, and T-553 are exempted from the control requirements of Subpart Kb pursuant to 40 C.F.R. 60.112b(a) because they have capacities greater than 151 m^3 and store a liquid with a maximum true vapor pressure less than 5.2 kPa (0.75 psia). Therefore, any volatile organic liquid stored in these tanks shall have a vapor pressure less than 5.2 kPa (0.75 psia). These tanks are also subject to the following subpart Kb requirements, which are summarized below (for the full regulation, see Appendix B). [§19.304 of Regulation 19 and 40 CFR §60.112b(a)]

a. The facility shall as specified in § 60.116b(a) keep the records as required by § 60.116b(b) for the lives of the facilities.

b. In accordance with § 60.116b(b), the facility shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

c. In accordance with § 60.116b(d), the facility shall notify the Department within 30 days when the maximum true vapor pressure exceeds 5.2 kPa (0.75 psia).

d. Pursuant to § 60.116b(e), the facility may determine the maximum true vapor pressure as described in § 60.116b(e)(1), (e)(2) and (e)(3).

129. Tank T-324 does not store a volatile organic liquid with a vapor pressure of 15.0 kPa (4.0 psia); and, therefore is exempt from the control requirements of Subpart Kb. As such, any volatile organic liquid stored in this tank shall have a vapor pressure less than 15.0 kPa (4.0 psia). This tank is also subject to the Subpart Kb requirements, which are summarized below (for the full regulation, see Appendix B). [§19.304 of Regulation 19 and 40 CFR §60.110b(c)]

   a. The facility shall as specified in § 60.116b(a) keep the records as required by § 60.116b(b) for the lives of the facilities.

   b. In accordance with § 60.116b(b), the facility shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

   c. In accordance with § 60.116b(d), the facility shall notify the Department within 30 days when the maximum true vapor pressure exceeds 15 kPa (4.0 psia).

   d. Pursuant to § 60.116b(e), the facility may determine the maximum true vapor pressure as described in § 60.116b(e)(1), (e)(2) and (e)(3).

130. Under the terms of 40 CFR Part 60 Subpart UU- *Standards of Performance for Asphalt Processing and Asphalt Roofing* Manufacture, tanks T-24, T-78,T-382, T-383, T-384, T-385, T-386, and T-387 are affected facilities. As such, in accordance with 60.472(c), the tank(s) shall not exhaust gases with an opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being cleared. [§19.304 of Regulation 19, and 40 CFR §60.470]

131. Records shall be kept onsite of any activity related to construction, reconstruction, or modification of any of the tanks listed in this section. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-857 and 860

Tier II Heaters

Source Description

This source consists of the new refinery heaters which were installed as part of the Tier II low-sulfur fuels project completed in 2003/2004. Each of these heaters is being permitted to burn desulfurized refinery fuel gas. SN-857 is the Naptha Splitter Reboiler Heater, and SN-860 is the ULSD Hydrotreater Heater. SN-857 is rated at 53.4 MMBtu/hr, and SN-860 is rated at 43.6 Btu/hr.

Regulations

The Tier II Heaters are subject to 40 CFR Part 60 Subpart J – *Standards of Performance for Petroleum Refineries* as fuel gas combustion devices.

Specific Conditions

132. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [§19.501 of Regulation 19 *et seq*., and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	Tpy
857	Naptha Splitter Reboiler Heater		
	PM_{10}	1.4	5.3
	SO_2	2.1	7.9
	VOC	1.0	3.8
	CO	5.2	19.3
	NO_X	2.2	8.2
860	ULSD Hydrotreater Heater		
	PM_{10}	1.2	4.3
	SO_2	1.7	6.5
	VOC	0.8	3.1

	CO	4.2	15.8
	NO_X	1.8	6.7

133. The facility shall not exceed 5% opacity from the sources in this section burning pipeline quality natural gas or desulfurized refinery fuel gas. Compliance with this limit shall be demonstrated by burning only pipeline quality natural gas or refinery fuel gas in the Tier II Heaters. If the H_2S concentration of the refinery fuel gas exceeds 1000 mg/dscm (0.435 gr/dscf), then the facility shall comply with Plantwide Condition #12. [§18.501 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

134. Natural gas or desulfurized refinery fuel gas (as defined by Plantwide Condition #8(a)) shall be the only fuels combusted in the Tier II heaters (SN-857). [§§19.304 and 19.705 of Regulation 19, 40 CFR §60.404(a)(1), and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

135. The maximum heat duty for SN-857 shall not exceed a total heat capacity of 469,066 MMBtu during any consecutive 12-month period. The maximum heat duty for SN-860 shall not exceed a total heat capacity of 382,982 MMBtu during any consecutive 12-month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]

136. The permittee shall maintain monthly records of the Btu throughput of the Tier II Heaters (SN-857 and SN-860). These records shall be maintained on-site and shall be made available to Department personnel upon request. These records shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19 and 40 CFR Part 52 Subpart E]

137. The Tier II Heaters (SN-857 and SN-860) are affected facilities under the provisions of 40 C.F.R. 60, Subpart J-*Standards of Performance for Petroleum Refineries*. They are defined in the subpart as fuel gas combustion devices. These sources are all subject to the Subpart J requirements, which are summarized in Specific Condition # 134 and below (for the full regulation, see Appendix C): [§19.304 of Regulation 19 and 40 CFR §60.100]

   l. The facility shall install, calibrate, maintain and operate a continuous monitoring system for SN-857 and SN-860 in accordance with the provisions of § 60.105 outlined below. [§60.105(a)(4)]

      i. The CEM system shall monitor the concentration (dry basis) of H_2S in fuel gases prior to being burned in any fuel gas combustion device.

      ii. The span value for this instrument shall be 425 mg/dscm H_2S.

      iii. All fuel gas combustion devices having a common source of fuel gas may be monitored at only one location if monitoring at this location accurately represents the concentration of H_2S in the fuel gas burned at each source.

   m. Pursuant to § 60.105(e), for purposes of reports under § 60.7(c), periods of excess emissions for sulfur dioxide from fuel gas combustion shall be determined and reported as required by § 60.105(e)(3).

   n. Pursuant to § 60.106(a), in conducting the performance tests required in § 60.8, the facility shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

   o. Pursuant to § 60.106(e), the owner or operator shall determine compliance with the H_2S standard in § 60.104(a)(1) as follows: Method 11 (or other approved method) shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

p. Pursuant to § 60.106(f), the facility shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in § 60.104(a)(2) by § 60.106(f)(1), (2), and (3).

q. Pursuant to § 60.106(f)(1), Method 6 (or other approved method) shall be used to determine the SO_2 concentration. The concentration in mg/dscm (lb/dscf) obtained by Method 6 (or other approved method) is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m^2 (54 ft^2) or at a point no closer to the walls than 1.00 m (39 in.) if the cross-sectional area is 5.00 m^2 or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases. The sampling point for Method 4 (or other approved method) shall be adjacent to the sampling point for Method 6 (or other approved method). The sampling time for each sample shall be equal to the time it takes for two Method 6 (or other approved method) samples. The moisture content from this sample shall be used to correct the corresponding Method 6 (or other approved method) samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 (or other approved method) shall be used following the procedures of paragraph (f)(2) of this section.

r. Pursuant to § 60.106(f)(2), Method 15 (or other approved method) shall be used to determine the reduced sulfur and H_2S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 (or other approved method) in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 (or other approved method) shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

s. Pursuant to § 60.106(f)(3), the oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 (or other approved method). The samples shall be taken simultaneously with the SO_2, reduced sulfur and H_2S, or moisture samples. The SO_2, reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(3) of this section.

SN-858

Tier II Fugitives and Tanks VOC Bubble

Source Description

This source includes all fugitive emissions associated with the Tier II low-sulfur fuels project, as well as those tanks which were modified as part of the Tier II project. These sources are bubbled together in order to simplify the tracking of actual emissions increases associated with the Tier II project. The following existing refinery tanks have been included in this emissions bubble.

Tank Number	Storage Capacity (barrels)	Tank Contents	Year Installed or Last Modified	Tank Type*
T-113	50,000	FCC Gasoline	2003	EFR
T-247	5,130	FCC Heavy Naphtha	2003	IFR
T-372	10,120	FCC Heavy Naphtha	2003	IFR
T-54	15,090	#2 Diesel	1922	FDR
T-108	55,447	#2 Diesel	1982	IFR
T-109	55,367	#2 Diesel	1982	IFR
T-119	55,140	#2 Diesel	1940	FCR
T-121	80,440	#2 Diesel	1949	FCR
T-122	80,440	#2 Diesel	1953	FCR

* Key: EFR=External Floating Roof, IFR=Internal Floating Roof, FDR=Fixed Dome Roof, FCR=Fixed Cone Roof

Tanks T-113, T-247, and T-372 have been converted from diesel storage to the current usage, and have been retrofitted with either internal or external floating roofs. The remaining tanks included in this bubble continue to store diesel fuel, but are experiencing a throughput increase associated with the Tier II project.

Regulations

All fugitive equipment leak sources associated with the Tier II project are subject to 40 CFR Part 60 Subpart GGG – *Standards of Performance for Equipment Leaks of VOC from Petroleum Refineries*.

Tanks T-108 and T-109 are subject to 40 CFR Part 60 Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*. These tanks are affected sources as described in §60.110a, but they are exempt from the control requirements of this subpart by §60.112a(a) because they do not store a petroleum liquid with a true vapor pressure greater than 1.5 psia.

Tanks T-113, T-247, and T-372 are subject to 40 CFR Part 60 Subpart Kb – *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) For Which Construction, Reconstruction, or Modification commenced after July 23, 1984*. These three tanks have all been reconstructed and retrofitted with floating roofs as part of the Tier II project at the facility.

Specific Conditions

138. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [§19.501 of Regulation 19 *et seq*., and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
858	VOC	*	363.8

*** Short term emissions from tier II fugitives are subject to the short-term limit for all facility fugitives found in Specific Condition #114. Short-term emissions from tier II tanks are subject to the short term limit for the facility tanks bubble found in Specific Condition #120.**

139. The facility shall conduct an annual emission inventory to demonstrate compliance with the emission limits of Specific Condition #138. The fugitive emissions included in SN-858 shall be calculated by the methods and equations used in AP-42, Chapter 5.1 (5^{th} Edition or later version) or *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017 (November 1995 or later version), or other ADEQ-approved method. The tank emissions shall be calculated by the use of the methods outlined in AP-42 Chapter 7, or other ADEQ-approved method. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. 70.6]

140. Records for the emission inventory required in Specific Condition #139 shall be maintained on an annual basis. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), beginning in year 2004, and shall be submitted to the Department at the following address no later than August 1 of each year. [§19.705 of Regulation 19 and 40 C.F.R. Part 52, Subpart E]

Arkansas Department of Environmental Quality
Air Division
Attn: Compliance Inspector Supervisor
Post Office Box 8913
Little Rock, AR 72219

141. All sources of fugitive VOC from equipment leaks, including each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service and associated with the Tier II clean fuels project, are affected facilities under the terms of 40 CFR Part 60 Subpart GGG – *Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries*. For the purposes of recordkeeping and reporting only, compressors are also considered affected facilities (see Appendix F). The facility is subject to the Subpart GGG requirements, which are summarized below. [§19.304 of Regulation 19, and 40 CFR §60.590(a)(1) and (3)]

a. Pursuant to § 60.592(a), the facility shall comply with the standards for specific equipment found in §§ 60.482-1 to 60.482-10 of 40 C.F.R. 60, Subpart VV.

b. Pursuant to § 60.592(b), an owner or operator may elect to comply with the alternative standards for valves in §§ 60.483-1 and 60.483-2.

c. Pursuant to § 60.592(c), an owner or operator may apply to the Administrator for a permit modification for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of § 60.484.

d. Pursuant to § 60.592(d), each owner or operator subject to the provisions of this subpart shall comply with the testing provisions of § 60.485 except as provided in § 60.593.

e. Pursuant to § 60.592(e), each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping and reporting provisions of §§ 60.486 and 60.487.

f. Pursuant to § 60.593(a), each owner or operator subject to the provisions of this subpart may comply with the allowable exceptions to the provisions of subpart VV.

142. All sources of VOC equipment leaks associated with the Tier II clean fuels project are subject to 40 CFR Part 60 Subpart VV-*Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry* as referenced by Subpart GGG (see Appendix G). These sources are subject to the requirements of Subpart VV which are summarized below. [§19.304 of Regulation 19, and 40 CFR §§60.590 and 60.592]

a. Pursuant to § 60.482-1(a), the facility shall demonstrate compliance with the requirements of §§ 60.482-1 to 60.482-10 for all equipment within 180 days of initial startup.

b. Pursuant to § 60.482-1(b), compliance with §§ 60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485.

c. Pursuant to § 60.482-1(c)(1), the facility may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in § 60.484. *(Note: This will require a permit modification.)*

d. Pursuant to § 60.482-1(c)(2), if the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, or 60.482-10, the facility shall comply with the requirements of that determination. *(Note: This will require a permit modification.)*

e. Pursuant to § 60.482-3(a), the compressors in hydrogen service are not subject to this subpart as per the exemption of § 60.593(b)(1).

f. Pursuant to § 60.482-4, the facility has no pressure relief devices in gas/vapor service and is not subject to this section.

g. Pursuant to § 60.482-6(a)(1), each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1(c).

h. Pursuant to § 60.482-6(a)(2), the cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

i. Pursuant to § 60.482-6(b), each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

j. Pursuant to § 60.482-6(c), when a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times.

k. Pursuant to § 60.482-7, the facility shall comply with the requirements for valves in gas/vapor service or in light liquid service.

l. Pursuant to § 60.482-10, the facility shall comply with the requirements for closed vent systems and control devices.

m. Pursuant to § 60.483-2, the facility has elected to comply with the alternative work practice specified in paragraphs (b)(3) of this section.

n. Pursuant to § 60.483-2(2), the facility has notified the Administrator before implementing these alternative work practices, as specified in § 60.487(d).

o. Pursuant to § 60.483-2(b)(1), the facility has initially complied with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7.

p. Pursuant to § 60.483-2(b)(3), after 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

q. Pursuant to § 60.483-2(b)(4), if the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7 but can again elect to use this section.

r. Pursuant to § 60.485(a), in conducting the performance tests required in § 60.8, the facility shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

s. Pursuant to § 60.485(b), the facility shall determine compliance with the standards in §§ 60.482 and 60.483 as follows:

   i. Method 21 (or other approved method) shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 (or other approved method). The following calibration gases shall be used:

      1. Zero air (less than 10 ppm of hydrocarbon in air); and

      2. A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

t. Pursuant to § 60.485(c), the facility shall determine compliance with the no detectable emission standards in §§ 60.482-2(e), and 60.482-3(i) as follows:

   i. The requirements of paragraph (b) shall apply.

   ii. Method 21 (or other approved method) shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

iii. Pursuant to § 60.485(f), samples used in conjunction with paragraphs (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

u. Pursuant to § 60.486(a)(1), the facility shall comply with the recordkeeping requirements of this section.

v. Pursuant to § 60.486(a)(2), an owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

w. Pursuant to § 60.486(b), when each leak is detected as specified in §§ 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply:

i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

ii. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7(c) and no leak has been detected during those 2 months.

iii. The identification on equipment except on a valve, may be removed after it has been repaired.

x. Pursuant to § 60.486(k), the provisions of § 60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

y. Pursuant to § 60.487(a), the facility shall submit semiannual reports to the Administrator beginning six months after the initial start up date.

z. Pursuant to § 60.487(b), the initial semiannual report to the Administrator shall include the following information:

i. Process unit identification.

1. Number of valves subject to the requirements of § 60.482-7, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7(f).

2. Number of pumps subject to the requirements of § 60.482-2, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2(e) and those pumps complying with § 60.482-2(f).

3. Number of compressors subject to the requirements of § 60.482-3, excluding those compressors designated for no detectable emissions

under the provisions of § 60.482-3(i) and those compressors complying with § 60.482-3(h).

aa. Pursuant to § 60.487(c), all semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486:

i. Process unit identification.

ii. For each month during the semiannual reporting period,

1. Number of valves for which leaks were detected as described in § 60.482(7)(b) or § 60.483-2,

2. Number of valves for which leaks were not repaired as required in § 60.482-7(d)(1),

3. Number of pumps for which leaks were detected as described in § 60.482-2(b) and (d)(6)(i),

4. Number of pumps for which leaks were not repaired as required in § 60.482-2(c)(1) and (d)(6)(ii),

5. Number of compressors for which leaks were detected as described in § 60.482-3(f),

6. Number of compressors for which leaks were not repaired as required in § 60.482-3(g)(1), and

7. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

iii. Dates of process unit shutdowns which occurred within the semiannual reporting period.

iv. Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

bb. Pursuant to § 60.487(d), the facility has elected to comply with the provisions of § 60.483-2 and has notified the Administrator of the alternative standard selected 90 days before implementing the provision. If the facility decides to comply with the provisions of § 60.483-1, the facility shall notify the Administrator 90 days in advance before implementing the provisions.

cc. Pursuant to § 60.487(e), the facility shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that the facility must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

143. In order to demonstrate compliance with Subparts GGG and VV the facility shall maintain a log of the following for all equipment leak sources associated with the Tier II clean fuels project. [§19.304 of Regulation 19, and 40 C.F.R. 60, Subparts GGG and VV]

a. Compliance with testing provisions as required by § 60.592(d).

b. Any exemptions for compressors considered to be in hydrogen service.

c. Any exemptions for equipment that is in vacuum service as provided by § 60.482-1(d).

d. Monthly monitoring results of § 60.482-2(a)(1).

e. Weekly visual inspection checks of liquids dripping of § 60.482-2(a)(2).

f. Record of instrument reading of § 60.482-2(b)(1).

g. Record of leaks from pump seal in § 60.482-2(b)(2).

h. Attempts to repair leak within 15 days as provided by § 60.482-2(c)(1).

i. Attempts to repair leak within 5 days as provided by § 60.482-2(c)(2).

j. Records of exemption for each pump equipped with a dual mechanical seal system as provided by § 60.482-2(d).

k. Records of exemption for any pump designated for no detectable emission as provided by § 60.482-2(e).

l. Records of exemption for any pump equipped with a closed vent system as provided by § 60.482-2(f).

m. Records that each sampling connection system is equipped with a closed purge system or closed vent system in §60.482-5(a) and (b) or qualifies for the exemptions.

n. All in-situ sampling systems that are exempt in § 60.482-5(c).

o. Record of monitoring of potential leaks within 5 days as required by § 60.482-8(a).

p. Record of leaks detected in § 60.482-8(b).

q. Attempts to repair leak within 15 days as provided by § 60.482-8(c)(1).

r. Attempts to repair leak within 5 days as provided by § 60.482-8(c)(2).

s. Record of delay of repair of equipment as allowed in § 60.482-9(a) or (b).

t. Record of delay of repair of equipment as allowed in § 60.482-9(c).

u. Record of delay of repair of equipment as allowed in § 60.482-9(d).

v. Delays of repair beyond a process unit shutdown as allowed in § 60.482-9(e).

w. Record of the percent of valves leaking as required in § 60.483-2(5) and (6).

x. Records of the tests and results of § 60.485(d).

y. Results of § 60.485.

z. Records of § 60.485(g).

aa. Information required by § 60.486(c) for leaks.

bb. Information required by § 60.486(d) for the design requirements for closed vent system/control device.

cc. Information required by § 60.486(e) for the equipment.

dd. Information required by § 60.486(f) for the valves.

ee. Information required by § 60.486(g) for the valves.

ff. Information required by § 60.486(h).

gg. Requirements to show that equipment is not in VOC service as provided by §60.486(j).

144. Under the terms of 40 CFR, Part 60, Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*, tanks T-108 and 109 do not store a petroleum liquid with a true vapor pressure of 10.3 kPa (1.5 psia) or greater; and therefore are exempt from control requirements of Subpart Ka pursuant to 60.112a(a) (see Appendix A). Therefore, any petroleum liquid stored in these tanks shall have a vapor pressure less than 10.3 kPa (1.5 psia). Pursuant to 60.115a(a), the facility must maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period. [19.304 of Regulation 19 and 40 CFR 60.112a]

145. Under the terms of 40 CFR Part 60 Subpart Kb-*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tanks T-113, T-247 and T-372 are affected facilities. The tanks are subject to the Subpart Kb requirements, which are summarized below (for the full regulation, see Appendix B). [§19.304 of Regulation 19, and 40 CFR §60.110b]

a. Pursuant to §60.112b(a), tank T-113 has been equipped with external floating roofs as described in §60.112b(a)(2).

b. Pursuant to §60.112b(a), Tanks T-247 and T-372 have been equipped with internal floating roofs as described in §60.112b(a)(1).

c. Pursuant to §60.112b(a)(2)(i)(A), tank T-113 has a mechanical shoe seal. Except as provided in §60.113b(b)(4), the seals shall completely cover the annular space between the edge of the floating roof and the tank wall.

d. Pursuant to §60.112b(a)(2)(i)(B), the secondary seals shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed by §60.113b(b)(4).

e. Pursuant to §60.112b(a)(2)(ii), except for automatic bleeder vents and rim space vents, each opening in the floating roofs provides a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are gasketed. Each emergency roof drain is provided with a slotted membrane fabric cover that covers at least 90 percent of the opening of the area.

f. Pursuant to §60.112b(a)(2)(ii), the roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

g. Pursuant to §60.113b, tanks T-113, T-247 and T-372 shall meet the testing requirements of §60.113b(b).

h. Pursuant to §60.113b(b)(1), the facility has determined and will continue to determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel as prescribed by §60.113b(b)(1)(i).

i. Pursuant to §60.113b(b)(1)(i), measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed at least once every 5 years after the date of the initial fill.

j. Pursuant to §60.113b(b)(1)(ii), measurements of gaps between the tank wall and the secondary seal shall be performed at least once per year after the date of the initial fill.

k. Pursuant to §60.113b(b)(1)(iii), if these sources cease to store a VOL for a period of one year or more, subsequent introduction of VOL into the vessels shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

l. Pursuant to §60.113b(b)(2), the facility shall determine gap widths and areas in the primary and secondary seals individually by the procedures outlined in (i), (ii), and (iii) as follows:

   i. Pursuant to §60.113b(b)(2)(i), the facility shall measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

   ii. Pursuant to §60.113b(b)(2)(ii), the facility shall measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

   iii. Pursuant to §60.113b(b)(2)(iii), the total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

m. Pursuant to §60.113b(b)(3), the facility shall add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4).

n. Pursuant to §60.113b(b)(4), the facility shall make necessary repairs or empty the storage vessels within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4)(i) and (ii).

o. Pursuant to §60.113b(b)(4)(i), the accumulated area of gaps between the tank wall and the mechanical shoe or liquid mounted primary seal shall not exceed 212 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

p. Pursuant to §60.113b(b)(4)(i)(A), one end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

q. Pursuant to §60.113b(b)(4)(i)(B), there are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

r. Pursuant to § 60.113b(b)(4)(ii), the secondary seal is to meet the requirements of the following:

   i. Pursuant to § 60.113b(b)(4)(ii)(A), the secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in (b)(2)(iii).

ii. Pursuant to § 60.113b(b)(4)(ii)(B), the accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

iii. Pursuant to § 60.113b(b)(4)(ii)(C), there are to be no holes, tears, or other openings in the seal or seal fabric.

s. Pursuant to § 60.113b(b)(4)(iii), if a failure that is detected during inspections required by paragraph (b)(1), of § 60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required by § 60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

t. Pursuant to § 60.113b(b)(5), the facility shall notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present. The Department has exercised its authority to grant permission for the 30-day notification period to be shortened to 5 days as indicated by Plantwide Condition #14 (FF) and (GG).

u. Pursuant to § 60.113b(b)(6), the facility shall visibly inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

v. Pursuant to § 60.113b(b)(6)(i), if an external floating roof has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the facility shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

w. Pursuant to § 60.113b(b)(6)(ii), for all inspections required by (b)(6) , the facility shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the facility could not have known about the inspection 30 days in advance of refilling the tank, the facility should notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received at least 7 days prior to the refilling. The Department has exercised its authority to grant permission for the 30-day and 7-day notification periods to be shortened to 5 days as indicated by Plantwide Condition #14 (FF) and (GG).

x. Pursuant to § 60.115b(b), the facility shall keep records of tanks T-113, T-247 and T-372 as specified in § 60.115b(b)(3). The facility shall keep copies of all reports and records required by this section for at least 2 years.

y. Pursuant to § 60.115b(1), the facility has or shall furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(a)(2), (b)(3), and (b)(4).

z. Pursuant to § 60.115b(b)(2), within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), the facility shall furnish the Administrator with a report that contains:

   i. The date of measurement.

   ii. The raw data obtained in the measurement.

   iii. The calculations described in § 60.113b(b)(2) and (b)(3).

aa. Pursuant to § 60.115b(b)(3), the facility shall keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

   i. The date of measurement.

   ii. The raw data obtained in the measurement.

   iii. The calculations described in § 60.113b(b)(2) and (b)(3).

bb. Pursuant to § 60.115b(b)(4), after each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in (b)(2) and the date the vessel was emptied or the repairs made and date of repair.

cc. Pursuant to § 60.116b(a), the facility shall keep copies of all records of tanks T-113, T-247 and T-372 as required by § 60.116b for at least 2 years. As an exception, the record required by § 60.116b(b) shall be kept for the lives of the sources.

dd. Pursuant to § 60.116b(b), the facility shall keep readily accessible records showing the dimensions of each vessel and an analysis showing the capacity of each vessel.

ee. Pursuant to § 60.116b(c), the facility shall maintain for each tank a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

ff. Pursuant to § 60.116b(e), the facility may determine the maximum true vapor pressure as described in § 60.116b(e)(1), (e)(2) and (e)(3).

SN-859

No. 8 Cooling Tower (Replaces No. 1 CT)

Source Description

This new cooling tower has been constructed as part of the Tier II clean fuels project in order to replace the former Number 1 cooling tower. This new tower will handle the increased cooling water flows associated with this project. Cooling water flow through the No. 8 tower is expected to be 14,500 gpm. The No. 8 cooling tower utilizes drift eliminators to achieve a drift of 0.008%.

Specific Conditions

146. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [§19.501 of Regulation 19 *et seq*., and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
859	No. 8 Cooling Tower		
	VOC	5.3	22.9
	PM_{10}	2.9	12.8

147. The total amount of water circulated at the #8 cooling tower shall be limited to 7,642,080 gallons per consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311, and 40 C.F.R. § 70.6]

148. Records of the water circulated at the #8 cooling tower shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

Plantwide Applicability Limit (PAL) for Other Air Emissions

In order to demonstrate compliance with Regulation 18, § 18.801, the facility will operate under a Plantwide Applicability Limit (PAL) for other air emissions. The Department has reviewed these emissions and determined that compliance with these emission limitations will constitute compliance with the terms of §18.801 of Regulation 18 for the sources identified in this permit. This PAL is meant to allow the facility flexibility in operation and production while at the same time limiting the total amount of air emissions from the facility.

Specific Conditions

149. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by an annual emissions inventory and compliance with the feed rate, physical and operational limits in this Permit. [§18.801 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

Description	Pollutant*	Allowable Emission Rate TPY
Plantwide Applicability Limit[1]	Benzene	67.9
	Biphenyl	9.5
	1,3 Butadiene	5.1
	Carbon Disulfide	4.4
	Carbonyl Sulfide	4.5
	Cresol (mixed isomers)	14.0
	Cumene	10.2
	Diethanolamine	4.4
	Ethyl benzene	43.6
	Hexane	314.5
	Naphthalene	6.6
	Phenol	9.8
	Toluene	148.7
	2,2,4 Trimethylpentane	56.2
	Xylene (mixed isomers)	341.8
	Ammonia	62.1
	Chlorine	26.7
	Hydrogen Chloride	48.6
	Sulfuric Acid	88.3
	Hydrogen Sulfide	364.3
	Perchloroethylene (tetrachloroethylene)	7.1
	Formaldehyde	4.9
	Particulate matter	884.3

*** Other air contaminants may be emitted from the facility in very small quantities, which would be difficult to measure and report. No significant levels of unlisted air contaminants are allowable under this permit.**

1 The PAL does not include volatile organic compound (VOC) air emissions that are not hazardous air pollutants (HAP), as defined in 42 U.S.C. § 7412(b). The emissions of these non-HAP organic pollutants are captured and regulated by the VOC emission limits for the individual sources in this Permit.

150. The facility shall conduct an annual inventory of emissions of the pollutants listed in Specific Condition #149. The emissions inventory shall be calculated using methods relied upon in establishing the emission limits in Specific Condition #149. The facility may use different methodologies than those relied upon in establishing the limits; however, any change in a methodology shall be submitted to the Department and approved in advance of submission of the annual emission inventory. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), beginning in year 2003, and shall be submitted to the Department at the following address no later than August 1 of each year. If an annual emissions inventory is requested by the Department before August 1, the permittee shall have until August 1 to submit the requested information. This condition does not apply to emissions inventories requested by the Department pursuant to §19.705(c) and 40 CFR §51.321. [§18.1004 of Regulation 18, and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

    Arkansas Department of Environmental Quality
    Air Division
    Attn: Compliance Inspector Supervisor
    Post Office Box 8913
    Little Rock, AR 72219

151. If the annual emissions inventory demonstrates that the permittee has exceeded any PAL limit, it shall not be considered a violation of the permit provided that the exceedance is due to either a change in a published emission factor upon which permittee relied in setting the permitted limit, new emissions factors or the development of other emissions data (including site specific test data), which could affect the estimated emission rates. [§18.1004 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

ALTERNATE OPERATING SCENARIOS

FCCU PORTABLE AIR COMPRESSORS

During periods of startup, shutdown and/or malfunction, or for purposes of conducting scheduled or emergency maintenance on the fluid catalytic cracking unit when the electric air compressor is not operating, Lion Oil may utilize portable, diesel-fired air compressors.

Specific Conditions

1. The permittee shall not operate the portable compressors for more than 1,560,000 horsepower-hours on an annual basis. [§19.501 of Regulation 19, et seq., and 40 C.F.R., Part 52, Subpart E]

2. Lion Oil will record the hours of operation of the air compressors, on a twelve-month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

Section V: PLANT WIDE CONDITIONS

1. The permittee will notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation No. 19 §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation No.19 §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) New Equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start-up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee will submit the compliance test results to the Department within thirty (30) days after completing the testing. [Regulation No.19 §19.702 and/or Regulation No. 18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. The permittee must provide: [Regulation No.19 §19.702 and/or Regulation No.18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

    a. Sampling ports adequate for applicable test methods

    b. Safe sampling platforms

    c. Safe access to sampling platforms

    d. Utilities for sampling and testing equipment.

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee will maintain the equipment in good condition at all times. [Regulation No.19 §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation No. 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

7. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. [Regulation No. 26 §26.701 and 40 CFR 70.6(a)(4)]

8. For purposes of this permit: [§19.705 of regulation 19, A.C.A. 8-4-203, as referenced by 8-4-304 and 8-4-311, and 40 CFR §70.6]

    a. Desulfurized refinery fuel gas is gas meeting the 40 C.F.R., Part 60, Subpart J, limits of 0.10 gr/dscf H_2S (or measure SO_2 in accordance with the Subpart). [40 CFR §60.104(a)(1)]

    b. The allowable limit for refinery fuel gas combusted in SNs 816 - 820 is gas meeting a limit of 0.15 mole % of H_2S.

9. Pipeline quality natural gas is that which meets the tariff requirements of any major transmission company. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. § 70.6]

10. The facility shall analyze the Btu content of the desulfurized refinery fuel gas on a monthly basis. [§19.705 of Regulation 19, and 40. C.F.R., Part 52, Subpart E]

11. Records of the Btu content of the desulfurized refinery gas shall be maintained on a monthly basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40. C.F.R., Part 52, Subpart E]

12. During those times in which the H_2S content of the refinery fuel gas combusted on-site exceeds 1500 ppmvd, the facility shall conduct an opacity observation for those sources which are permitted to combust desulfurized refinery fuel gas. These observations shall be conducted by someone who is familiar with the visible emissions from these sources. Any sources which generate visible emissions during these periods shall be considered to be in violation of the 5% opacity standard for that source. Records of these observations shall be maintained on-site, and shall be made available to the Department upon request These records shall indicate the date and time of the observation, the name of the person making the observation, whether or not any visible emissions are detected, and a list of any sources (by SN) for which visible emissions were noted. [§18.501 of Regulation 18 and A.C.A. § 8-4-203 as referenced by § 8-4-304 and § 8-4-311]

13. The facility is subject to 40 CFR Part 61 Subpart FF – *National Emission Standards for Benzene Waste Operations* because it is a petroleum refinery (see Appendix E). [§19.304 of Regulation 19 and 40 CFR §61.340(a)]

    a. The facility has identified itself as having total annual benzene emissions of less than 10 Mg/yr. The facility shall follow any applicable requirements of § 61.342(a).

    b. The facility shall keep the records required by § 61.356(a) and (b).

    c. The facility shall follow the reporting requirements of § 61.357(c).

14. The facility is subject to the provisions of 40 CFR Part 63 Subpart CC-*National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*, which are summarized below (for the full regulation, see Appendix I).

    a. For the purpose of this subpart, the affected source shall comprise all emission points, in combination, listed in § 63.640(c)(1) through (c)(7) that are located at a single refinery plant site. *Note: (c)(6) does not apply.*

        i. All miscellaneous process vents from petroleum refining process units meeting the criteria in § 63.640 (a);

        ii. All storage vessels associated with petroleum refining process units meeting the criteria in § 63.640(a);

        iii. All wastewater streams and treatment operations associated with petroleum refining process units meeting the criteria in § 63.640(a);

        iv. All equipment leaks from petroleum refining process units meeting the criteria in § 63.640(a);

        v. All gasoline loading racks classified under Standard Industrial Classification code 2911 meeting the criteria in § 63.640(a);

        vi. All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery meeting the criteria in § 63.640(a).

    b. Pursuant to § 63.640(d), the affected source does not include the emission points listed in paragraphs (d)(1) through (d)(5).

        i. Stormwater from segregated stormwater sewers;

        ii. Spills;

        iii. Any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in § 63.641 of this subpart, for less than 300 hours during the calendar year.

iv. Catalytic cracking unit and catalytic reformer catalyst regeneration vents, and sulfur plant vents.

v. Emission points routed to a fuel gas system, as defined in § 63.641 of this subpart. No testing, monitoring recordkeeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.

c. The owner or operator shall keep a log of the storage vessels in § 63.640(e)(1) and (e)(2) that are subject to Subpart CC.

d. The owner or operator shall keep a log of the miscellaneous process vents from distillation units in § 63.640(f)(1) through (f)(5) that are subject to Subpart CC.

e. The facility shall keep a log of the processes specified in paragraphs § 63.646(g)(1) through (g)(7) that are exempt from Subpart CC.

f. Sources subject to Subpart CC shall achieve compliance with the subpart by the dates specified in § 63.640(h).

g. Sources that are added, reconstructed, have additions, or are otherwise modified shall achieve compliance in accordance with § 63.640(i), (j), and (k).

h. If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, or gasoline loading rack that meets the criteria in § 63.640 (c)(1) through (c)(7) is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emission point(s) (as defined in § 63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to § 63.640 (i) or (j), the requirements in § 63.640 (l)(1) through (l)(3) shall apply. The facility shall keep a log to show that it has complied with the provisions of this section.

i. If a change that does not meet the criteria in § 63.640(l) is made to a petroleum refining process unit subject to this subpart, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in § 63.641), then the owner or operator shall comply with the requirements of this subpart for existing sources for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1. A compliance schedule for the change shall be submitted to the Administrator in accordance with § 63.640(m)(1) through (3).

j. The following shall apply to the facility for the overlap of subpart CC with other regulations for storage vessels in § 63.640(n)(1) through (7).

Overlap with Existing Federal Regulations - Storage Vessels

Overlap with Existing Federal Regulations - Storage Vessels				
Existing Regulation	**Source**	**Group**	**Comply with**	**Comments**
40 C.F.R. 60, Subpart Kb	Existing	Group 1 Group 2	40 C.F.R. 60, Subpart Kb	
40 C.F.R. 60, Subpart Kb	New	Group 1	40 C.F.R. 63, Subpart CC	
40 C.F.R. 60, Subpart Kb (see comment)	New	Group 2	40 C.F.R. 60, Subpart Kb	If source is subject to control requirements in Subpart Kb, comply with Kb instead of CC.
40 C.F.R. 60, Subpart Kb (see comment)	New	Group 2	40 C.F.R. 63, Subpart CC	If source is not required to apply controls by Subpart Kb, comply with CC instead of Kb.
40 C.F.R. 60, Subpart K or Ka	New and Existing	Group 1	40 C.F.R. 63, Subpart CC	
40 C.F.R. 60, Subpart K or Ka	New and Existing	Group 2	40 C.F.R. 60, Subpart K or Ka	If source is subject to control requirements in Subparts K or Ka, comply with K or Ka instead of CC.
40 C.F.R. 60, Subpart K or Ka	New and Existing	Group 2	40 C.F.R. 63, Subpart CC	If source is not required to apply controls by Subparts K or Ka, comply with CC instead of K or Ka.

k. The following shall apply to the facility for the overlap of subpart CC with other regulations for wastewater in § 63.640(o)(1) and (2).

Overlap with Existing Federal Regulations - Wastewater				
Existing Regulation	**Source**	**Group**	**Comply with**	**Comments**
40 C.F.R. 60, Subpart QQQ	New and Existing	Group 1	40 C.F.R. 63, Subpart CC	
40 C.F.R. 61, Subpart FF	New and Existing	Group 1	40 C.F.R. 61, Subpart FF	
40 C.F.R. 63, Subpart G	New and Existing	Group 1 Group 2	40 C.F.R. 63, Subpart G, §§ 63.133-63.137, 63.140	Applies to equipment used in storage and conveyance of wastewater streams.
			40 C.F.R. 61, Subpart FF, and 40 C.F.R. 63, Subpart G, §§ 63.138, 63.139	Applies to treatment and control of wastewater streams.
			40 C.F.R. 63, Subpart G, §§ 63.143-63.148	Applies to monitoring and inspections of equipment and recordkeeping and reporting requirements.

l. After the compliance dates specified in § 63.640(h) equipment leaks that are also subject to the provisions of 40 C.F.R. 60 and 61 are required to comply only with the provisions of this subpart.

m. The facility shall refer to Table 6 of Subpart CC in accordance with § 63.642(c) for in order to reference specific provisions of Subpart A of Part 63 that apply and those that do not apply.

n. Pursuant to § 63.642(d), initial performance tests and initial compliance determinations shall be required only as specified in this subpart. A log showing compliance with §§ 63.642(d)(1) through (4) shall be kept.

o. Pursuant to §63.642(e), each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in this subpart. All applicable records shall be maintained in such a manner that they can be readily accessed. Records for the most recent 2 years shall be retained onsite at the source or shall be accessible from a central location by computer. The remaining 3 years of records may be retained offsite. Records may be maintained in hard copy or computer- readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

p. Pursuant to §63.642(f), all reports required under this subpart shall be sent to the Administrator at the addresses listed in § 63.13 of subpart A of this part. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.

q. Pursuant to §63.642(h), the owner or operator of a new source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the equation in paragraph (g) of this section.

r. Pursuant to §63.642(i), the owner or operator of an existing source shall demonstrate compliance with the emission standard in §63.642(g) by following the procedures specified in §63.642(k) for all emission points, or by following the emissions averaging compliance approach specified in §63.642(l) for specified emission points and the procedures specified in §63.642(k) for all other emission points within the source. The facility shall keep a log to demonstrate compliance with this provision.

s. Pursuant to §63.642(j), the owner or operator of a new source shall demonstrate compliance with the emission standard in §63.642(h) only by following the procedures in §63.642(k). The owner or operator of a new source may not use the emissions averaging compliance approach. The facility shall keep a log to demonstrate compliance with this provision.

t. The owner or operator of a Group 1 miscellaneous process vent as defined in § 63.641 shall comply with the requirements of either § 63.643(a)(1) or (a)(2). A log shall be kept to demonstrate compliance with these provisions.

u. The facility shall keep a log to demonstrate compliance with the provisions of § 63.644(a) for Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in § 63.643(a).

v. The facility shall keep a log to demonstrate how it has complied with § 63.644(c) which requires the owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with § 63.644(a) to follow additional constraints outlined in § 63.644(c).

w. Pursuant to § 63.644(d), the owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of this section. In order to establish the range, the information required in §63.654(f)(1)(3) shall be submitted in the Notification of Compliance Status report.

x. Pursuant to § 63.644(e) Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under paragraphs (a) and (b) of this section. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in §63.654(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.

y. The facility shall comply with the test measures and procedures for miscellaneous process vents in § 63.645.

z. Pursuant to § 63.645(h), the owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. A log of these calculations and supporting assumptions shall be kept to demonstrate compliance with § 63.645.

aa. The facility shall keep a log to demonstrate that the compliance determination for § 63.645(i) has been meet.

bb. The facility shall comply with the storage vessel provisions of § 63.646. Notices of Compliance Status Report shall be submitted to the Administrator as required by this section.

cc. Pursuant to§ 63.646(e), when complying with the inspection requirements of § 63.120 of subpart G of this part, owners and operators of storage vessels at existing sources subject to this subpart are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals.

dd. Pursuant to§ 63.646(f), the paragraphs (f)(1), (f)(2), and (f)(3) of this section apply to Group 1 storage vessels at existing sources:

   i. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

ii. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

iii. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

ee. Pursuant to§ 63.646(g), failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

ff. The provisions of 40 CFR 63.646(l) provide state permitting agencies with the authority to waive or modify the notification requirements of 40 CFR §§ 63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii). The notification requirements of these sections are hereby modified as follows: Lion Oil shall provide notice, as required herein, by facsimile transmittal five (5) business days prior to the scheduled event in lieu of providing 30 days prior written notice to the Department. This written notice may be submitted electronically to the local district air inspector and the ADEQ Air Division Enforcement Branch Technical Assistance Manager.

gg. The provisions of 40 CFR §63.654(h)(2)(C)(ii) provide state permitting agencies with the authority to waive or modify the notification requirements of 40 CFR §63.120(b)(1) or §63.120(b)(2) of Subpart G of part 63. The notification requirements of these sections are hereby modified as follows: Lion Oil shall provide notice, as required herein, by facsimile transmittal five (5) business days prior to the scheduled event in lieu of providing 30 days prior written notice to the Department. This written notice may be submitted electronically to the local district air inspector and the ADEQ Air Division Enforcement Branch Technical Assistance Manager.

hh. The facility shall comply with the wastewater provisions of § 63.647. The facility shall maintain a log to demonstrate that it has complied with the requirements of this section.

ii. The facility shall comply with the equipment leak standards of § 63.648. Portions of this section overlap with the requirements already listed for Subpart VV in the Fugitive Emissions (SN- 854) section of this permit. The facility may combine the requirements of that section with this section and keep all necessary reports in one log. In any case, the facility shall keep a log to demonstrate compliance with this section.

jj. Pursuant to § 63.648(h), each owner or operator of a source subject to the provisions of this subpart must maintain all records for a minimum of 5 years.

kk. The facility shall comply with the gasoline loading rack provisions of § 63.650(a). The facility shall keep a log to demonstrate that all requirements of this section have been met.

ll. The facility shall keep in a log, methods used and affected equipment for any of the emissions averaging provisions that are used in § 63.652. The facility shall also follow the requirements for § 65.653. Records for monitoring, recordkeeping, and implementation plans shall also be kept in the same log.

mm. The facility shall comply with the provisions of § 63.654(a) and keep a log of how it has complied with those provisions.

nn. The facility shall comply with the provisions of § 63.654(b) and keep a log of how it has complied with those provisions.

oo. The facility shall comply with the provisions of § 63.654(d)(1) through (6) and keep a log of how it has complied with those provisions.

pp. Pursuant to § 63.654(e), the facility shall submit the reports listed in paragraphs (e)(1) through (e)(3) except as provided in paragraph (h)(5) of this section, and shall keep records as described in paragraph (i) of this section.

i. A Notification of Compliance Status report as described in paragraph (f) of this section.

ii. Periodic Reports as described in paragraph (g) of this section.

iii. Other reports as described in paragraph (h) of this section.

qq. The facility shall keep a log to show that it has complied with § 63.654(f)(1) through (6).

rr. The facility shall keep a log to show that it has complied with the requirements of § 63.654(g)(1) through (g)(8).

ss. The facility shall keep a log demonstrating that it has complied with the submittal requirements of § 63.654(h).

tt. The facility shall keep a log of the records required by § 63.654(i).

uu. All other information required to be reported under paragraphs § 63.654(a) through (h) shall be retained for 5 years.

vv. Compliance demonstrations begin on the first of the next calendar month following the beginning of the permit requirement. For those sources not subject to a rolling average requirement in the permits preceding AR-868-R0, rolling average requirements do not begin until twelve months after the issuance of this permit. Although on-going compliance with annual limits will be demonstrated with twelve-month rolling averages, violation of annual limits can only occur once per calendar year.

15. This facility is subject to the federal regulations identified herein at the time of permit issuance. The source(s) affected by these regulations must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in

this permit or its appendices. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit. [§19.304 of Regulation 19 and 40 CFR Part 52 Subpart E]

Title VI Provisions

16. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.

    b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.

    c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.

    d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

17. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.

    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.

    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.

    d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC-like appliance" as defined at §82.152.)

    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

18. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

19. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

    a. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant.

20. The permittee can switch from any ozone-depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G, "Significant New Alternatives Policy Program".

Permit Shield

21. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements, as of the date of permit issuance, included in and specifically identified in Table 7 - Applicable Regulations of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated February 24, 2003.

SN	Regulation	Description
Facility	Ark. Pollution Control and Ecology Commission Regulation 19	Compilation of Regulation of the Arkansas State Implementation Plan for Air Pollution Control
Facility	Ark. Pollution Control and Ecology Commission Regulation 26	Regulations of the Arkansas Operating Air Permit Program
SN-828, SN-850	40 CFR Part 60, Subpart Dc	Standards of Performance for Small Industrial-Commercial Steam Generating Units

SN	Regulation	Description
SN-803, SN-804, SN-805, SN-808, SN-811, SN-818-820, SN-822,SN-823,SN-824, SN-824,SN-828,SN-829, SN-830, SN-832, SN-842, SN-843,SN-844, SN-850	40 CFR Part 60, Subpart J	Standards of Performance for Petroleum Refineries
T-532, T-108, T-109	40 CFR Part 60 Subpart Ka	Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification commenced after May18, 1978 and prior to July 23, 1984
T-7, T-88, T-103, T-24, T-113, T-272, T-273, T-274, T-382 through T-387, T-544, T-548, T-553	40 CFR Part 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Storage Vessels) for which Construction, Reconstruction, or Modification commenced after July 23, 1984
T-382, T-383	40 CFR Part 60, Subpart UU	Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture
Equipment Leaks*	40 CFR Part 60 Subpart VV	Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry
#4 Crude Unit, #6 Hydrotreater/Isomerization Unit, #12 Distillate Hydrotreater, #17 Sulfur Recovery Plant*, and #19 PMA Plant	40 CFR Part 60, Subpart GGG	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
Facility	40 CFR Part 61 Subpart FF	National Emission Standard for Benzene Waste Operations

SN	Regulation	Description
Facility*, T-36, T-61, T-62, T-64, T-65,T-66, T-67, T-85, T-89, T-120, T-123, T-124, T-125 T-126, T-128, T-245, T-246, T-360, T-361, T-371, T-532, T-536	40 CFR Part 63, Subpart CC	National Emission Standard for Hazardous Air Pollutants from Petroleum Refineries

***Equipment leak provisions apply only to those components that are subject to Subpart GGG (incorporating the provisions of Subpart VV) and 40 C.F.R. 63, Subpart CC.**

The permit specifically identifies the following as inapplicable based upon information submitted by the permittee in an application dated February 24, 2003.

Description of Regulation	Regulatory Citation	Affected Source	Basis for Determination
Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	40 C.F.R. 60 Subpart Db	SN-816 to SN-820	Units were installed before 1984.
Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	40 C.F.R. 60 Subpart Dc	SN-829 SN-828	Units were installed before 1989.
Standards of Performance for Petroleum Refineries	40 C.F.R. 60, Subpart J	SN-806, SN-809, SN-810, SN-812, SN-813, SN-814, SN-816 to SN-820, SN-825	Constructed prior to the effective dates of Subpart J.
Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.	40 C.F.R. 60, Subpart Ka	T-610 T-108, T-109, T-142, T-143, and T-432	Smaller than 40,000 gallons. Exempt from controls because these tanks store a petroleum liquid with a maximum true vapor pressure less than 10.3 kPa (1.5 psia).

Description of Regulation	Regulatory Citation	Affected Source	Basis for Determination
Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.	40 C.F.R. 60, Subpart Kb	T-24, T-113, T-272 to T-274, T-382-387, T-553, T-544, and T-548, T-553, T-324	Exempt because they store a liquid with a maximum true vapor pressure less than 5.2 kPa (.75 psia). Exempt because capacity greater than or equal to 75 m^3, but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa (4.0 psia).
		T-538, T-539, T-540, T-549 to T-552, T-600 to T-609, T-611, and T-612	Smaller than 40 m^3.
---	40 C.F.R. 60, Subpart K, Ka, and Kb	All tanks not previously identified	Constructed prior to June 11,1973; Constructed prior to May 19, 1978; Constructed prior to July 23, 1984 (as applicable); or do not exceed size requirements for the subparts.
Standards of Performance for Asphalt Roofing Manufacture	40 C.F.R. 60, Subpart UU	Blowing Stills (associated with SN-825)	Constructed prior to November 18, 1980.

Description of Regulation	Regulatory Citation	Affected Source	Basis for Determination
National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene	40 C.F.R. 61, Subpart J	Pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges and other connectors, product accumulator vessels, and control devices or systems	There are no affected facilities in benzene service (greater than 10% benzene by weight).
National Emission Standard for Benzene Emissions From Benzene Storage Vessels	40 C.F.R. 61, Subpart Y	Storage Vessels	None of the storage vessels contain benzene products.
National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	40 C.F.R. 63, Subpart Q	Cooling Tower	Cooling towers have not operated with chromium-based water treatment chemicals on or after September 8, 1994.

Consent Decree Requirements

The following conditions are required to be added to this permit by Paragraph 24 of the consent decree agreement reached between Lion Oil, the US EPA, and ADEQ. In many instances, these conditions are restatements of requirements which appear elsewhere in the Specific and/or Plantwide Conditions of this permit.

22. The following heaters and boilers should be identified as affected facilities and subject to and required to comply with all applicable requirements of the New Source Performance Standards, Subparts A and J: #6 Hydrotreater/Reboiler (SN-806), #9 Stabilizer Reboiler (SN-812), #11 Deasphalting Furnace (SN-814), #16 Asphalt Blowing Furnaces (SN-825), Asphalt Rack Steam Heater (SN-828), Steam Superheater Furnace (SN-829), Asphalt Hot Regenerate Furnace (SN-830), #12 Unit Stripper Reboiler Furnace (SN-843), and the Asphalt Hot Oil Heater (SN-850). Provided however that if there is a future revision of NSPS Subpart J which excludes either certain fuel gas combustion devices or fuel gas streams from NSPS Subpart J, then that exemption, as applicable, shall apply to the

foregoing heaters and boilers. [§19.304 of Regulation 19 and 40 CFR Part 60 Subparts A and J]

23. The permittee shall not burn fuel oil in any combustion unit except under the following circumstances. The permittee may only burn fuel oil at those sources where it is allowable by the Specific Conditions of this permit. [§19.304 of Regulation 19 and 40 CFR §60.11(d)]

    l. The permittee shall be permitted to burn torch oil in the FCCU regenerator during FCCU start-ups;

    m. During periods of natural gas curtailment where the permittee shall burn only LPG or low sulfur distillate (e.g. No. 2 oil at less than 0.5% sulfur by wt.).

24. The Sulfur Recovery Plant (SN-844) is subject to and required to comply with all applicable provisions of 40 CFR Part 60 (NSPS) Subparts A and J. [§19.304 of Regulation 19 and 40 CFR Part 60 Subparts A and J]

25. The permittee shall route all emissions from the sulfur recovery plant (SN-844) such that sulfur pit emissions to the atmosphere are either eliminated or are included and monitored as part of the applicable sulfur recovery plant tail gas emissions that meet the NSPS Subpart J limit for SO_2: a 12-hour rolling average of 250 ppmvd SO_2 corrected to 0% oxygen. [§19.304 of Regulation 19 and 40 CFR §60.104(a)(2)]

26. The permittee shall comply with the Preventive Maintenance and Operation Plan for the Sulfur Recovery Plant, including any modifications thereto, at all times, including periods of start up, shut down, and malfunction. [§19.304 of Regulation 19 and 40 CFR §60.11(d)]

27. The High and Low Pressure Flares (SN-822 and SN-823) are subject to and shall comply with all applicable requirements of 40 CFR Part 60 Subparts A and J. The following conditions apply to facility compliance with the Subpart J. [§19.304 of Regulation 19 and 40 CFR Part 60 Subparts A and J]

    l. For continuous or intermittent, routinely-generated refinery fuel gases that are combusted in the high or low pressure flare (SN-822 or SN-823), the permittee shall either take the flare that is associated with such a gas stream out of service, or comply with the emission limit of 40 CFR §60.104(a)(1).

    m. The combustion of gases generated by the start-up, shut-down, or malfunction of a refinery process unit or released to a flaring device as a result of relief valve leakage or other emergency malfunction are exempt from the requirement to comply with 40 CFR §60.104(a)(1).

    n. The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR §60.11(d) to minimize HC and AG flaring incidents (as defined below).

o. The permittee shall ensure that all continuous or intermittent, routinely-generated refinery fuel gases that are combusted in any flaring device are monitored by a CEM system as required by 40 CFR §60.105(a)(4) or with a parametric monitoring system approved by EPA as an alternative monitoring system under 40 CFR §60.13(i). The permittee shall comply with the reporting requirements of 40 CFR Part 60 Subpart J for all such flaring devices.

28. These definitions shall apply to the following requirements.

l. **AG Flaring Incident** shall mean the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas which results in the emission of sulfur dioxide equal to, or in excess of, 500 pounds in any 24-hour period in excess of the permitted limit; provided, however, that if 500 pounds or more of sulfur dioxide have been emitted in a 24-hour period and flaring continues into subsequent, contiguous, non-overlapping 24-hour periods, each period which results in emissions equal to, or in excess of 500 pounds of sulfur dioxide in excess of the permitted limit, then only one AG flaring incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of flaring within the AG flaring incident.

m. **Tail Gas Incident** shall mean the combustion of tail gas that either is: (i.) combusted in a flare and results in 500 pounds or more of SO_2 emissions in any 24-hour period, or (ii.) combusted in a thermal incinerator and results in excess emissions of 500 pounds or more of SO_2 emissions in any 24-hour period. Only those time periods which are in excess of an SO_2 concentration of 250 ppm (rolling 12-hour average) shall be used to determine the amount of excess SO_2 emissions from the incinerator. Lion Oil shall use engineering judgment and/or other monitoring data during periods in which the SO_2 CEM system has exceeded the range of the instrument or is out of service.

n. **Hydrocarbon (HC) Flaring Incident** shall mean continuous or intermittent hydrocarbon flaring, except for acid gas or sour water stripper gas, or tail gas, at a hydrocarbon flaring device that results in the emission of sulfur dioxide equal to or greater than 500 pounds in a 24-hour period; provided, however, that if 500 pounds or more of SO2 have been emitted in a 24-hour period and flaring continues into subsequent, contiguous, non-overlapping 24-hour periods, each period of which results in emissions equal to or in excess of 500 pounds of SO2, then only one HC flaring incident shall have occurred. Subsequent contiguous, non-overlapping periods are measured from the initial commencement of flaring within the HC flaring incident.

29. The permittee shall comply with the following requirements as they relate to AG flaring incidents, tail gas incidents, and HC flaring incidents. [§19.304 of Regulation 19 and 40 CFR §60.11(d)]

l. For tail gas incidents, the investigative and corrective action procedures shall be applied to TGU shutdowns, bypasses of a TGU, unscheduled shutdowns of a sulfur recovery plant, or other miscellaneous unscheduled sulfur recovery plant events which result in a tail gas incident.

m. The permittee shall investigate the root cause and all contributing causes of all AG flaring incidents, tail gas incidents, and HC flaring incidents. The permittee shall take reasonable steps to correct the conditions that have caused or contributed to such incidents, and to minimize such incidents. The permittee shall evaluate whether AG flaring incidents, tail gas incidents, and HC flaring incidents are due to malfunctions.

n. In response to any AG flaring incident, tail gas incident, or HC flaring incident, the permittee 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 the AG flaring incident, tail gas incident, or HC flaring incident.

30. The permittee is prohibited from using the emissions reductions that result from the installation and operation of the controls required by the consent decree (CIV. No. 03-1028) ("CD Emissions Reductions") for the purpose of emissions netting or emissions offsets, while still allowing the permittee to use a fraction of the CD emissions reductions if: (1) the emissions for which the permittee seeks to use the CD emissions reductions are modified or constructed for the purposes of compliance with Tier II gasoline or low-sulfur diesel requirements; and (2) the emissions from those modified or newly-constructed units are below the levels outlined in paragraph 27.C.ii of the consent decree prior to the commencement of operations of the emissions units for which the permittee seeks to use the CD emissions reductions.

l. **General Prohibition** – The permittee shall not generate or use any NOx, SO2, PM, VOC, or CO emissions reductions that result from any projects conducted or controls required pursuant to the consent decree as netting reductions or emissions offsets in any PSD, major non-attainment, and/or minor New Source Review (NSR) permit or permit proceeding.

m. **Exception to General Prohibition**:

i. Utilization of the exception set forth in paragraph 27.C.ii to the general prohibition against the generation or utilization of CD emissions reductions set forth in paragraph 27.B of the consent decree is subject to the following conditions:

1. Under no circumstances shall the permittee use CD emissions reductions for netting and/or offsets prior to the time that actual CD emissions reductions have occurred.

2. CD emissions reductions may only be used at the El Dorado refinery that generated them.

3. The CD emissions reductions provisions of the consent decree are for the purposes of the consent decree only and neither the permittee nor any other entity may use CD emissions reductions for any purpose, including in any subsequent permitting or enforcement proceeding, except as provided herein.

4. The permittee shall remain subject to all federal and state regulations applicable to the PSD, major non-attainment, and/or minor NSR permitting processes.

ii. Notwithstanding the general prohibition set fort in Paragraph 27.B of the consent decree, the permittee may use 10 tons per year of NOx, 10 tpy of PM, and 35 tpy of SO2 from the CD emissions reductions as credits or offsets in any PSD, major non-attainment, and/or minor NSR permit or permit proceeding occurring after the date of lodging of the consent decree (March 11, 2003), provided that the new or modified emissions unit: (1) is being constructed of modified for the purposes of compliance with Tier II gasoline or low-sulfur diesel requirements; and (1) has a federally enforceable permit that reflects:

1. For heaters and boilers, that next-generation ultra low-NO_x burners are installed and the limit is established pursuant to Paragraph 16.D of the consent decree.

2. For heaters and boilers, a limit of 0.10 grains of hydrogen sulfide per dry standard cubic foot (dscf) of fuel gas or an outlet concentration limit of 20 ppmvd SO_2 corrected to 0% oxygen both on a 3-hour rolling average.

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

4. For the FCCU, a limit of 20 ppmvd NOx or less corrected to 0% oxygen on a 365-day rolling average basis.

5. For the FCCU, a limit of 25 ppmvd SO2 corrected to 0% oxygen on a 365-day rolling average basis.

6. For SRP's, NSPS Subpart J emission limits.

31. None of the conditions of this permit are intended to prohibit the permittee from seeking to: (1) utilize or generate emissions credits or reductions from refinery units that are covered by the consent decree to the extent that the proposed credits or reductions represent the difference between the emissions limitations set forth in the consent decree for these refinery units and the more stringent emissions limitations that the permittee may elect to accept for those refinery units in a permitting process; or (2) utilize or generate or generate emission credits or reductions on refinery units that are not covered by the consent decree.

Additional Requirements

32. The permittee must prepare and implement a Startup, Shutdown, and Malfunction Plan (SSM). If the Department requests a review of the SSM, the permittee will make the SSM available for review. The permittee must keep a copy of the SSM at the source's location and retain all previous versions of the SSM plan for five years. [Regulation No. 19 §19.304 and 40 CFR 63.6(e)(3)]

33. No later than 6 months prior to the compliance date of April 11, 2005, the facility shall prepare and submit a permit application to the Department which incorporates the requirements of 40 CFR Part 63 Subpart UUU into this permit. [§19.304 of Regulation 19 and 40 CFR Part 63 Subpart UUU]

Section VI: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement is a significant activity even if this activity meets the criteria of §304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated February 21, 2003.

Table 9 - Insignificant Activities

Description	Category
Fire suppression systems, emissions from fire or emergency response equipment and training, including but not limited to, use of fire control equipment and pumps powered by internal combustion engines, equipment testing, and training.	A-13
Repair of electrical generators.	A-13
Equipment used for surface coating, painting, dipping, or spraying operations that do not emit any VOC or HAP.	A-9
Up to 93 storage tanks each of which is less than or equal to 250 gallons and stores a liquid having a true vapor pressure less than or equal to 3.5 psia (24.2 kPa).	A-2
Up to 34 fuel additive and treatment chemical storage tanks each of which is less than or equal to 10,000 gallons and stores a liquid having a true vapor pressure less than or equal to 0.5 psia (3.5 kPa).	A-3
Caustic storage tanks that contain no VOCs.	A-4
Natural gas or distillate oil fired fuel burning equipment used to regenerate the facility's amine and having a design firing rate less than 10 million Btu per hour.	A-1
Operation of the OCC Emergency Use Generator (with a maximum capacity of 100 kW fired with diesel fuel) and other Emergency use portable pumps, generators, compressors and boilers not otherwise specifically listed by name or application in this permit or insignificant activities list, provided that the units are less than 10,000,000 Btu/hr and used for back-up power generation during times when the primary source of power is unavailable to the facility.	A-1

Description	Category
Operation of Emergency Use fuel-fired compressors in lieu of the East Instrument Air Compressor, West Instrument Air Compressor, East Utility Air Compressor, West Utility Air Compressor, North ESVG Compressor, South ESVG Compressor and the CCR Air Compressor, provided that the operation of the fuel-fired equipment does not operate in conjunction with the facility's primary compressors.	A-12
Operation of Emergency Use portable pumps, generators, compressors and boilers not otherwise specifically listed by name or application in this permit or insignificant activities list that are used for emergency purposes provided that the units are less than 10,000,000 Btu/hr.	A-1
Asphalt Protective Coatings Baghouse (former SN-807)	A-13
Acid Fume Scrubbers (former SN-826 and SN-827)	A-13
Lime Silo Baghouse (former SN-845)	A-13

Pursuant to §26.304 of Regulation 26, the Department determined the emission units, operations, or activities contained in Regulation 19, Appendix A, Group B, to be insignificant activities. Activities included in this list are allowable under this permit and need not be specifically identified.

Facility: Lion Oil Co.
Permit No.: 868-AOP-R2
AFIN: 70-00016

Section VII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation No. 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq*.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq*.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq*.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute.[40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26), effective August 10, 2000]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation No. 26 §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.* (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation No. 26 §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit. [40 CFR 70.6(a)(3)(ii)(A) and Regulation No. 26 §26.701(C)(2)]

    a. The date, place as defined in this permit, and time of sampling or measurements;

    b. The date(s) analyses performed;

    c. The company or entity performing the analyses;

    d. The analytical techniques or methods used;

    e. The results of such analyses; and

    f. The operating conditions existing at the time of sampling or measurement.

6. The permittee must retain the records of all required monitoring data and support information for at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation No. 26 §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every 6 months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within 30 days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26 §26.2 must certify all required reports. The permittee will send the reports to the address below: [40 C.F.R. 70.6(a)(3)(iii)(A) and §26.701(C)(3)(a) of Regulation #26]

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor
   Post Office Box 8913
   Little Rock, AR 72219

8. The permittee will report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit. The permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include: [40 CFR 70.6(a)(3)(iii)(B), Regulation #26 §26.701(C)(3)(b), and Regulation #19 §19.601 and §19.602]

   a. The facility name and location

   b. The process unit or emission source deviating from the permit limit,

   c. The permit limit, including the identification of pollutants, from which deviation occurs,

   d. The date and time the deviation started,

   e. The duration of the deviation,

   f. The average emissions during the deviation,

   g. The probable cause of such deviations,

   h. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future, and

   i. The name of the person submitting the report.

j. The permittee will make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report. [40 CFR 70.6(a)(3)(iii)(B), Regulation No. 26 §26.701(C)(3)(b), Regulation No. 19 §19.601 and §19.602]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), §26.701(E) of Regulation No. 26, and A.C.A. §8-4-203, as referenced by §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation No. 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, *et seq.* and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation No. 26 §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation No. 26 §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation No. 26 §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation No. 26 §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation No. 26 §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation No. 9. [40 CFR 70.6(a)(7) and Regulation No. 26 §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation No. 26 §26.701(H)]

17. If the permit allows different operating scenarios, the permittee will, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation No. 26 §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation No. 26 §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation No. 26 §26.2. [40 CFR 70.6(c)(1) and Regulation No. 26 §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation No. 26 §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions-related activity is conducted, or where records must be kept under the conditions of this permit;

    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;

    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

    d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee will submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation No. 26 §26.703(E)(3)]

    a. The identification of each term or condition of the permit that is the basis of the certification;

b. The compliance status;

c. Whether compliance was continuous or intermittent;

d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and

e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation No. 26 §26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;

b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;

c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act or,

d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant-emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

APPENDIX A

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

APPENDIX B

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

APPENDIX C

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

APPENDIX D

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APPENDIX E

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APPENDIX F

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APPENDIX G

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APPENDIX H

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

APPENDIX I

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

APPENDIX J

This facility is subject to the regulations identified herein at the time of permit issuance. The source(s) affected by this regulation must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in the appendices of this permit. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the CFR. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit.

APPENDIX K

APPENDIX L