United States Environmental Protection Agency

Region 6 Compliance Assurance and Enforcement Division

INSPECTION REPORT

Inspection Date(s):	06/11-13/2018		
Media:	Air		
Regulatory Program(s)	Refinery Consent Decree		
Company Name:	**Lion Oil Co. dba Delek US**		
Facility Name:	**El Dorado Refinery**		
Facility Physical Location:	1005 Robert E. Lee Street		
(city, state, zip code)	El Dorado, AR 71731-7005		
Mailing address:	1005 Robert E. Lee Street		
(city, state, zip code)	El Dorado, AR 71731-7005		
County/Parish:	Union County		
Facility Contact:	Lance Thomasson	Environmental Manager	
	Lance.thomasson@delekus.com		
FRS Number:	110017419667		
Identification/Permit Number:	AR0000000513900016		
Media Number:			
NAICS:	324110		
SIC:	2911		
Personnel participating in inspection:			
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EPA Lead Inspector Signature/Date	Jim Gold gold.jim@epa.gov Digitally signed by gold.jim@epa.gov DN: cn=gold.jim@epa.gov Date: 2018.08.09 14:32:27 -05'00'		7/11/2018
	{Inspector name}		Date
Supervisor Signature/Date	SAMUEL TATES Digitally signed by SAMUEL TATES DN: c=US, o=U.S. Government, ou=USEPA, ou=Staff, cn=SAMUEL TATES, dnQualifier=0000012566 Date: 2018.08.14 16:52:18 -05'00'		
	{Supervisor name}		Date

Section I – INTRODUCTION

PURPOSE OF THE INSPECTION

EPA Region 6 inspector Jim Gold conducted an inspection of Lion Oil Co. dba Delek US - El Dorado, Arkansas Refinery (Lion Oil/Delek). At 1:00 pm on June 11, 2018, I met with Lance Thomasson, Environmental Manager the facility, for an opening conference and informed him that this was an EPA inspection to determine compliance with the federally issued Consent Decree (*United States, et al. v. Lion Oil Company, Civ. No. 03-1028 entered June 12, 2003)*, and Stipulated Order *(Case 1:03-cv-01028-HFB entered September 14, 2009)*. I also informed Mr. Thomasson that the inspection would be a Partial Compliance Evaluation (PCE), which includes an evaluation of the four marquee issues addressed by the Consent Decree (CD): Nitrogen oxide (NO_x) and sulfur dioxide (SO_2) reductions, leak detection and repair (LDAR), benzene waste operations (BWON), and, tail gas, acid gas, and hydrocarbon flaring. The consent decree (CD) consists of 19 Parts designated by Roman numerals I through XIX. Of these, Part V requires affirmative relief and is the focus of this inspection. Part IV contains the Consent Decree specific items numbers 11 through 26 that address the requirements of NO_x, SO_2, carbon monoxide (CO), particulate, volatile organic carbon (VOC), hydrogen sulfide (H_2S), and benzene emission reductions through various construction projects, process additives, and process and program enhancements.

Note that these inspection findings pertain only to the compliance status affecting the Lion Oil/Delek refinery. Photos taken during the inspection (15) are included as **APPENDIX 1**.

FACILITY DESCRIPTION

The facility has had multiple upgrades since original construction and now has the capacity to refine 70,000 barrels per day and operates as a fully integrated refinery with crude distillation, a fluid catalytic cracking unit (FCCU), alkylation (sulfuric acid), catalytic reforming, hydrodesulphurization, sulfur recovery, and fuel blending. Main products are transportation fuels. Crude oil is obtained primarily by ship and pipeline, products leave the facility by pipeline, railcar, tank truck, and marine shipping. A plant wide process flow diagram, written facility description and aerial photo are included as **APPENDIX 2**.

A detailed list of processes and descriptions can be found in Appendix A of the CD. The CD can be accessed via internet at https://www.epa.gov/sites/production/files/documents/lionoilcd.pdf.

Section II - OBSERVATIONS

Part V, Affirmative Relief/Environmental Projects

11. Control of NO_x Emissions from FCCUs

Status: Complete.

Program Summary: Lion Oil shall limit NO_x emissions from any FCCU to 20 parts per million by volume per day (ppmvd) NOx or less on a 365-day rolling average and 40 ppmvd NO_x or less on a 7-day rolling average.

Lion Oil/Delek operates one FCCU at the El Dorado refinery.

APPENDIX 3 contains the NO_x emission trends from June 1, 2017 to June 1, 2018, for both rolling averages. The trends demonstrate compliance for the 12 months preceding the inspection. The 20 ppm 365 day rolling average and 40 ppm 7 day rolling average limits are contained in the operating permit included as **APPENDIX 12**.

I observed the FCCU NO_x Continuous Emission Monitoring System (CEMS), and found that the calibration gases are of the correct concentrations and within current expiration dates. I reviewed the relative accuracy test audit (RATA) performed in May 2017 for the CEMS, and found the relative accuracies for the CEMS to be within allowable requirements of 40 Code of Federal Regulations (CFR), Part 60, Appendix F.

12. Control of SO_2 Emission from FCCUs

Status: Complete.

Program Summary: Lion Oil/Delek shall limit SO_2 emissions from any FCCU to 25 ppmvd on a 365-day rolling average and 50 ppm on a 7-day rolling average.

APPENDIX 4 contains SO_2 emissions trends for the FCCU from June 1, 2017 to June 1, 2018.

The trends demonstrate compliance for the 12 months preceding the inspection, apart from exceeding the 365-day rolling average due to the refinery losing power on November 27, 2017. I observed the SO_2 CEMS to be properly installed, and that the calibration gases are within current expiration dates and of the proper concentrations. I reviewed the RATA performed in May 2017 for the CEMS and found the relative accuracies for the CEMS to be within allowable requirements of 40 CFR, Part 60, Appendix F.

13. Control of Particulate Emissions from FCCUs

Status: Complete.

Program Summary: Lion Oil/Delek shall limit PM emissions from the FCCU to 0.5 pounds or less per 1000 pounds of coke burned in a 3-hour average basis.

Lion Oil/Delek's El Dorado refinery FCCU operates in full burn mode and PM emissions are controlled by a wet gas scrubber. Continuous parameter monitoring of pressure drop and liquid to gas (L/G) ratios. Liquid to gas (L/G) ratio for the wet gas scrubber and a minimum pressure drop have been established by stack testing.

APPENDIX 5 contains both pressure drop and L/G ratio trends for the wet gas scrubber from June1, 2017 to June 1, 2018. The trends demonstrate compliance with the established minimums.

The FCCU was tested for particulate emission in May 2017. A summary of the test results is included in **APPENDIX 5**.

I observed the opacity from the wet scrubber to be less than 10% on the days of the inspection. No Method 9 observation was necessary during the inspection.

D. Control of CO Emissions from FCCUs

Status: Complete.

Program Summary: LION OIL/DELEK shall limit CO emissions from any FCCU to 500 ppmvd or less on a 1-hour average basis and 100 ppmvd or less on a 365-day average basis.

APPENDIX 6 contains the FCCU CO emission trends for the FCCU from June 1, 2017 to June 1, 2018. The 1-hour 500 ppm limit was exceeded due to the refinery losing power.

I observed the CEMS to be properly installed and that the calibration gases are current and of the proper concentrations. I reviewed the RATA performed in May 2017 for the FCCU CEMS and found the relative accuracies for the CEMS to be within allowable requirements of 40 CFR, Part 60, Appendix F.

14. New Source Performance Standards (NSPS) Subparts A and J Applicability to FCCU Regenerator

Status: Complete.

Program Summary: Lion Oil/Delek shall comply with all requirements of 40 CFR Part 60, Subparts A and J for each relevant pollutant.

The emission trends demonstrate that the emission limits contained in NSPS Subparts A and J are being met as shown in Appendices 3-5.

16. Control of NO_x Emissions from Heaters and Boilers

Status: Complete.

Program Summary: Lion Oil/Delek shall install NOx control technology covered heaters and boilers as listed in Appendix A of the CD with a refinery wide NOx emission limit of no greater than 0.052 pounds of NOx per MMBtu.

APPENDIX 7 is an up to date list of heaters and boilers at the refinery covered by Appendix A to the CD and a list of heaters and boilers with heat input greater than 100 MMBTU/hr. requiring CEMs. **APPENDIX 7** also contains a list of heaters and boilers with installed NOx controls (lo-NO_x burners) Trends for heaters with NOx CEMS from June 1, 2017 to June 1, 2018 are also included in **APPENDIX 7**.

I reviewed the RATA results for each heater and boiler CEMS performed November 2017 and found the relative accuracies for the CEMS to be within allowable requirements of 40 CFR, Part 60, Appendix F.

17. Control of SO_2 Emissions from, and NSPS Applicability to, Heaters and Boilers

Status: Complete.

Program Summary: Lion Oil/Delek shall comply with 40 C.F.R. Part 60, Subparts A and J for fuel combustion devices.

Lion Oil/Delek 's El Dorado refinery operates a single fuel gas system. A written description is included in **APPENDIX 8**. Also included in **APPENDIX 8** is a Platformer Heater and Crude Atmospheric Heater SO_2 trends for June 1, 2017 to June 1, 2018. The facility monitors SO_2 from these two heaters in lieu of using an H_2S analyzer on the fuel gas system. The # 9 Platformer Heater is designated as the primary source for compliance allowed in condition PW 11 of the Title V operating permit contained in **Appendix 8**. And as allowed under 40 CFR 105(a) 3(iv).

I reviewed the relative accuracy test audit (RATA) results for the SO_2 CEMS and found the relative accuracies for the CEMs to be within allowable requirements of 40 CFR, Part 60, Appendix F. I observed that the H_2S analyzers were installed correctly and that the calibration gases are of the correct concentration and within current expiration dates.

<u>18. NSPS Applicability of and Compliance for Sulfur Recovery Plant</u>

According to permit conditions and SO2 emission trends the facility is complying with NSPS applicable requirements with the exceptions of upsets as shown in **Appendix 9**.

<u>19. NSPS Applicability of and Compliance for Flaring Devices</u>

Status: Complete, pending review by EPA Region 6.

<u>Program Summary</u>: Lion Oil/Delek's Sulfur Recovery Plants (SRPs) shall comply with 40 CFR Part 60, Subparts A and J.

Lion Oil/Delek's El Dorado refinery operates one SRP. SO_2 emission trends for the thermal oxidizers from June 1, 2017 to June 1, 2018 is included in **APPENDIX 9**.

The trends show compliance with NSPS emission limits for the 12-month period preceding the inspection. I observed that the sulfur pits were vented to the tail gas treatment units.

I reviewed the relative accuracy test audit (RATA) results for the CEMs and found the relative accuracies for the CEMs to be within allowable requirements of 40 CFR, Part 60, Appendix F. I observed that the analyzers were installed correctly and that the calibration gases are of the correct concentration and with current expiration dates.

Lion Oil/Delek's El Dorado refinery operates two flaring devices, the Low Pressure (LP) flare and the High Pressure (HP) flare. Both flares are subject to NSPS requirements and are tied together with a flare gas recovery system. The flare gas recovery system consists of three liquid ring sealed compressors.

Appendix 10 includes operational trends of the compressors from June 1, 2017 to June 1, 2018.

The charts indicate that the operational capacity of the system is adequate to recover the flare gases under normal operating conditions.

Appendix 10 contains a list of all hydrocarbon flaring events since the CD was entered. Reports have been generated and submitted to EPA as required.

I observed no smoke or flames being emitted by the flares. I also observed the flares using an optical gas infrared imaging device, and did not observe any abnormal flaring activity (e.g. puffing or indications of incomplete combustion). During the inspection, the High-Pressure flare was combusting a small amount of process gas due to operational adjustments.

<u>22. Benzene Waste Operations National Emission Standards for Hazardous Air Pollutants (BWON NESHAP) Program Enhancements</u>

Status: Compliance.

Program Summary: In addition to complying with 40 CFR Part 61 Subpart FF (BWON NESHAP), Lion Oil/Delek shall comply with Paragraphs B through N of the consent decree.

At the time the CD was entered Lion Oil/Delek's El Dorado refinery was determined to have a benzene annual total benzene (TAB) of less than 10 megagrams (Mg). The desalter wastewater steam is sent to a flash separator, where hydrocarbons are flashed off before the water is sent to an uncovered API oil/water separator. **Appendix 11** contains trends showing continuous operation of the flash separator. The water stream from the flash separator is sent to equalization tanks, which in turn feed an uncovered API oi/water separator that is now subject to NESAHP Subpart FF. Since the facility has exceeded 10 Mg Total Annual Benzene (TAB) the 6 Benzene Quantity (6BQ) option of 40 CFR 61.342(e) has been implemented. Since the benzene quantity leaving the equalization tanks is less than 6 Mg/year the API separator is part of the waste water treatment system and no further controls are needed.

I reviewed inspection reports for the above ground storage tanks (external floating roof tanks), and found the gap measurements of both primary and secondary seals to be within the allowable gaps allowed by NESHAP Subpart FF.

I reviewed canister inspection records for May 2018 that indicate canisters experiencing break-through have been replaced. The canister systems observed during the inspection were double canisters arranged in series as required. During the inspection I observed refinery personnel monitoring the canisters at the outlets of the primary canister, as required.

23. Leak Detection and Repair ("LDAR") Program

Status: Complete.

Program Summary: Lion Oil/Delek shall implement measures to enhance the refinery's LDAR program under 40 CFR Part 60 Subpart GGG, Part 61 Subparts J and V, and Part 63 Subparts F, H and CC.

Lion Oil/Delek's El Dorado refinery uses a contractor to conduct leak detection monitoring, repair and follow-up monitoring. Chronically leaking components are tracked and replaced. Drill and tap repair techniques are used on leaking valves if the 500 ppm limit is exceeded and the valve cannot be repaired using conventional methods. The plant wide delay of repair list was found to be up to date and lists approximately 60 components that currently require a shut down for repair. I reviewed the contractors instrument calibration logs. End of day drift check required by the CD as well as a mid-day drift check are being performed for each instrument when used.

I reviewed the quarterly precision test results for the instruments used at the facility and calibration gas certificates. I reviewed calibration records for May 2018 and found the records to be consistently logged with instrument drift calculations included. Calibration gases observed were up to date and approximately equal to the leak definitions required by EPA Method 21.

I observed that electronic data collection for LDAR monitoring is conducted using data loggers with leak tracking and reporting software.

Records indicate annual training is conducted and incorporated into new employee orientation.

I walked through the FCCU, Crude Unit, SRU Unit, Platformer, Wastewater Treatment Plant, fuel gas area, and covered boilers process units, and observed no open-ended lines or valves.

24. Permitting and Alternative Monitoring

Status: Complete.

APPENDIX 12 contains excerpts from the most recent Title V operating permit imposing emission limits and CEMS quality assurance requirements contained in the CD. Alternative Monitoring Plans addressing equipment pertaining to CD requirements have been approved by EPA and are attached to the permit. CD-imposed limits and continuous emission monitoring requirements are incorporated in federally enforceable operating permits and authorizations.

Section III – AREAS OF CONCERN

At the time the consent decree was entered the facility's total annual benzene (TAB) was less than 10 megagrams (Mg), exempting the facility from applying controls under NESHAP Subpart FF. However, beginning in 2010 the TAB exceeded 10 Mg. In the third quarter of 2009 the facility installed a second-stage desalter followed by a flash separator to reduce the TAB prior to the desalter water stream being sent to the process and storm water sewer system. The wastewater streams are collected and sent to equalization tanks prior to the wastewater treatment plant. The equalization tanks feed an above ground, uncovered API oil/water separator which feeds the waste water treatment plant

Section IV – POST INSPECTION DEBRIEFING AND FOLLOW UP

A closing conference was held with personnel listed as participating in the inspection at 11:00 a.m. on June 13th. Photos taken and process units visited during the inspection were discussed as well as LDAR spot checking. The open API separator was discussed and the need for follow-up discussions and review of the BWON program were agreed upon. It was determined that because the 6BQ option has been implemented the API separator is part of the waste water treatment system and no further controls are needed.

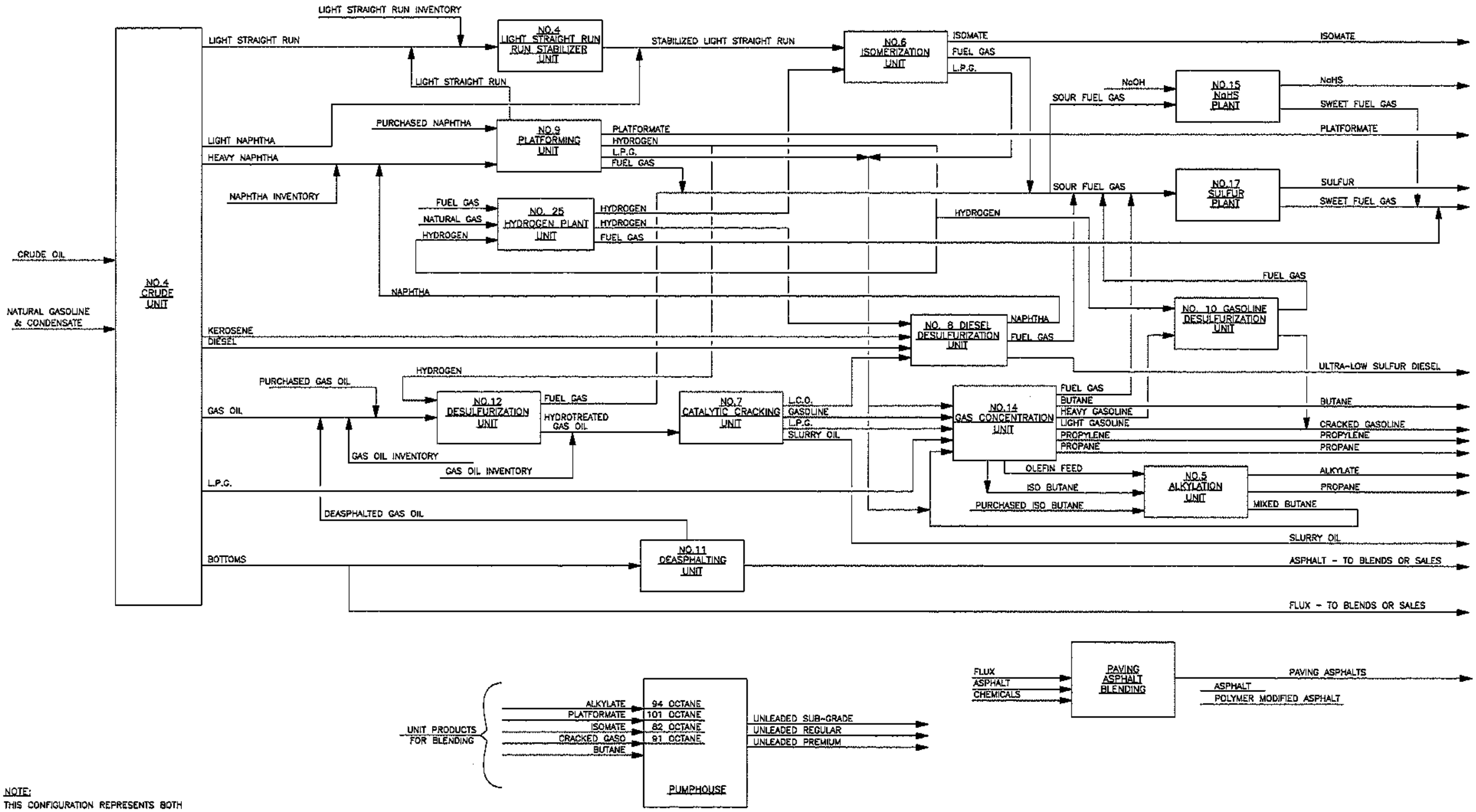
Section V – LIST OF APPENDICES

Appendix 1 - Photo Log
Appendix 2 - Plant wide process flow diagram, written description.
Appendix 3 - FCCU NO_x emission trend.
Appendix 4 - FCCU SO_2 emission trend.
Appendix 5 - FCCU Wet Gas Scrubber Parameter Monitoring.
Appendix 6 - FCCU CO emission trends with excursion explanations.
Appendix 7 - Updated list of boilers, heaters with NO_x controls, NO_x trends.
Appendix 8 - Refinery fuel gas system monitoring description and permit requirements. Plat and Vac Heater $S0_2$ emission trends.
Appendix 9 - SRP SO_2 emission trends.
Appendix 10 – Flare Gas Recovery Compressors Recorded Operational Parameters.
Appendix 11 – BWON diagram and Desalter water flash separator operation.
Appendix 12 – Operating Permits Excerpts.

CBI – not applicable.

Appendix 2

Plant wide process flow diagram, written description.



NOTE:
THIS CONFIGURATION REPRESENTS BOTH SUMMER & WINTER REFINERY OPERATIONS

REV	DATE	DESCRIPTION	BY	CHK'D
1	01/26/12	MOC 12-15-11-004-302	TED	
2	06/01/12	CORRECTED NO. 18 TO 15	TED	

LION OIL COMPANY
EL DORADO, ARKANSAS

AREA: REFINERY

LION OIL COMPANY LION OIL REFINERY
ELDORADO AR CURRENT REPRESENATIVE
OPERATION BLOCK FLOW DIAGRAM

DRAWN BY: MAJ
DATE: 7/8/05
SCALE: NONE

DRAWING NUMBER: D-40-100C
REV.: 2

#4 Crude Unit

Crude enters the refinery at the #4 Crude Unit. This unit is designed to separate approximately 80,000 BPD of light straight run gasoline and crude oil into various components of naphtha, gasoline, kerosene, diesel, gas oils and asphalt. The crude entering the refinery 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 bottoms from the Pre-flash Column is further separated in the Atmospheric Column into naphtha, kerosene, diesel, and gas oil. The Atmospheric Column bottoms are separated in the Vacuum Column into gas oil and asphalt products.

#7 Fluid Catalytic Cracking Unit

The #7 Fluid Catalytic Cracking Unit converts gas oil from the crude unit and other sources into more useful products. The gas oil is heated in a furnace then contacted with a hot 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 sets of cyclones to remove any catalyst fines and is then used to produce steam in the waste heat boiler. The light products produced in the reactor are separated in the Fractionator Tower.

#8 ULSD Hydrotreater:

The #8 ULSD Hydrotreater unit is designed to process diesel, kerosene, and light cycle oil. This unit makes ultralow sulfur diesel quality fuel from diesel feedstock by reducing the sulfur content to 15 ppm. The feed to the unit is heated 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. The stream rich in hydrogen sulfide is then sent to the sulfur recovery plant and/or NaHS unit for sulfur removal. 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 #9 unit is designed to process 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 then 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 then 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 Separators where hydrogen is separated from the platformate and recycled. The platformate is then sent to the Stabilizer where the low molecular weight gases are removed and sent to the fuel gas system. The bottoms from the Stabilizer are sent to gasoline storage.
The Continuous Catalyst Regeneration (CCR) section of the Platformer continuously burns off the coke that is deposited on the catalyst and restores catalyst activity, selectivity, and stability to essentially fresh catalyst levels.

#10 Diesel Desulfurization Unit:

The #10 Diesel Desulfurization Unit removes sulfur from a heavy cut of FCC gasoline so that the overall concentrations of sulfur in Lion Oil's gasoline pool to 30 ppm to meet the Tier II Gasoline sulfur regulations. Unit feed is heated 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:
The #11 Deasphaltizing Unit processes asphalt from the #4 Crude Unit. It separates light hydrocarbons from the asphalt to yield a product suitable for catalytic cracking while also producing an asphalt with desirable properties. Flux from the Crude Unit is pumped into the top of the Extraction Tower and flows countercurrent to a propane/butane solvent. 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 FCC. Asphalt from the bottom of the Extraction Tower is heated and 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.

#12 Distillate Hydrotreater:
The #12 Distillate Hydrotreater is a diesel and gas oil desulfurization unit whose purpose is to produce on-road diesel quality fuel. It reduces the sulfur content of light cycle oil from the #7 FCCU and kerosene and diesel from the #4 Crude Unit to less than 0.05 weight percent. The mixed feed is heated then reacted with hydrogen in the reactor. The reactor effluent is cooled 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. The liquid product flows to the Low Pressure Separator where some of the hydrogen sulfide that is 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 bottoms of the stripper are then cooled and sent to storage.

Boilers:
The three boilers in operation burn fuel gas and natural gas, but may burn fuel oil if neither of those are available.

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 that steam strips 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.

#18 Sodium Hydrosulfide Unit:
In order to use the light sour gas produced by various refinery units as fuel gas, the hydrogen sulfide must be removed to prevent excess SO_2 emissions as it is burned. The #18 Sodium Hydrosulfide Unit removes the hydrogen sulfide by contacting the fuel gas with caustic soda. The fuel gas leaving the unit then flows to the #17 Unit where it is contacted with amine.

Fuel Gas System:
Various streams enter the refinery fuel gas system directly as unit off gas streams, while others are first treated in units #18 and #17 to remove hydrogen sulfide content. All of these streams combine and enter into the two fuel gas drums before being distributed to the various heaters and boilers throughout the refinery. Additionally, purchased natural gas is used in burner pilots and to maintain fuel gas supply.

If there is a fuel gas upset it is possible to divert the excess fuel gas (NSPS) to the flare.

#17 Sulfur Recovery Plant:
The purpose of the #17 Sulfur Recovery Plant is to recover sulfur as hydrogen sulfide from fuel gas and natural gases from Great Lakes Chemical. 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 can be divided into three process units:

a. Amine Unit consisting of two (2) amine contactors
b. Sulfur Recovery Unit (SRU) (Claus)
c. 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. The acid gas (hydrogen sulfide rich) stream 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. Also, 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 remaining vapors exit 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. The remaining low concentrations of hydrogen sulfide, carbon monoxide, and hydrogen are combusted in the incinerator.

Flares:
The refinery operates a High and a Low Pressure Flare to dispose 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.

Flare Gas Recover Unit (FGRU):
The FGRU 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 FGRU 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 FGRU, the excess gas will vent through the water seal on the FGRS to the flares.

Truck Loading Racks:
The refinery operates several truck and rail loading racks. Products loaded range from asphalt to propane. 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.

#5 Alkylation Unit:
The purpose of the Alky Unit is to convert olefin feed to a high octane, low RVP gasoline blend stock. Olefin and isobutane are contacted with a sulfuric acid catalyst to make alkylate product. The reactor

product flows into an emulsion settler that separates the acid, refrigeration vapors, and effluent. The spent acid is recirculated back to the reactor. A portion of the refrigeration vapors are sent to the Depropanizer, the overheads of which is propane product and the bottoms is isobutane that is recycled back to the reactor. The other portion of the refrigeration vapors, along with reactor vapors, are compressed and sent back to the reactor for cooling. The reactor effluent is treated to remove entrained acid then fractionated in a Deisobutanizer and Debutanizer to produce alkylate for gasoline blending. Recycle isobutane and butane product are the overhead products of the DIB and DEB, respectively.

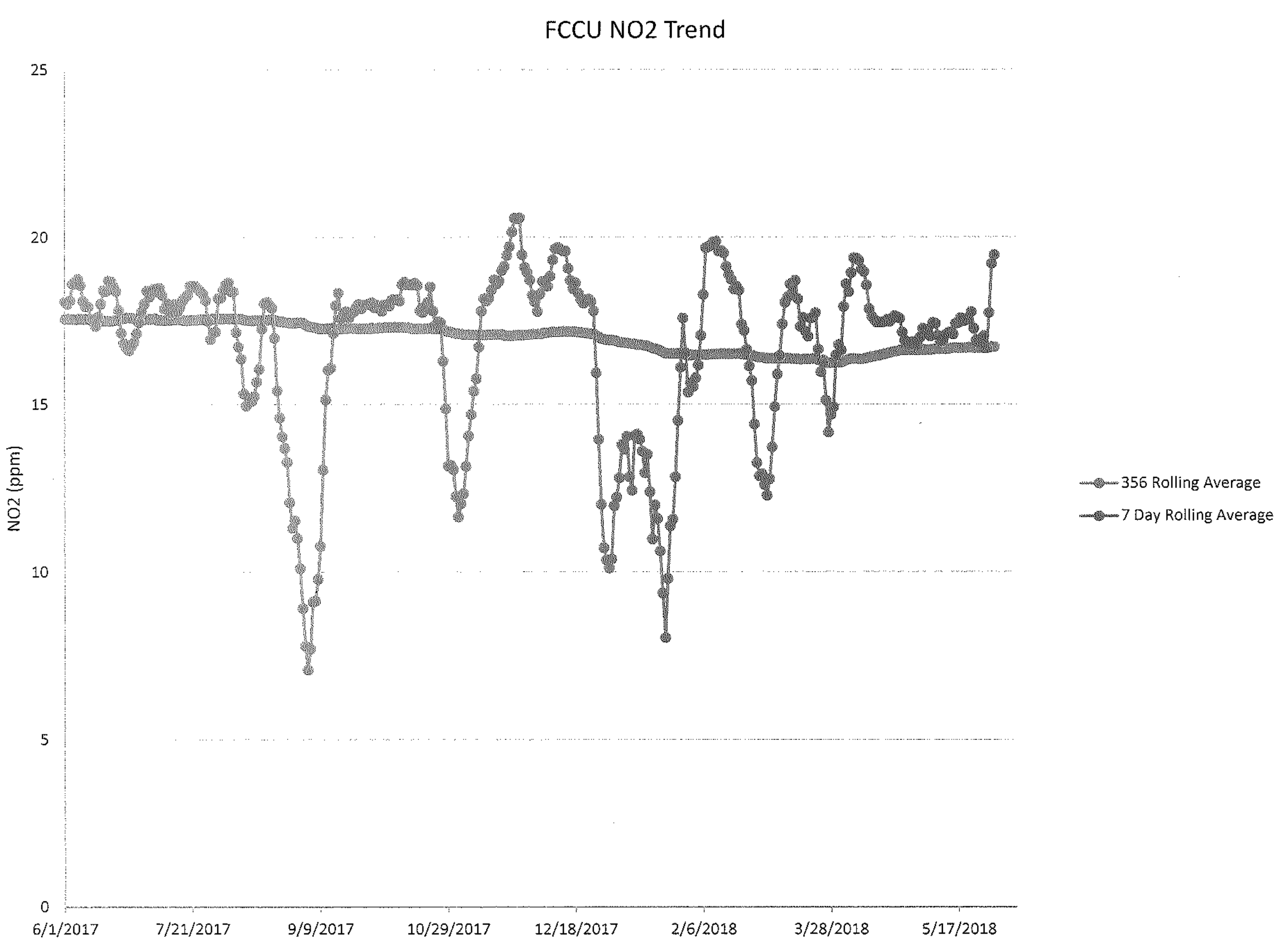
#6 Hydrotreater/Isomerization Unit:
This unit upgrades light straight run naphtha from the crude unit into a higher octane gasoline. It consists of a hydrotreater section and a penex isomerization section. In the hydrotreater, the light straight run naphtha is heated and reacted with hydrogen over a nickel/molybdenum catalyst to convert the sulfur in the feed 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 then 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.

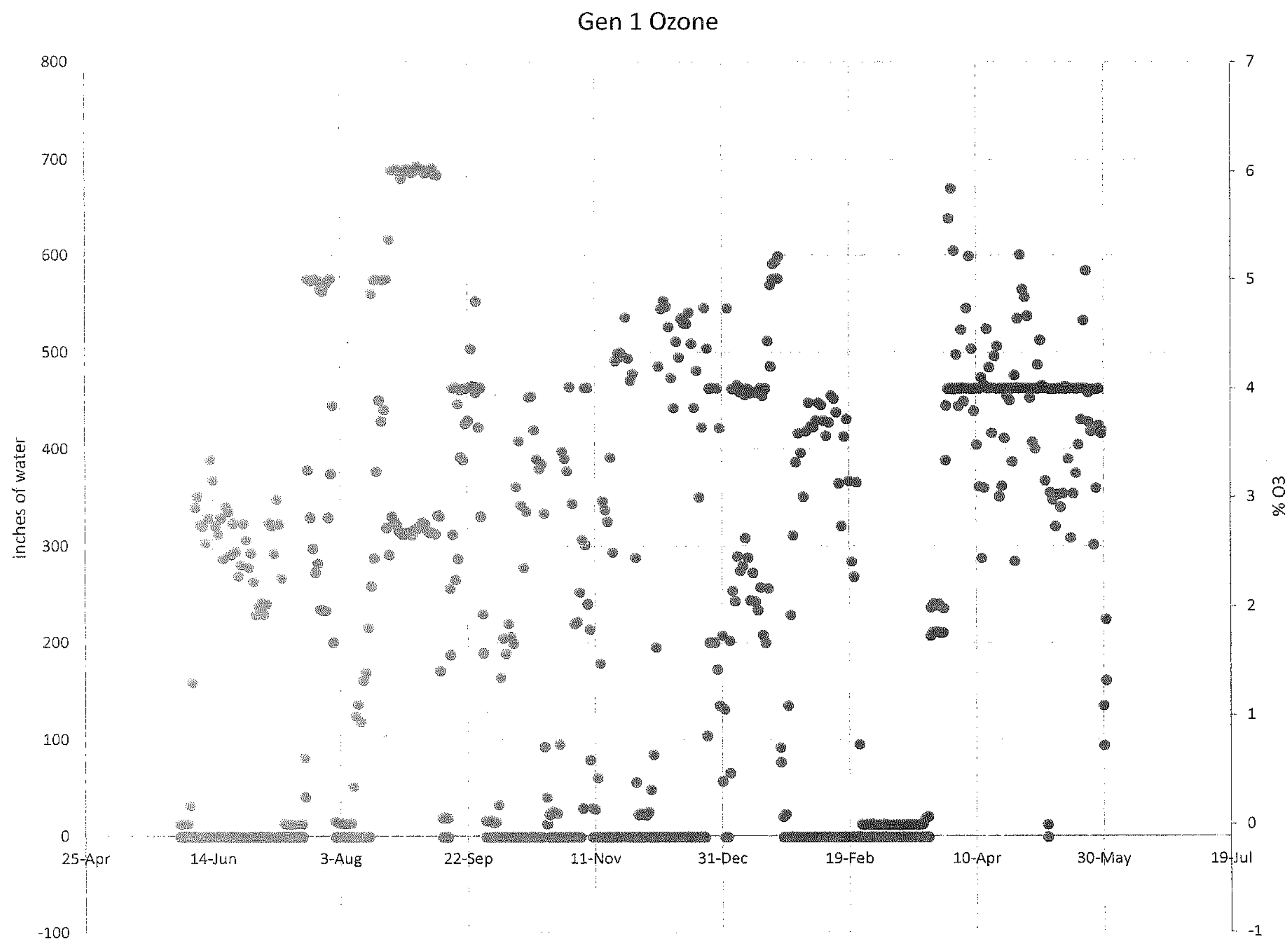
Wastewater Treatment Plant:
This unit uses a combination of chemical, biochemical, and physical processes to remove pollutants from refinery wastewater before discharging into DeLoutre Creek. The main components of the unit are dual API separators, two equalization tanks and pond, a dissolved air flotation (DAF) unit, a cooling tower, two activated sludge bio-reactors, two 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. The final effluent cooling towers cool the effluent and sludge generated at the Waste Water Treatment Plant are dewatered at the Sludge Management Facilities (SMF) prior to effluent disposal.

*The Title V Permit was referenced in writing this document

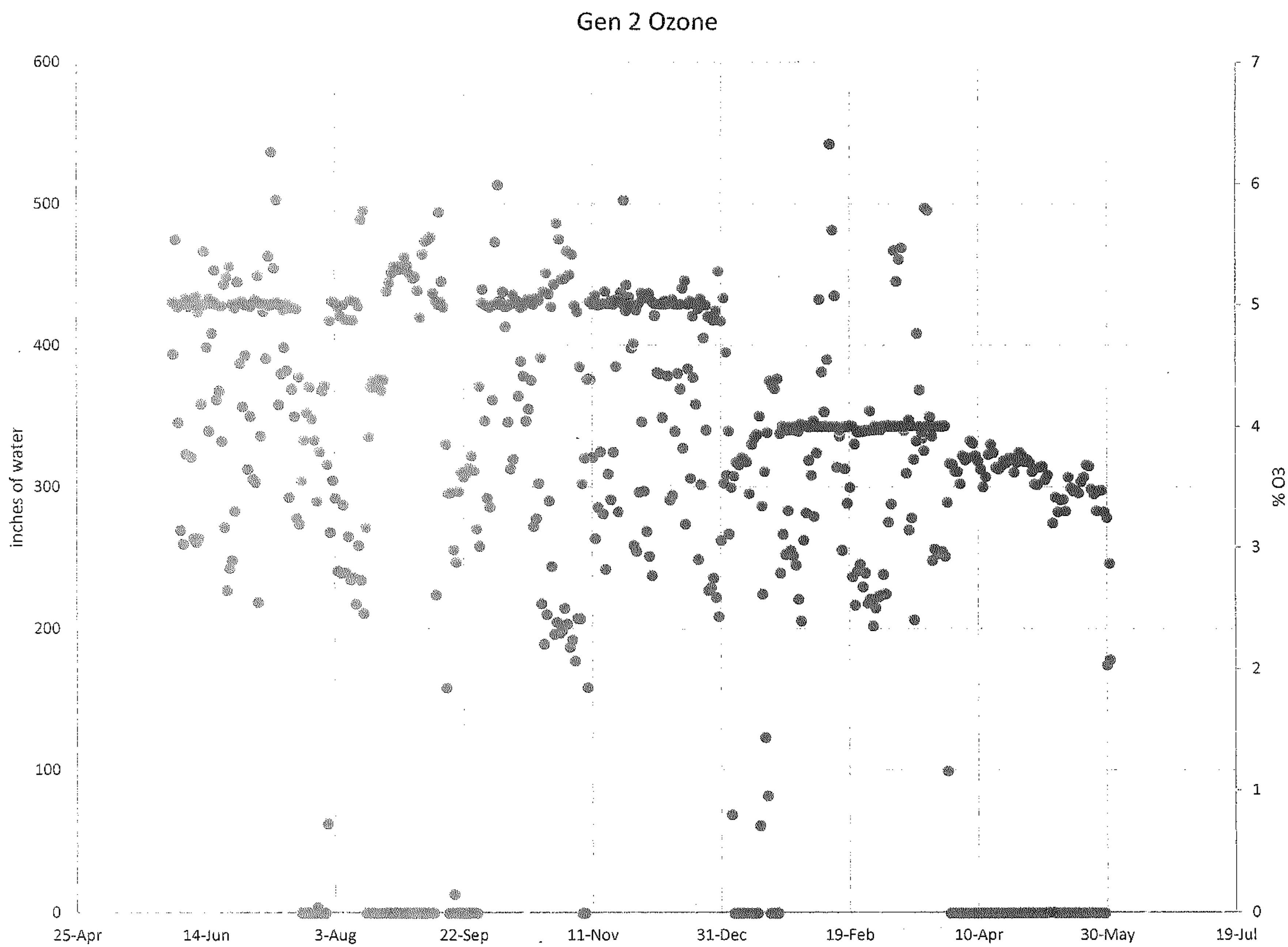
Appendix 3

FCCU NO_x emission trend.


FCCU NO2 Trend
NO2 (ppm)
0
5
10
15
20
25
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018
356 Rolling Average
7 Day Rolling Average

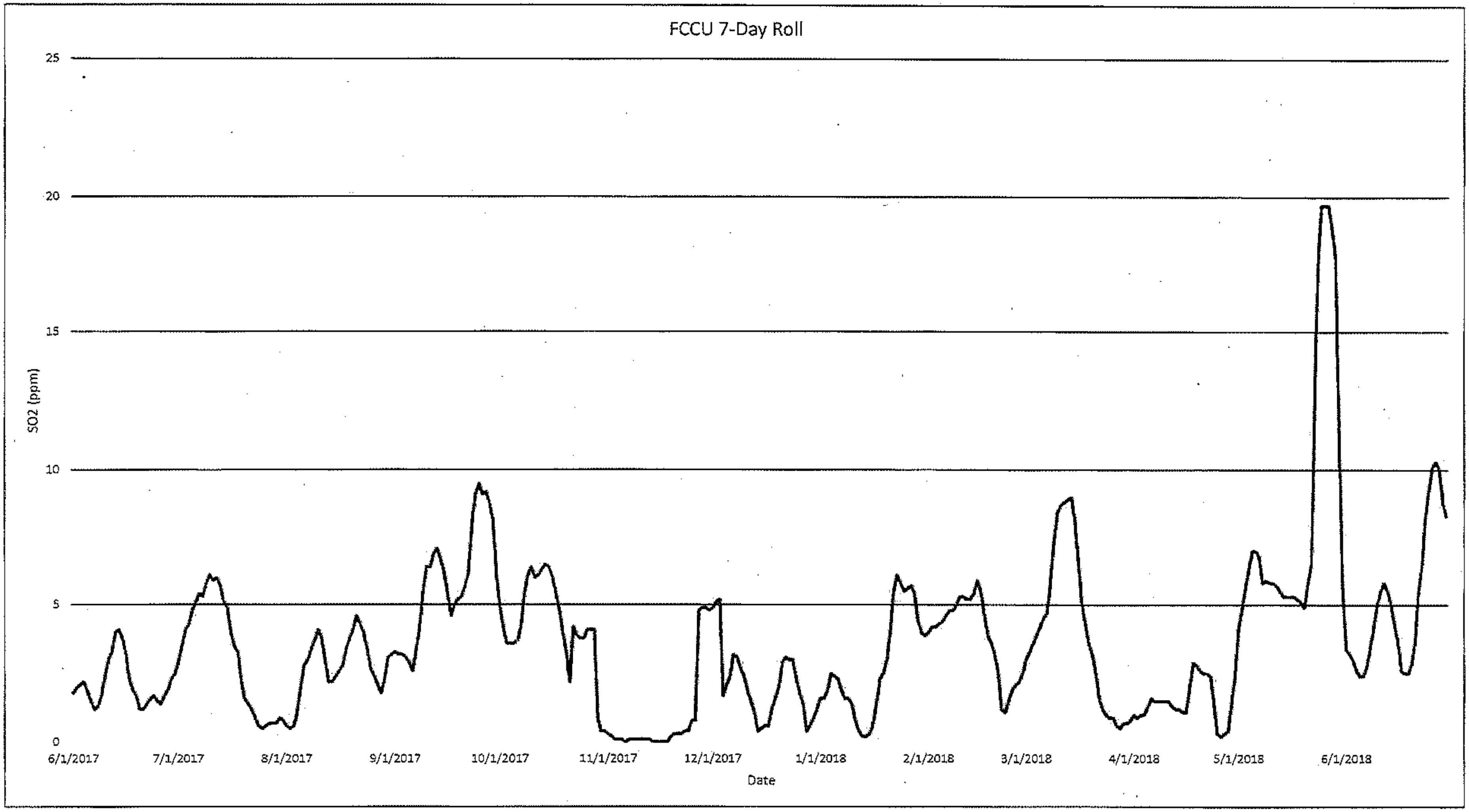


Gen 1 Ozone
inches of water
800
700
600
500
400
300
200
100
0
-100
25-Apr
14-Jun
3-Aug
22-Sep
11-Nov
31-Dec
19-Feb
10-Apr
30-May
19-Jul
% O3
7
6
5
4
3
2
1
0
-1


Gen 2 Ozone
inches of water
% O3
600
500
400
300
200
100
0
7
6
5
4
3
2
1
0
25-Apr
14-Jun
3-Aug
22-Sep
11-Nov
31-Dec
19-Feb
10-Apr
30-May
19-Jul

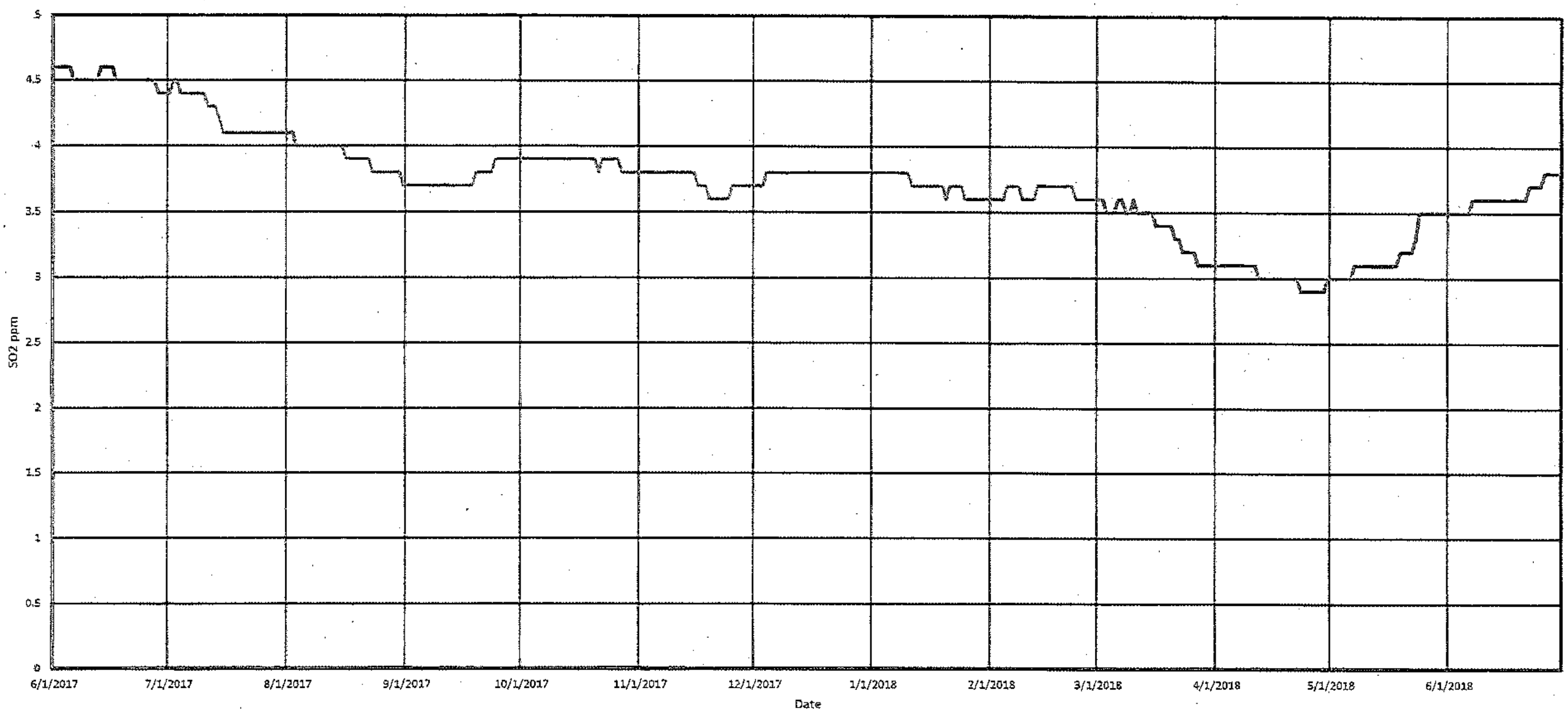
Appendix 4

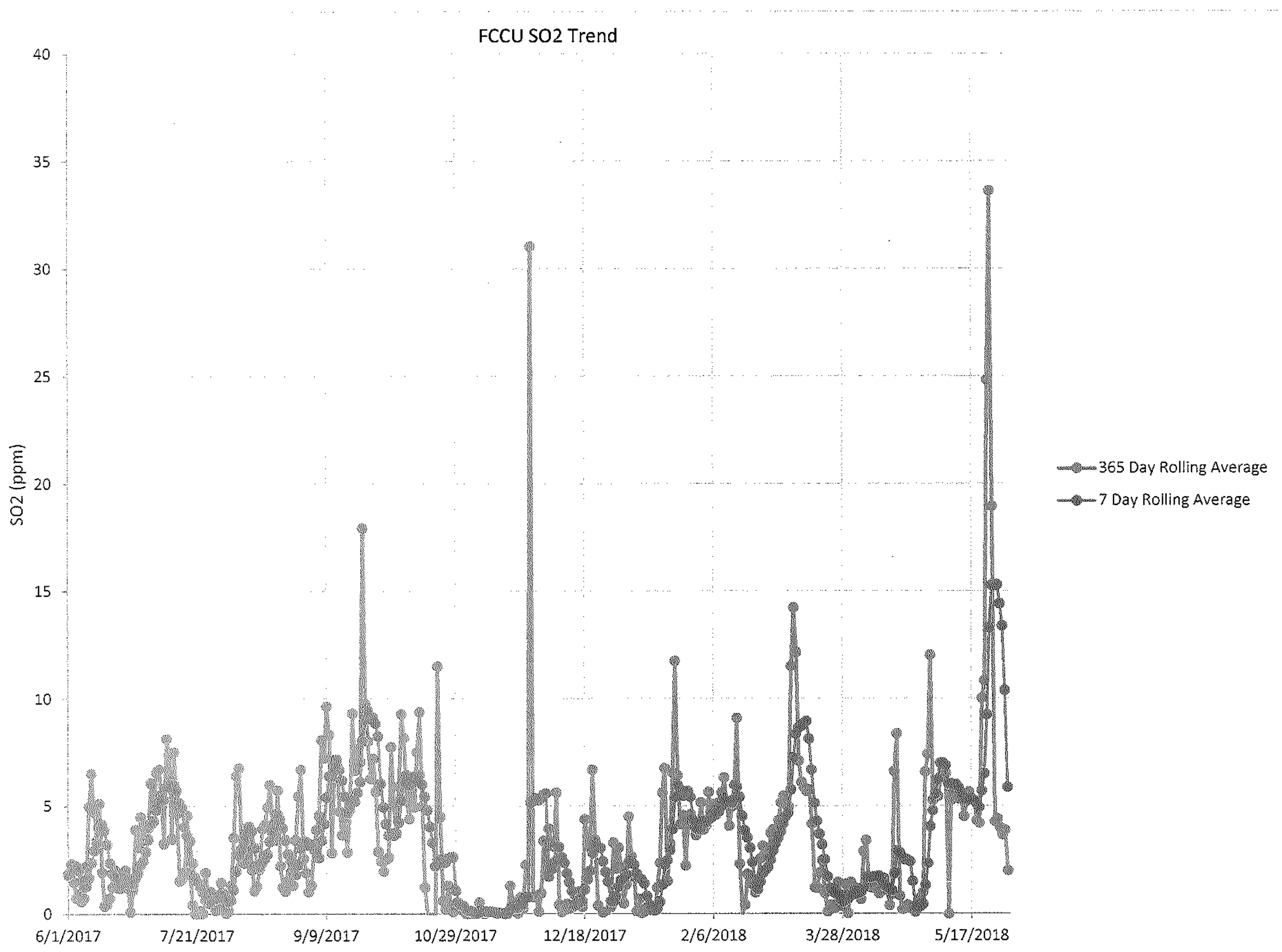
FCCU SO_2 emission trend.



FCCU 7-Day Roll
SO2 (ppm)
25
20
15
10
5
0
6/1/2017
7/1/2017
8/1/2017
9/1/2017
10/1/2017
11/1/2017
12/1/2017
1/1/2018
2/1/2018
3/1/2018
4/1/2018
5/1/2018
6/1/2018
Date

FCCU SO2 365 Day Roll




FCCU SO2 Trend
SO2 (ppm)
0
5
10
15
20
25
30
35
40
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018
365 Day Rolling Average
7 Day Rolling Average

Brief explanation of any opacity, CO, NOx and SO2 emission limits exceedances from 6/1/2017 to 6/1/2018.

OPACITY
None recorded.

NOx
None recorded.

CO
The majority of exceedance hours of CO during the past year were attributable to these events:

- Refinery power failures on 10/22/17 & 11/27/17.
- Faulty wet gas compressor flow transmitter causing the machine to go into full spillback mode. The wet gas machine along with the FCC was shut down and the transmitter replaced.
- Deficient oxygen in the regenerator requiring a rate cut.

SO2
The majority of exceedance hours of SO2 during the past year were attributable to these events:

- Refinery power failure on 11/27/17.
- Faulty wet gas compressor flow transmitter causing the machine to go into full spillback mode. The wet gas machine along with the FCC was shut down and the transmitter replaced.

Appendix 5

FCCU Wet Gas Scrubber Parameter Monitoring.

LION OIL COMPANY
EL DORADO REFINERY
1000 McHENRY
P. O. BOX 7005
EL DORADO, ARKANSAS 71731-7005
(870) 862-8111

August 11, 2011

Charles W. Handrich (6EN-AA)
United States Environmental Protection Agency
1445 Ross Avenue - Dallas, TX 75202-2733
214-665-6553
214-665-3177 (FAX)

Dear Mr. Handrich:

This letter responds to your August 10, 2011 e-mail concerning Lion Oil's 2003 request for an alternate monitoring plan under NSPS, subpart J for the fluid catalytic cracking unit (FCCU). The purpose of this letter is to advise you that no alternate monitoring plan is needed. In September 2010, Lion Oil Company's FCCU became subject to NSPS, subpart Ja and is able to comply with the monitoring requirements of subpart Ja without an AMP. Before Ja applied, Lion Oil complied with its AMP request as modified by EPA (Jonathan York) in 2005.

Lion Oil complies with the requirements of 102a(c)(2), which applies to FCCUs equipped with a wet gas scrubber. The applicable provision for an FCCU equipped with a wet gas scrubber is 105a(b)(ii), which requires either the use of a continuous parameter monitoring system (CPMS) to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate or, "as an alternate to CPMS", the requirements of (b)(1)(ii)(A) or (b). Lion Oil uses the specified CPMS alternatives.

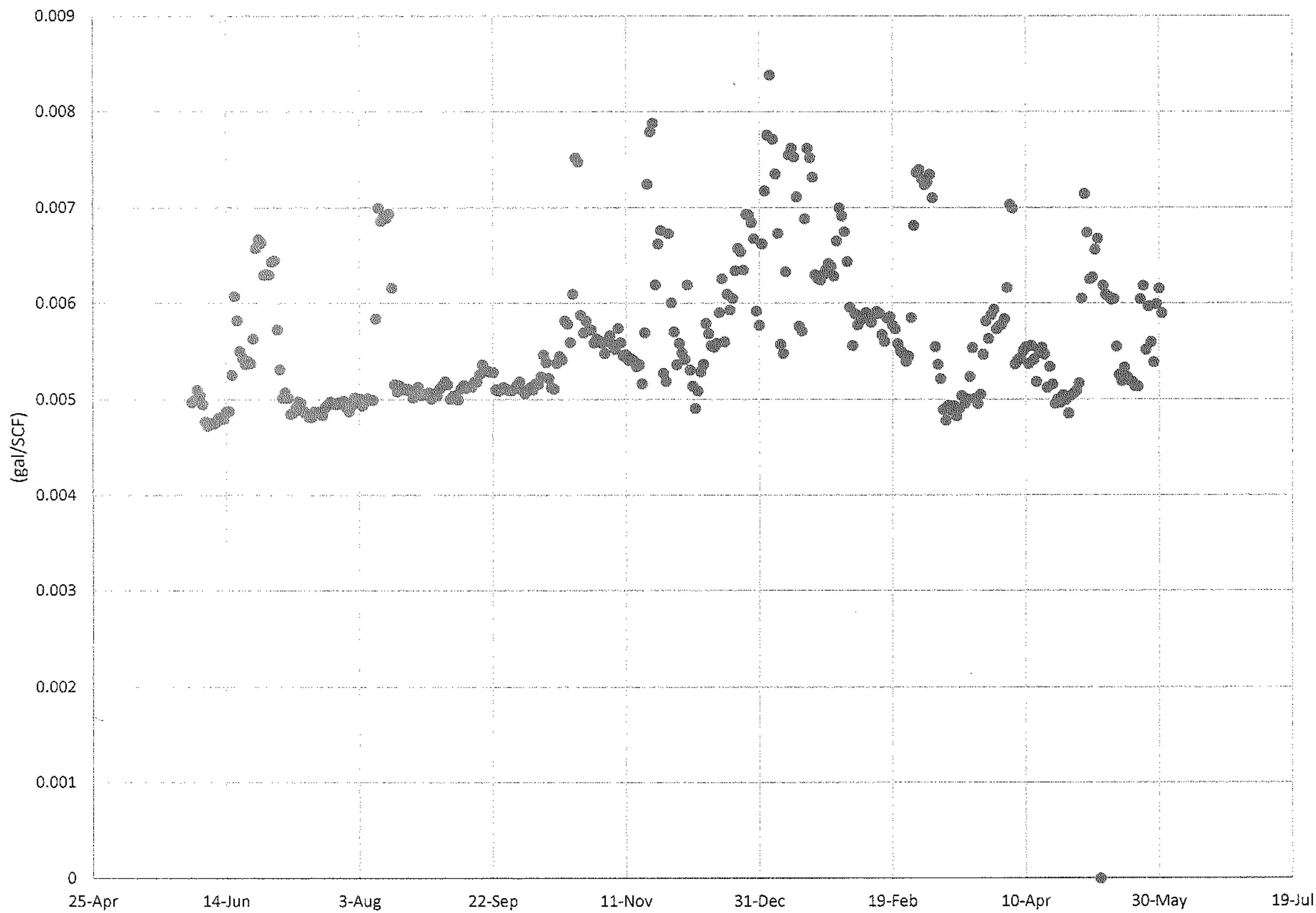
As an alternate to continuously monitoring pressure drop, Lion Oil conducts a daily check of the air or water pressure to the spray nozzles and records the results of each check in accordance with (b)(1)(ii)(A) and as an alternate to exhaust gas flow rate, Lion Oil complies with the alternate monitoring flow rate specified in 40 CFR 63.1573(a) in accordance with (b)(1)(ii)(B).

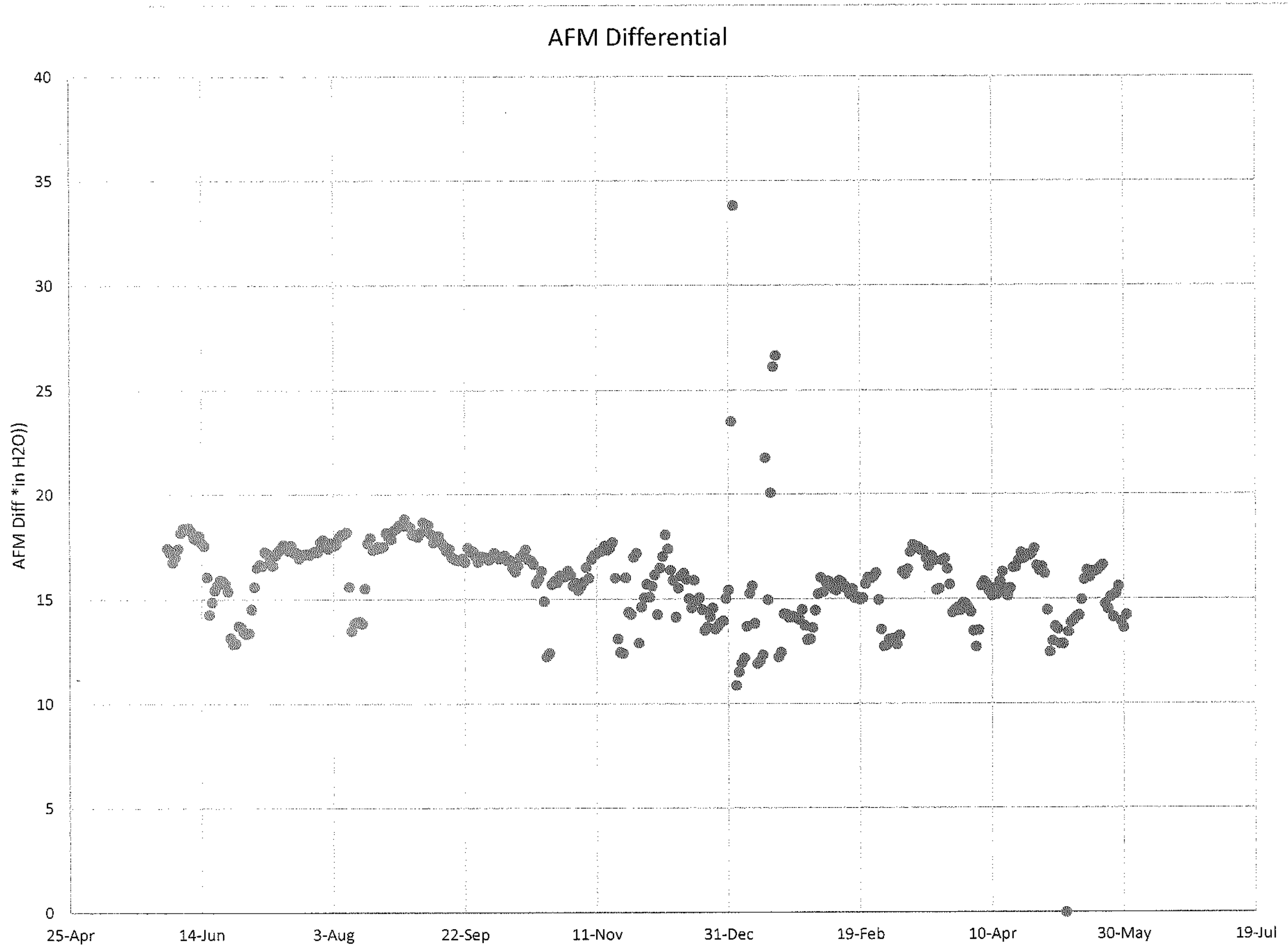
Thank you for your assistance and please contact me at 870-864-1453 if you have any questions.

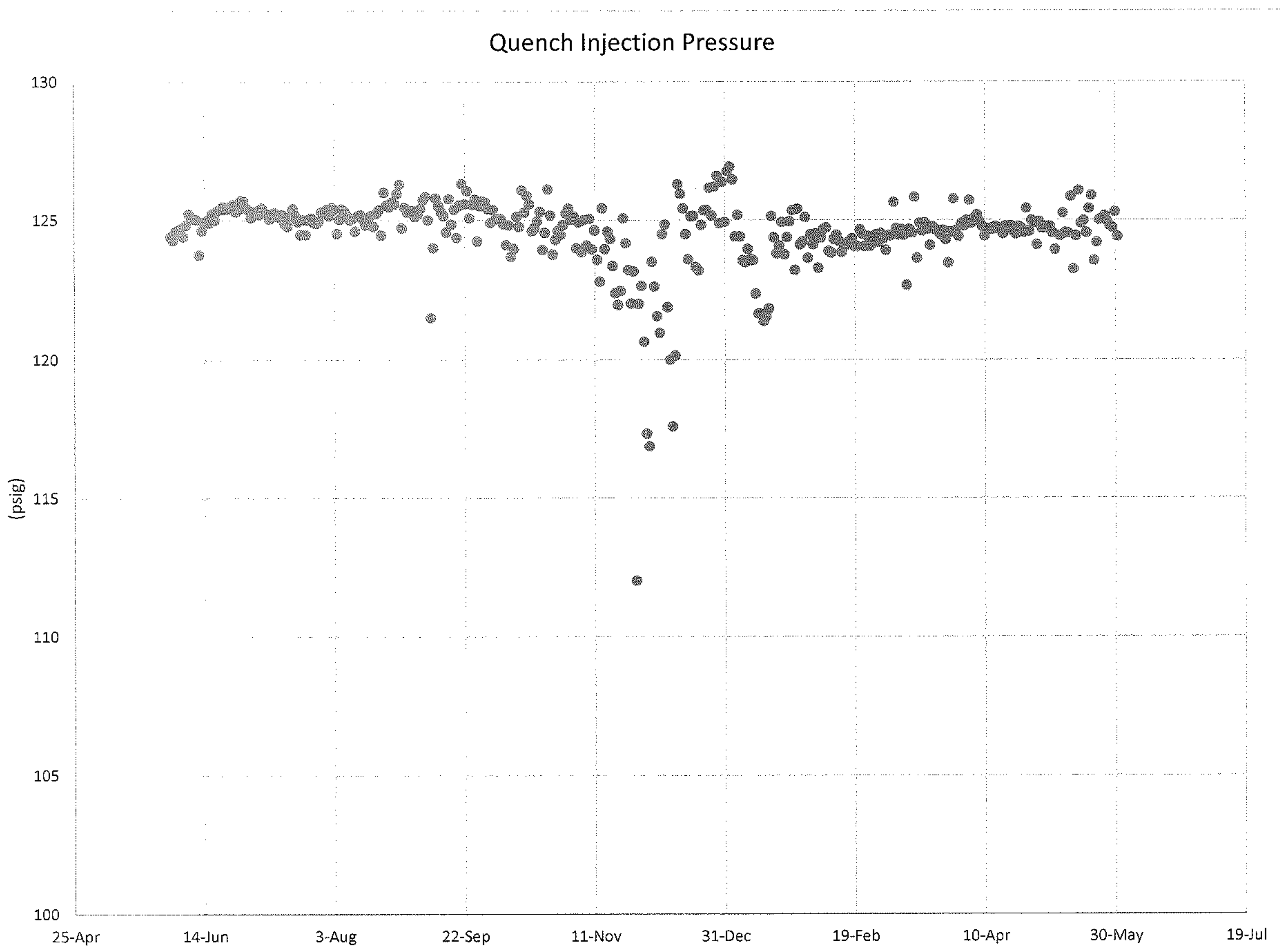
Sincerely,

George Garten
Environmental Engineering Supervisor-Air

Liquid to Gas




AFM Differential
AFM Diff *in H2O))
40
35
30
25
20
15
10
5
0
25-Apr
14-Jun
3-Aug
22-Sep
11-Nov
31-Dec
19-Feb
10-Apr
30-May
19-Jul



Quench Injection Pressure
(psig)
130
125
120
115
110
105
100
25-Apr
14-Jun
3-Aug
22-Sep
11-Nov
31-Dec
19-Feb
10-Apr
30-May
19-Jul

erthwrks

Exhaust Emission Test Report

Demonstration of Performance
of the

Fluid Catalytic Cracking Unit (FCCU)
Wet Gas Scrubber
Source Number (SN) 809

Prepared for:

Lion Oil Company

El Dorado, AR

LION

Test Date: May 23, 2016
Erthwrks Project No. 7640

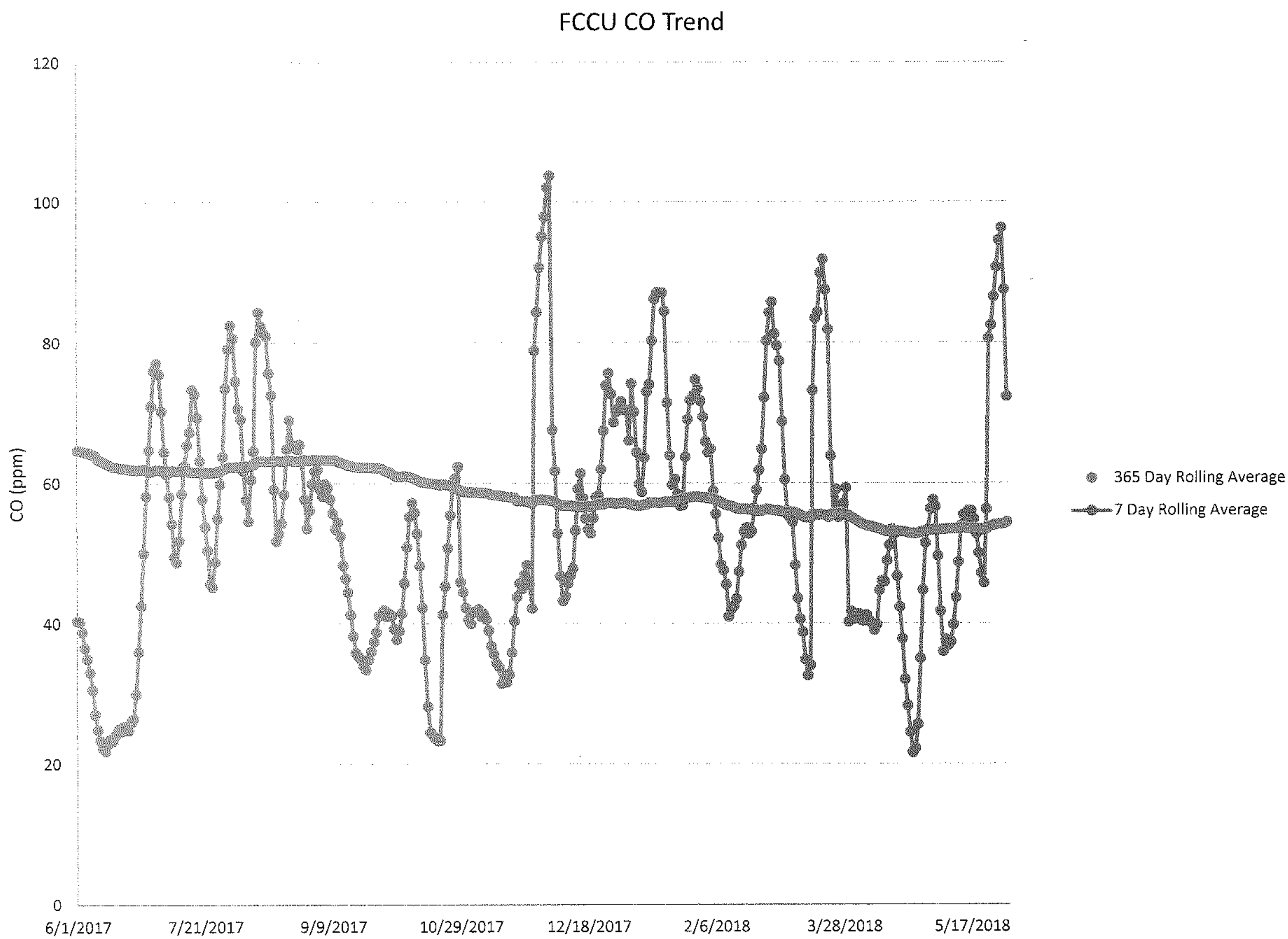
METHOD 5 - DETERMINATION OF PARTICULATE EMISSIONS - RESULTS

Plant Name	Lion Oil Refinery	**Date**	05/24/17
Sampling Location	FCC	**Project #**	
Operator	Jarrod Hoskinson	**Stack Type**	Circular

Historical Data						
Run Number		FCC-1	FCC-2	FCC-3	**Average**	
Run Start Time		4:44	6:54	8:43		hh:mm
Run Stop Time		5:49	8:00	9:47		hh:mm
Meter Calibration Factor	(Y)	0.988	0.988	0.988		
Pitot Tube Coefficient	(C_p)	0.840	0.840	0.840		
Actual Nozzle Diameter	(D_{na})	0.209	0.209	0.209		in
Stack Test Data						
Initial Meter Volume	$(V_m)_i$	145.470	168.800	208.510		ft^3
Final Meter Volume	$(V_m)_f$	166.980	193.036	234.053		ft^3
Total Meter Volume	(V_m)	21.510	24.236	25.543	23.763	ft^3
Total Sampling Time	(Θ)	60.0	60.0	60.0	60.0	min
Average Meter Temperature	$(t_m)_{avg}$	59.9	59.3	81.0	66.7	^oF
Average Stack Temperature	$(t_s)_{avg}$	136.5	138.2	140.0	138.2	^oF
Barometric Pressure	(P_b)	28.90	28.99	28.90	28.93	in Hg
Stack Static Pressure	(P_{static})	0.14	0.14	0.14	0.14	in H_2O
Absolute Stack Pressure	(P_s)	28.91	29.00	28.91	28.94	in Hg
Average Orifice Pressure Drop	$(\Delta H)_{avg}$	0.46	0.44	0.39	0.43	in H_2O
Absolute Meter Pressure	(P_m)	28.93	29.02	28.93	28.96	in Hg
Avg Square Root Pitot Pressure	$(\Delta p^{1/2})_{avg}$	0.65	0.65	0.63	0.64	$(in\ H_2O)^{1/2}$
Moisture Content Data						
Impinger Weight Gain	(W_n)	117.2	129.5	141.7	129.5	g
Total Water Volume Collected	(V_{lc})	117.4	129.7	142.0	129.7	ml
Standard Water Vapor Volume	$(V_w)_{std}$	5.527	6.107	6.682	6.105	scf
Standard Meter Volume	$(V_m)_{std}$	20.871	23.618	23.814	22.768	dscf
Calculated Stack Moisture	($B_{ws(calc)}$)	20.9	20.5	21.9	21.1	%
Gas Analysis Data						
Carbon Dioxide Percentage	($\%CO_2$)	14.4	14.8	14.3	14.5	%
Oxygen Percentage	($\%O_2$)	2.8	2.5	2.6	2.6	%
Dry Gas Molecular Weight	(M_d)	30.41	30.47	30.38	30.42	lb/lb-mole
Wet Stack Gas Molecular Weight	(M_s)	27.81	27.90	27.67	27.80	lb/lb-mole
Volumetric Flow Rate Data						
Average Stack Gas Velocity	(v_s)	39.92	40.05	39.12	39.70	ft/sec
Stack Cross-Sectional Area	(A_s)	25.22	25.22	25.22	25.22	ft^2
Actual Stack Flow Rate	(Q_{aw})	60413	60604	59203	60074	acfm
Wet Standard Stack Flow Rate	(Q_{sw})	3009	3063	2959	3011	wkscfh
Dry Standard Stack Flow Rate	(Q_{sd})	40853	41199	39311	40454	dscfm
Percent of Isokinetic Rate	(I)	90.1	101.1	106.9	99.4	%
Emission Rate Data						
lbs of Coke burned	(m_f)	10557	10011	11022	10530	lbs
Mass of Particulate on Filter	(m_f)	8.7	10.4	21.7	13.6	mg
Mass of Particulate in Acetone	(m_a')	3.8	1.5	1.6	2.3	mg
Mass of Condensible PM	(W_a)	18.5	13.6	13.0	15.0	mg
Total Mass of Particulates	(m_n)	31.0	25.5	36.3	30.9	mg
Particulate Emission Rate	(E)	1.46	1.24	2.30	1.67	kg/hr
Filterable PM only	(E)	**3.2**	**2.7**	**5.1**	**3.7**	**lbs/hr**
	(E)	**0.31**	**0.27**	**0.46**	**0.35**	**lbs/1000lbs Coke Burn**
Particulate Emission Rate	(E)	3.63	2.67	3.59	3.30	kg/hr
Filterable and Condensable PM	(E)	**8.01**	**5.88**	**7.92**	**7.27**	**lbs/hr**
	(E)	**0.76**	**0.59**	**0.72**	**0.69**	**lbs/1000lbs Coke Burn**

Appendix 6

FCCU CO emission trends with excursion explanations.


FCCU CO Trend
CO (ppm)
0
20
40
60
80
100
120
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018
365 Day Rolling Average
7 Day Rolling Average

Brief explanation of any opacity, CO, NOx and SO2 emission limits exceedances from 6/1/2017 to 6/1/2018.

OPACITY
None recorded.

NOx
None recorded.

CO
The majority of exceedance hours of CO during the past year were attributable to these events:

- Refinery power failures on 10/22/17 & 11/27/17.
- Faulty wet gas compressor flow transmitter causing the machine to go into full spillback mode. The wet gas machine along with the FCC was shut down and the transmitter replaced.
- Deficient oxygen in the regenerator requiring a rate cut.

SO2
The majority of exceedance hours of SO2 during the past year were attributable to these events:

- Refinery power failure on 11/27/17.
- Faulty wet gas compressor flow transmitter causing the machine to go into full spillback mode. The wet gas machine along with the FCC was shut down and the transmitter replaced.

Appendix 7

Updated list of boilers, heaters with NO_x controls, NO_x trends.

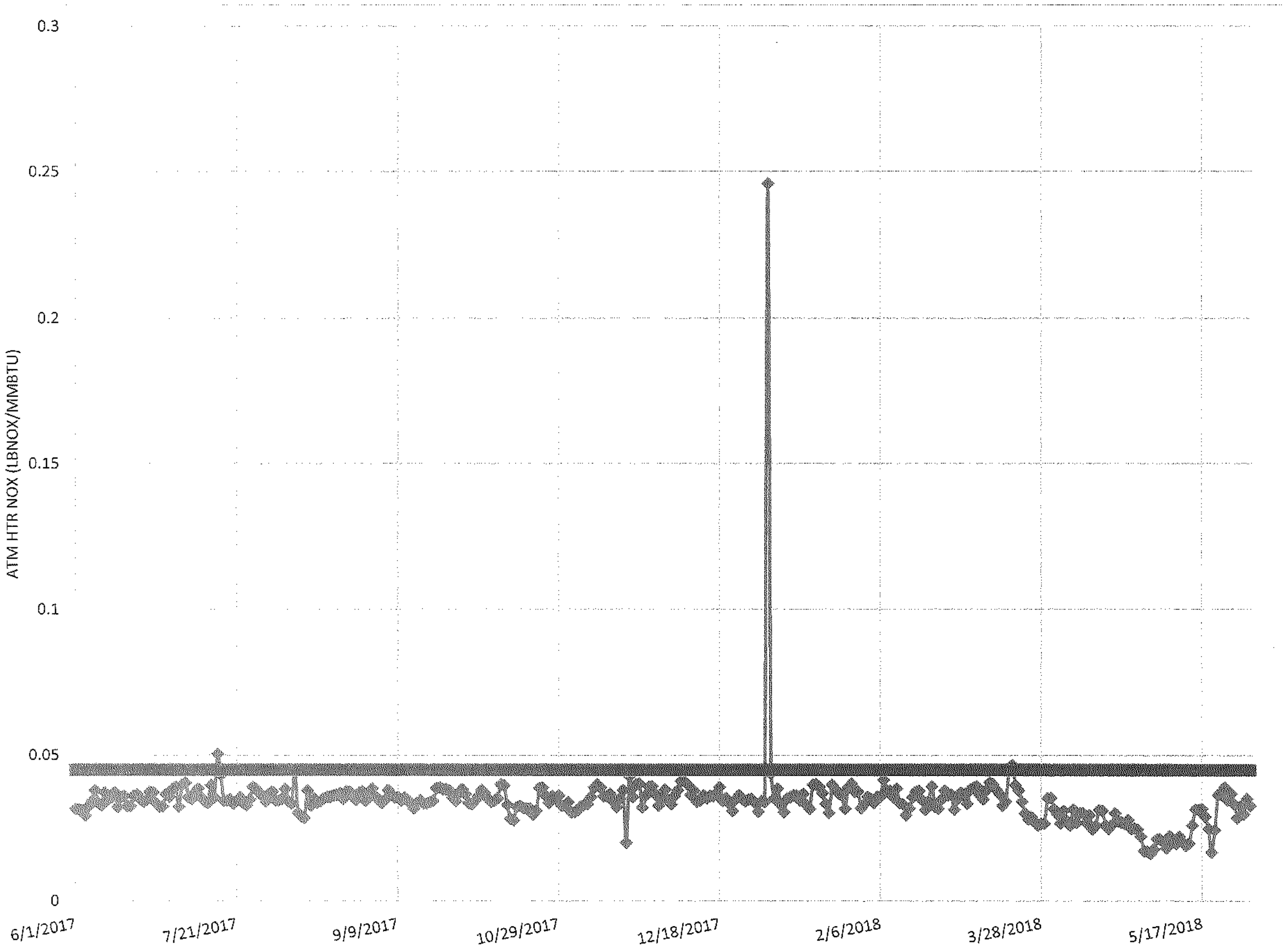
Heater/Boilers Subject to CD	
Source	NOx Control Technology
#4 Pre-flash Column Reboiler (SN-803)	Ultra Low NOx burners
#4 Atmospheric Heater (SN-804)	Ultra Low NOx burners
#4 Pre-flash Reboiler (SN-805)	Ultra Low NOx burners
#4 Vacuum Heater (SN-805N)	Ultra Low NOx burners
#7 FCCU Heater (SN-808)	Ultra Low NOx burners
#9 Hydrotreater Heater (SN-810)	Ultra Low NOx burners
#9 Reformer (Plat) Heater (SN-811)	Ultra Low NOx burners
#10 Hydrotreater Heater (SN-813a)	Ultra Low NOx burners
#12 Distillate Hydrotreater Heater (SN-842)	Ultra Low NOx burners
~~G398TA Air Compressor (SN-841)~~	Out Of Service
~~8GTL Compressor (SN-836)~~	Out Of Service
#18 Boiler (SN-821a)	Ultra Low NOx burners
#19 Boiler (SN-821b)	Ultra Low NOx burners
#20 Boiler (SN-821c)	Ultra Low NOx burners
~~Asphalt Fume Incinerator (SN-824)~~	Out Of Service
~~#10 Boiler (SN-816)~~	Out Of Service
~~#11 Boiler (SN-817)~~	Out Of Service
~~#12 Boiler (SN-818)~~	Out Of Service
~~#13 Boiler (SN-819)~~	Out Of Service
~~#14 Boiler (SN-820)~~	Out Of Service

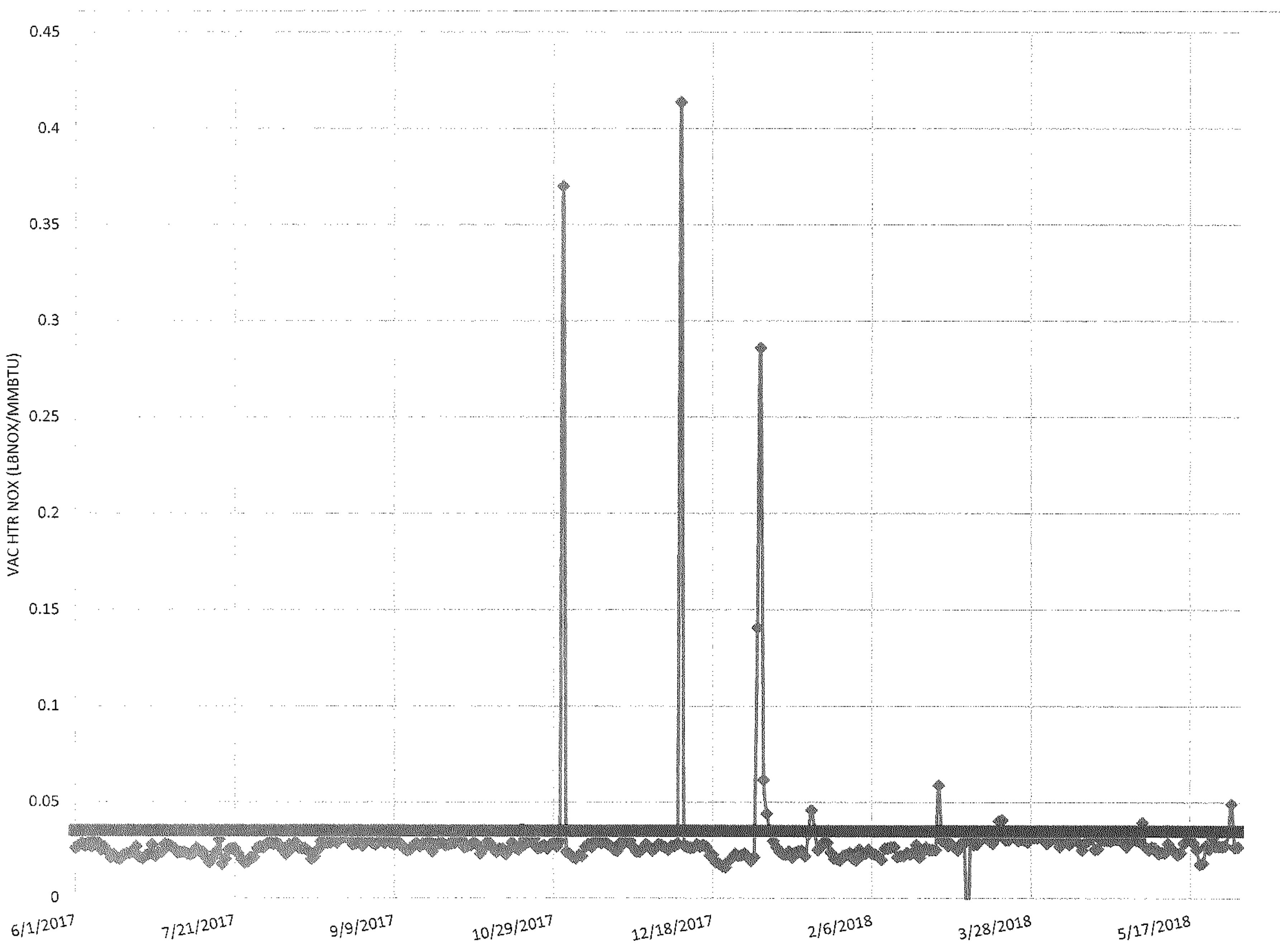
CEMS Boilers and Heaters List with NOx Technology

Common Name	Source Number	Pollutants	Burner NOx Technology
Boiler 18	821.a	SO_2	Ultra Low NOx Burners
		NO_X	
		lb_{NOx}/MMBTU	
		CO	
		O_2	
Boiler 19	821.b	SO_2	Ultra Low NOx Burners
		NO_X	
		lb_{NOx}/MMBTU	
		CO	
		O_2	
Boiler 20	821.c	SO_2	Ultra Low NOx Burners
		NO_X	
		lb_{NOx}/MMBTU	
		CO	
		O_2	
#4 Vacuum Heater	805N	SO_2	Ultra Low NOx Burners
		NO_X	
		O_2	
		lb_{NOx}/MMBTU	
#9 Platformer Heater	811	SO_2	Ultra Low NOx Burners
		NO_X	
		O_2	
		lb_{NOx}/MMBTU	
#4 Atmospheric Heater	804	SO_2	Ultra Low NOx Burners
		NO_X	
		O_2	
		lb_{NOx}/MMBTU	
#7 FCCU Belco Scrubber	809	SO_2	-
		NO_X	
		CO	
		O_2	
Sulfur Recovery Unit	844	SO_2	-
		O_2	
		SO_2	

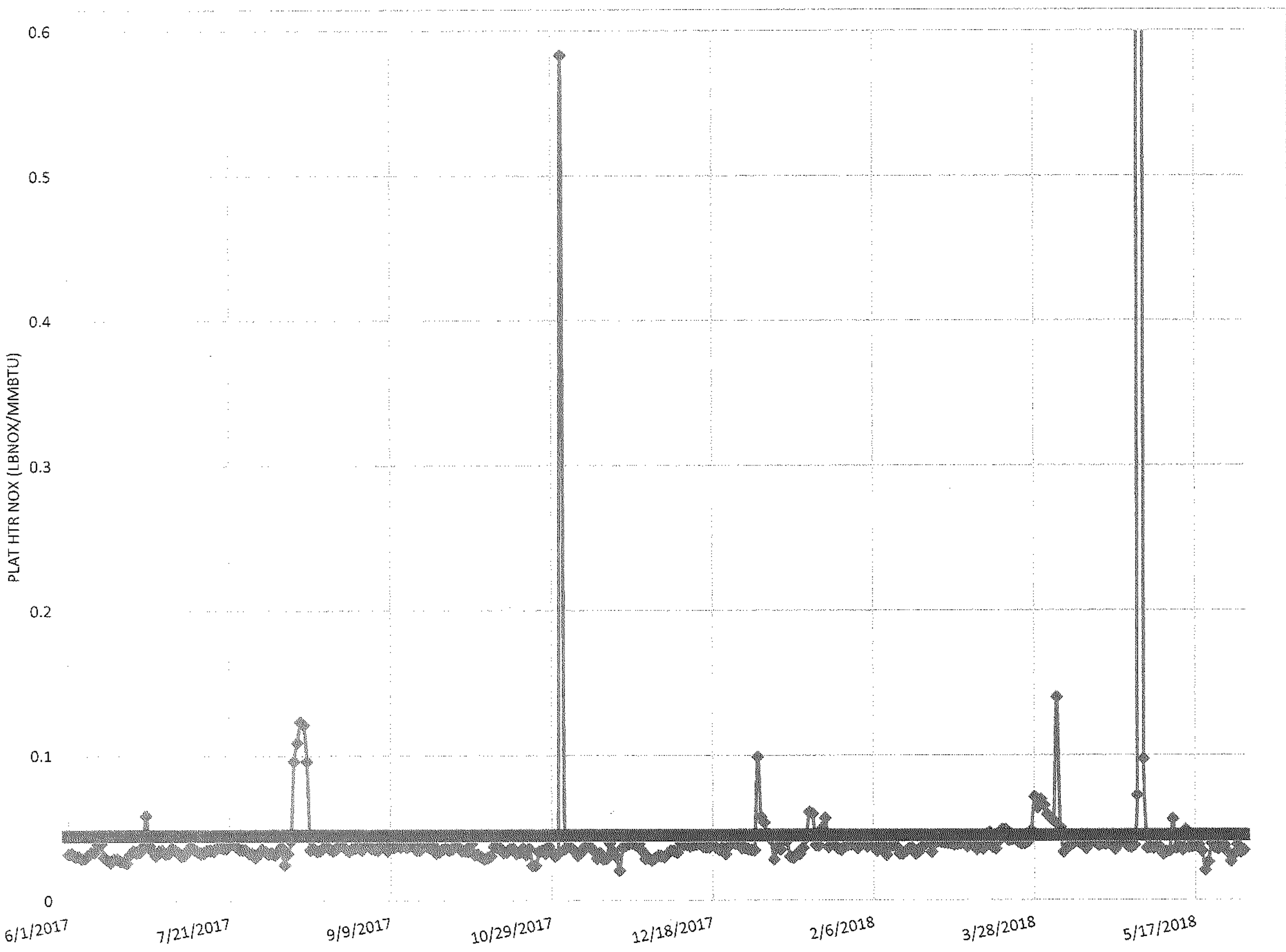
CEMS Boilers and Heaters List

SOURCE NUMBER	MONITOR TYPE	POLLUTANTS
821.a	Ametek 922 SO2	SO_2
	Ametek 922 NOX	NO_X
	NA	lb_{NOx}/MMBTU
	Servomex 4900 CO	CO
	Ametek_LC CEM O_2	O_2
821.b	Ametek 922 SO2	SO_2
	Ametek 922 NOX	NO_X
	NA	lb_{NOx}/MMBTU
	Servomex 4900 CO	CO
	Ametek_LC CEM O_2	O_2
821.c	Ametek 922 SO2	SO_2
	Ametek 922 NOX	NO_X
	NA	lb_{NOx}/MMBTU
	Servomex 4900 CO	CO
	Ametek_LC CEM O_2	O_2
805N	Ametek 9000 RM	SO_2
	Ametek 9000 RM	NO_X
	Thermox_RM CEM O2/IQ	O_2
	NA	lb_{NOx}/MMBTU
811	Ametek 9000 RM	SO_2
	Ametek 9000 RM	NO_X
	Thermox_RM CEM O2/IQ	O_2
	NA	lb_{NOx}/MMBTU
804	Ametek 922 W SO2	SO_2
	Ametek 922 W NOx	NO_X
	Ametek LC CEM O2	O_2
	NA	lb_{NOx}/MMBTU
809	Ametek 922 W SO_2/NO_X	SO_2
	Teledyne 200EH NOx	NO_X
	Servomex 9400 CO	CO
	Ametek_LC CEM O_2	O_2
844	Ametek 721M SO_2 S/N 9471482321	SO_2
	Thermox O_2_S/N C133213	O_2
	SO_2 Mass Flow	SO_2

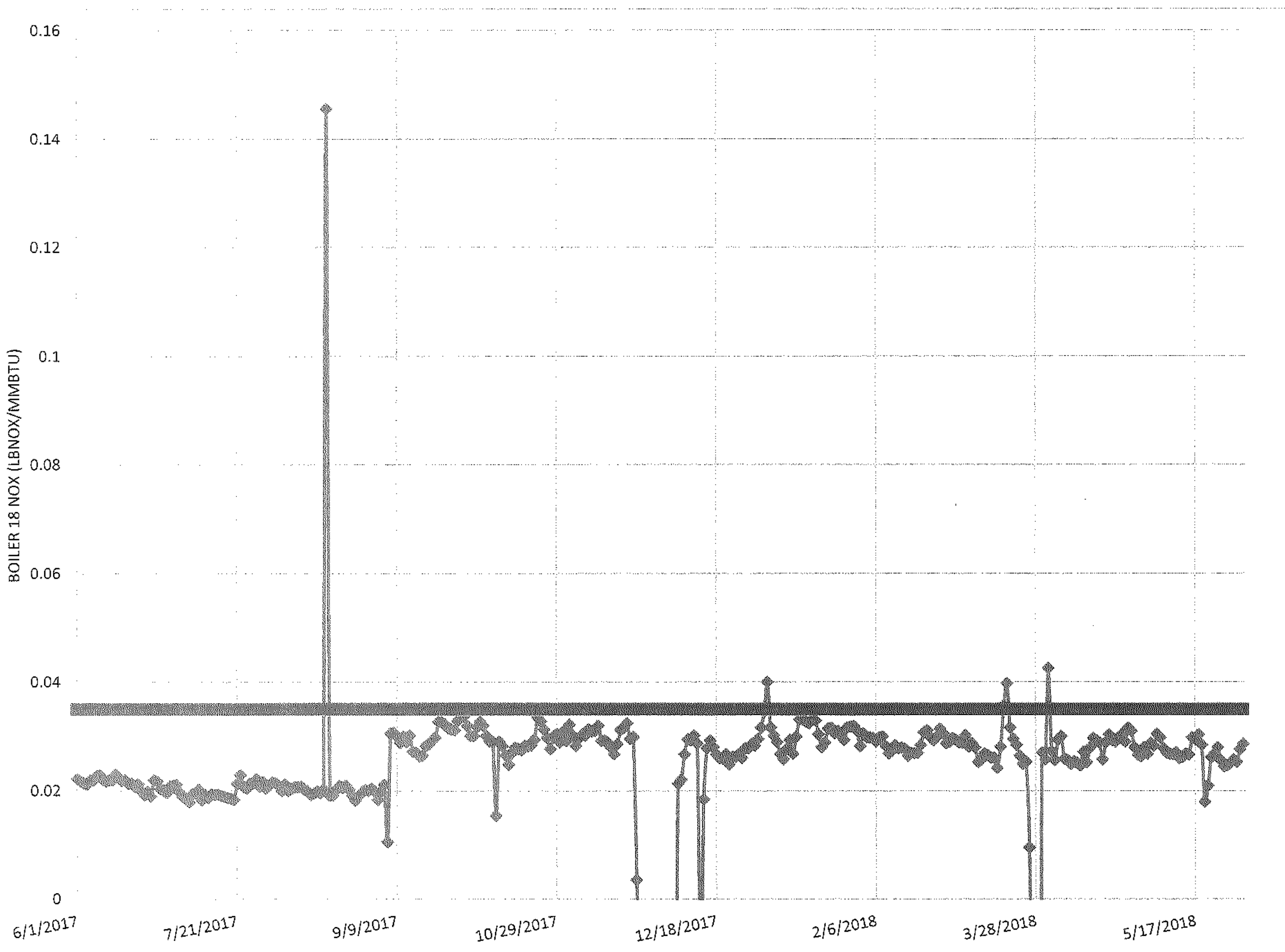

ATM HTR NOX (LBNOX/MMBTU)
0.3
0.25
0.2
0.15
0.1
0.05
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018



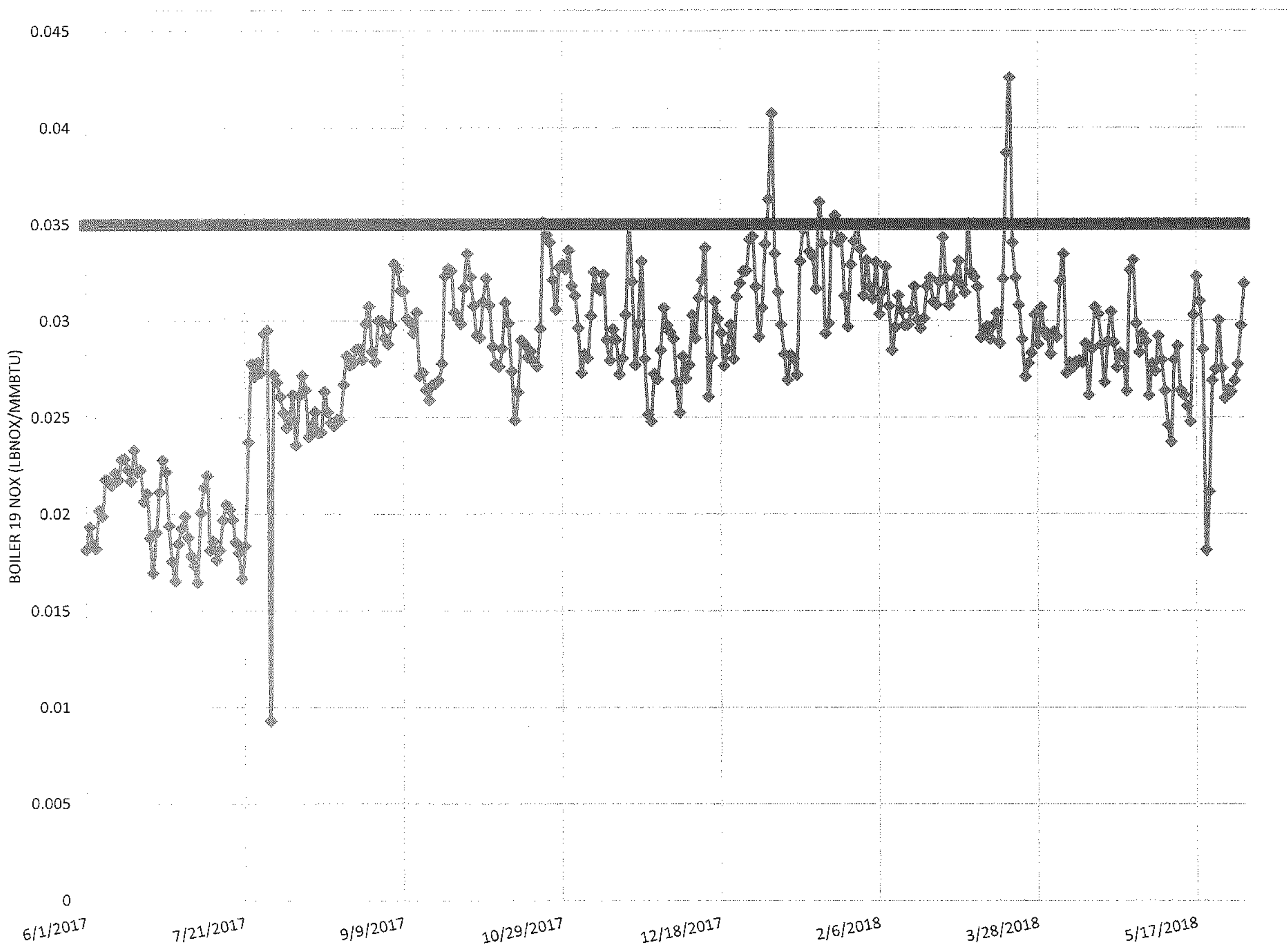
VAC HTR NOX (LBNOX/MMBTU)
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018



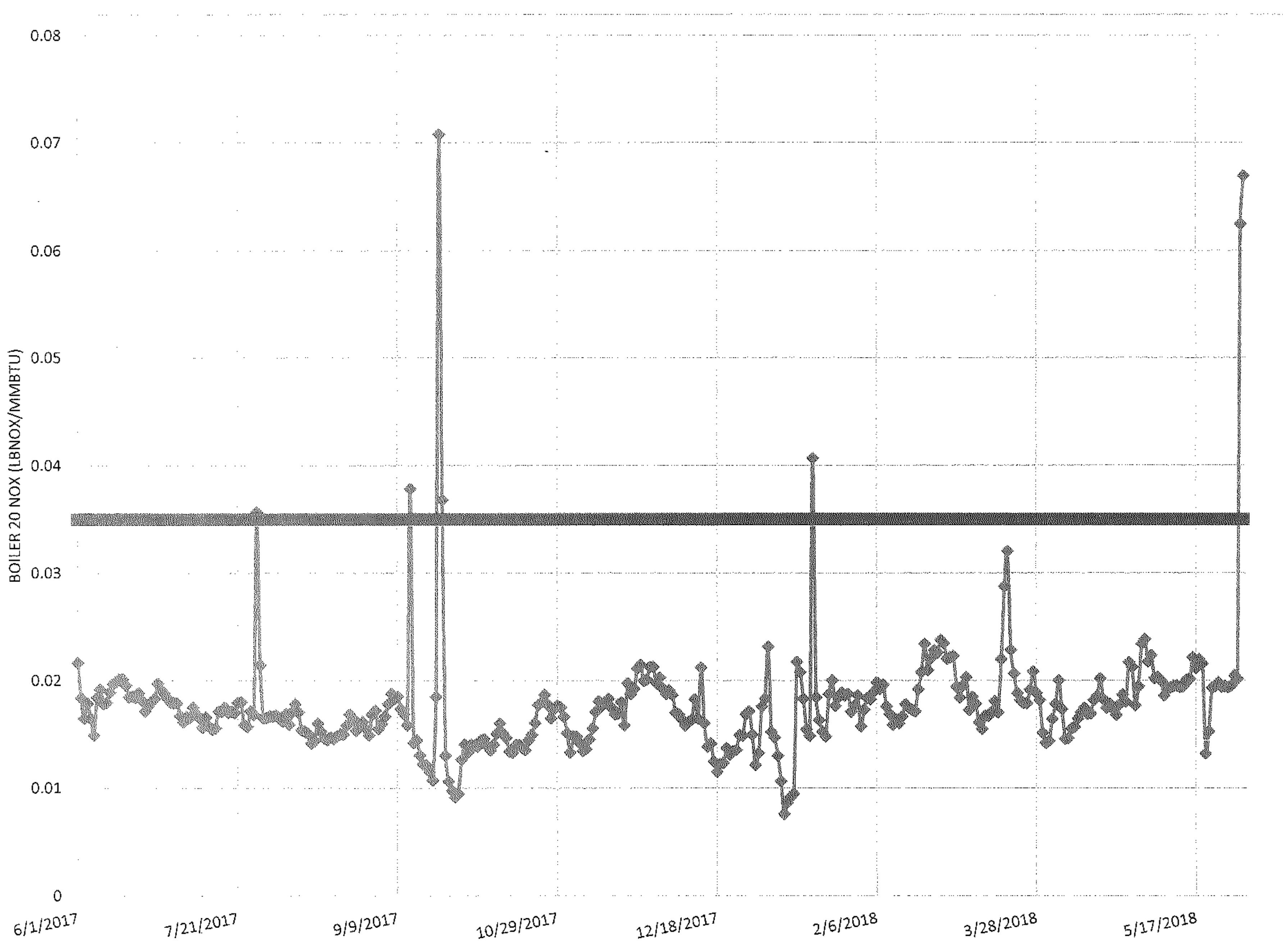
PLAT HTR NOX (LBNOX/MMBTU)
0.6
0.5
0.4
0.3
0.2
0.1
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018



BOILER 18 NOX (LBNOX/MMBTU)
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018



BOILER 19 NOX (LBNOX/MMBTU)
0.045
0.04
0.035
0.03
0.025
0.02
0.015
0.01
0.005
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018



BOILER 20 NOX (LBNOX/MMBTU)
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018

Appendix 8

Refinery fuel gas system monitoring description and permit requirements. Plat and Vac Heater SO_2 emission trends.

Alyse White

From: Mitch Colvin
Sent: Wednesday, May 30, 2018 3:24 PM
To: Amanda Metzler; Alyse White; Lance Thomasson
Subject: Fuel Gas trend

The information request from EPA for the CD inspection asks for the fuel gas H2S trend (chart) as well as the fuel gas H2S cal gas certificates. In the past, the refinery did operate an H2S CEMS on the fuel gas system. As that CEM needed to be replaced, the refinery elected to install SO2 analyzers on the #9 Plat. Htr., #4 Atm. Htr., and #4 Vac. Htr. to demonstrate compliance with fuel gas emissions. The #9 Plat. Htr. being designated as the primary analyzer. For the information request, I suggest providing the SO2 trend (chart) from the #9 Plat. Htr., as well as the cal gas certificates for the SO2 analyzer.

The refinery's Title V air permit allows for measurement of either H2S or SO2 for demonstrating compliance with the fuel gas standard.

Mitch Colvin
Delek US – El Dorado Refinery
ph. 870.864.1464
mitch.colvin@delekus.com

APPENDIX C

LIST OF CONTROLLED HEATERS , BOILERS AND COMPRESSORS

Source		Installation Deadline
#4 Pre-flash Column Reboiler (SN-803)		December 31, 2009
#4 Atm Atmospheric Furnace (S-804)		December 31, 2004
#4 Vacuum Furnace (SN-805)		December 31, 2009
#7 FCCU Furnace (SN-808)		December 31, 2009
#9 Hydrotreater Furnace/Reboiler (SN-810)		December 31, 2009
#9 Reformer Furnace (SN-811)		December 31, 2009
#10 Hydrotreater Furnace/Reboiler (SN-813)		December 31, 2009
#12 Distillate Hydrotreater Furnace (SN-842)		December 31, 2009
#10 Boiler (SN-816)	Shutdown by	December 31, 2006
#11 Boiler (SN-817)	Shutdown by	December 31, 2006
#12 Boiler (SN-818)	Shutdown by	December 31, 2006
#13 Boiler (SN-819)	Shutdown by	December 31, 2006
#14 Boiler (SN-820)	Shutdown by	December 31, 2006
New Boiler #1		December 31, 2006
New Boiler #2		December 31, 2006
New Boiler #3		December 31, 2006
G398TA Air Compressor (SN-841)		December 31, 2004
8GTL Compressor (SN-836) ("C" Compressor)		December 31, 2006

Source	NSPS Applicability Deadline
#10 Boiler (SN-816)	January 31, 2006
#11 Boiler (SN-817)	January 31, 2006
New Boiler #1	December 31, 2006
New Boiler #2	December 31, 2006
New Boiler #3	December 31, 2006
Asphalt Fume Incinerator (SN-824)	December 31, 2008

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.

PW 11. All sources specified as fuel gas combustion devices under the provisions of 40 C.F.R. § 60, Subpart J-*Standards of Performance for Petroleum Refineries* in the specific conditions of this permit are subject to the requirements outlined below: [Reg.19.304 and 40 C.F.R. § 60.100]

a. "NSPS Subpart J quality gas" or "Refinery fuel gas" is defined as any gas which is generated at a petroleum refinery and which is combusted, with the exception of gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. "Fuel gas" is defined as any gas which is generated at a petroleum refinery and which is combusted with the exception of gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. [§ 60.101(d)]

b. The permittee shall not burn fuel gas that exceeds the concentration set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Subpart J. [§ 60.104]

Table 1 – Fuel Gas Sulfur Limits

Sources	Pollutant	mg/dscm	gr/dscf	ppmvd
All refinery Fuel Gas Combustion Devices	H_2S	230	0.10	162
	SO_2	-	-	20

c. The facility shall monitor emissions and operations by installing one of the following:

i. An SO_2 CEMs on the fuel gas combustion exhaust [§ 60.105(a)(3)], or

ii. An H_2S CEMS on the fuel gas before being combusted. [§ 60.105(a)(4)]

d. Excess emissions that shall be determined and reported are defined as follows: [60.105(e)]

i. All rolling 3-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under § 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

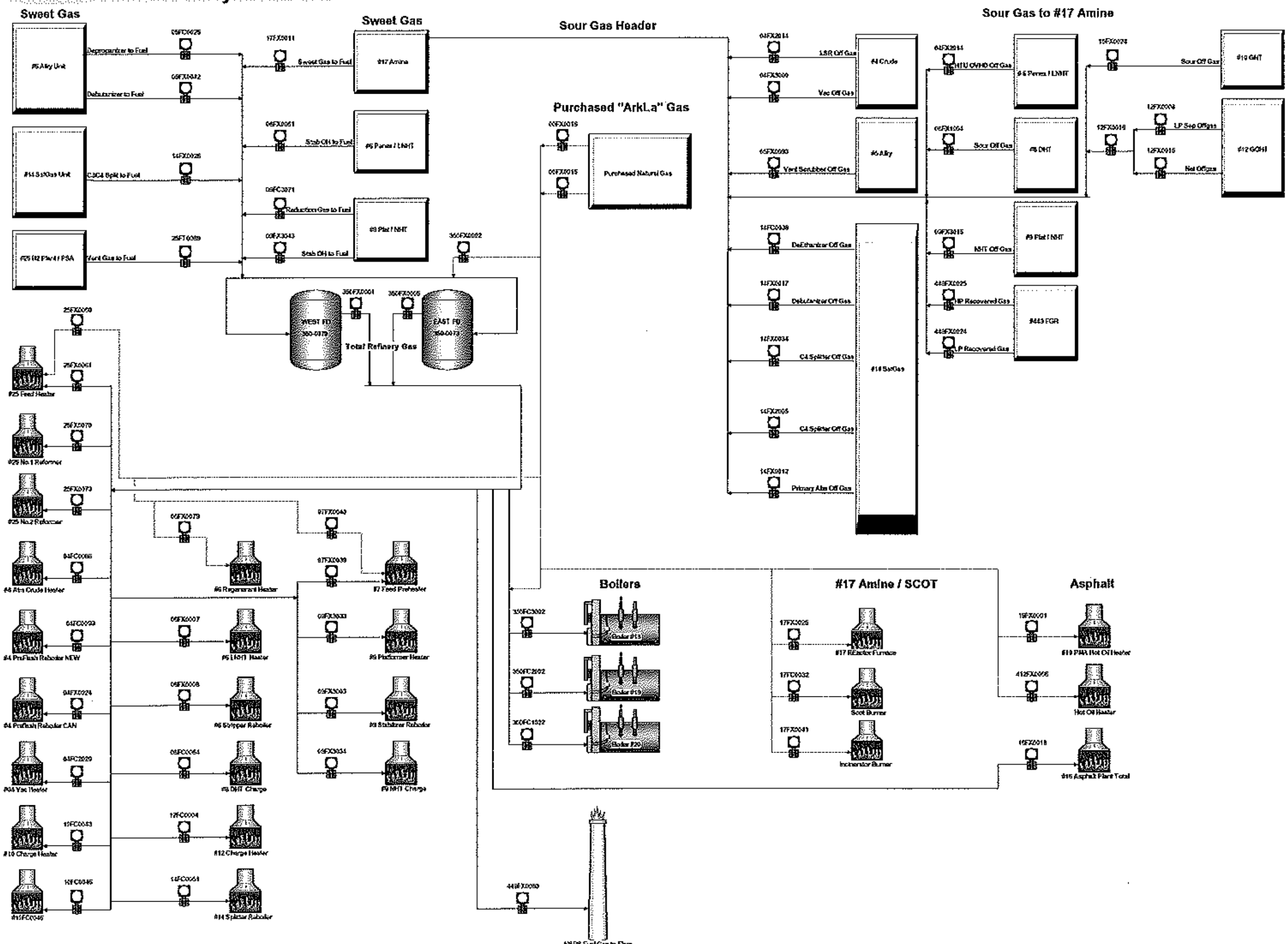
Delek US – El Dorado Refinery Fuel Gas Description

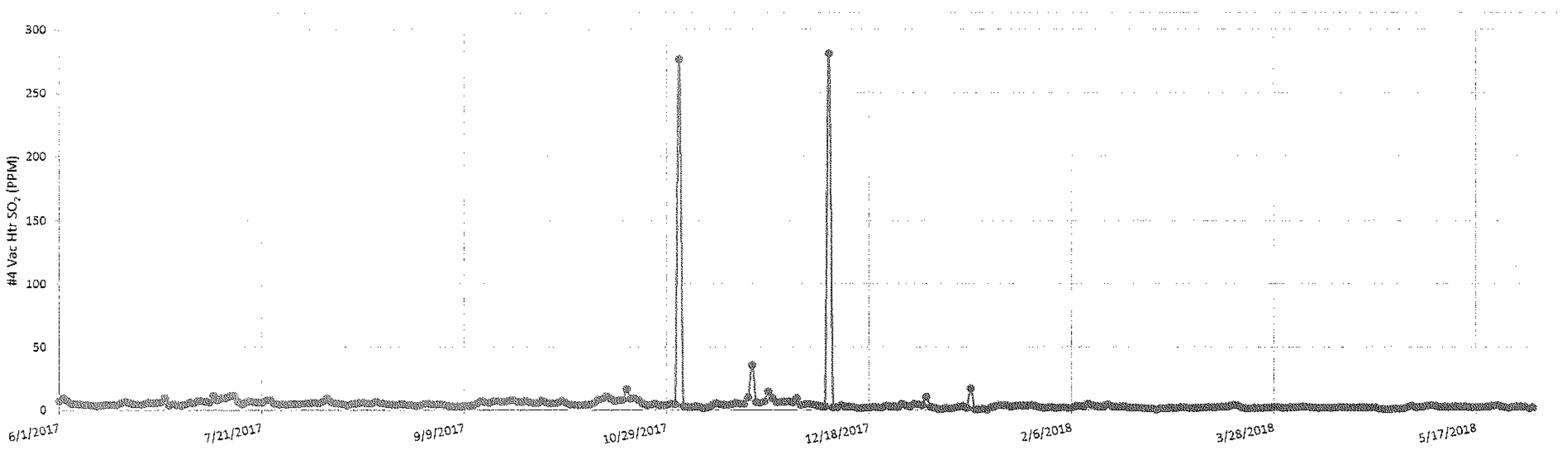
Fuel Gas System:

Various streams enter the refinery fuel gas system directly as unit off gas streams, while others are first treated in units #18 and #17 to remove hydrogen sulfide content. All of these streams combine and enter into the two fuel gas drums before being distributed to the various heaters and boilers throughout the refinery. Additionally, purchased natural gas is used in burner pilots and to maintain fuel gas supply.

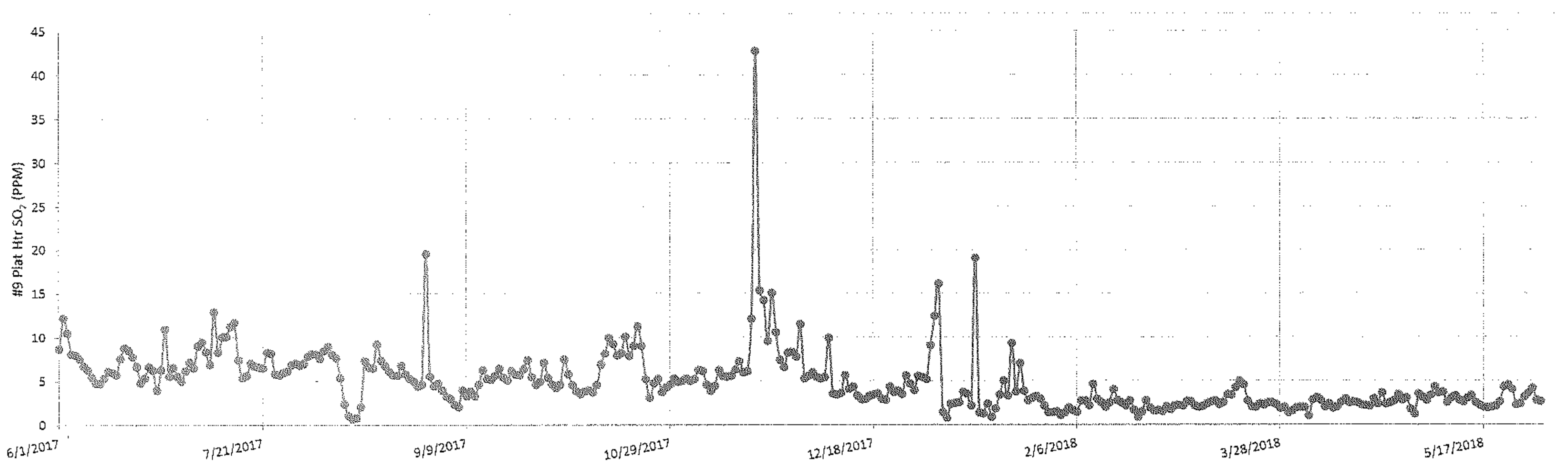
If there is a fuel gas upset it is possible to divert the excess fuel gas (NSPS) to the flare.

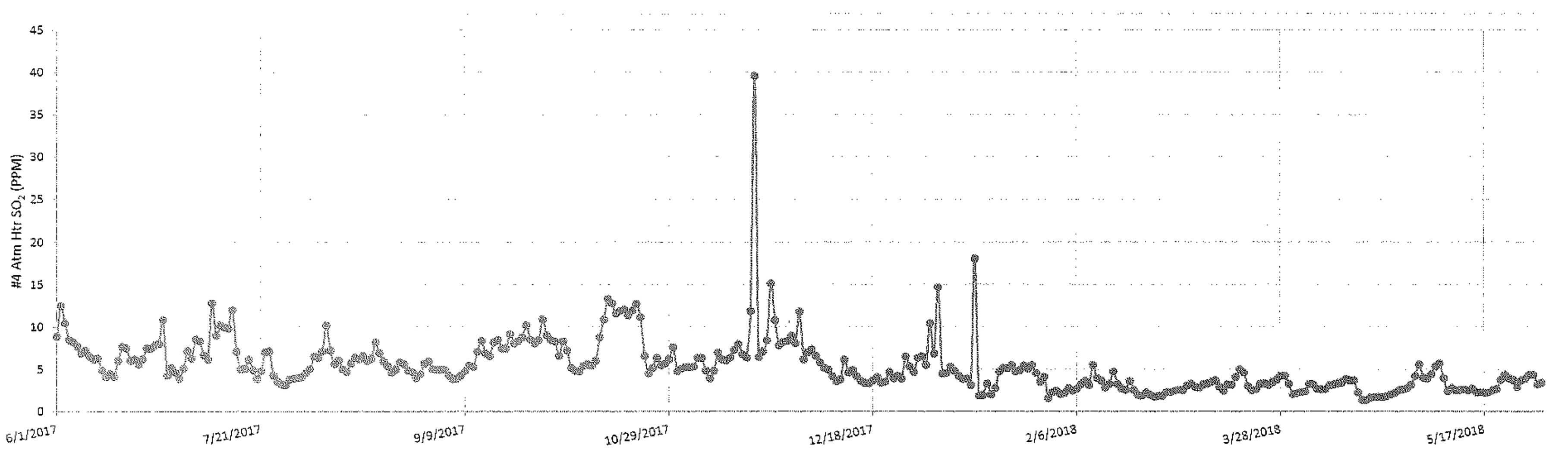
El Dorado Fuel Gas System PFD





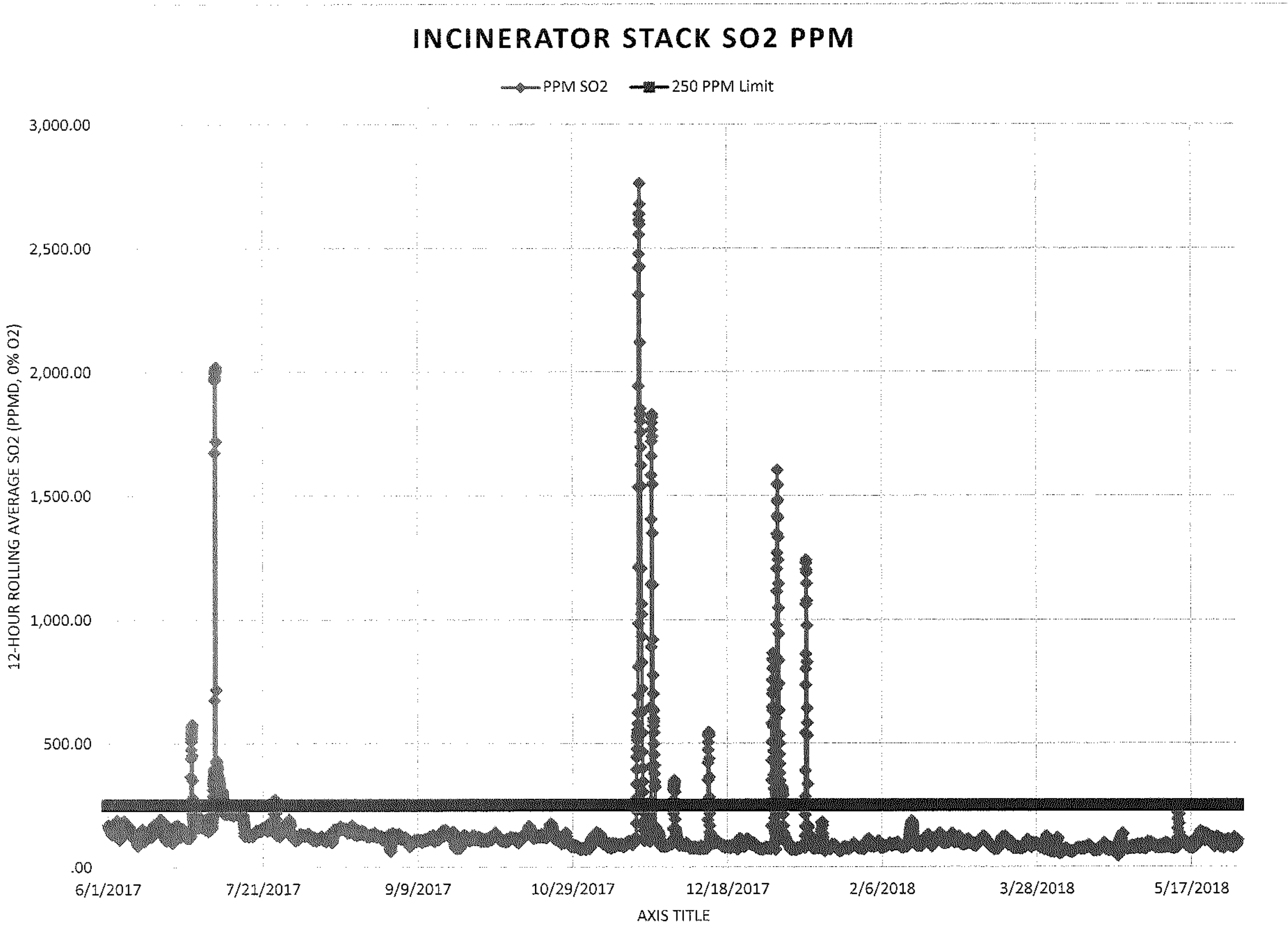
#4 Vac Htr SO_2 (PPM)
300
250
200
150
100
50
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018


#9 Plat Htr SO_2 (PPM)
0
5
10
15
20
25
30
35
40
45
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018


#4 Atm Htr SO2 (PPM)
45
40
35
30
25
20
15
10
5
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018

Appendix 9

SRP SO_2 emission trends.


INCINERATOR STACK SO2 PPM
PPM SO2
250 PPM Limit
3,000.00
2,500.00
2,000.00
1,500.00
1,000.00
500.00
.00
12-HOUR ROLLING AVERAGE SO2 (PPMD, 0% O2)
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018
AXIS TITLE

SN-844 - SRP Sulfur Recovery Plant Incinerator

Source Description

The Sulfur Recovery Plant Incinerator 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 SRP is rated at 120 long tons per day (LTD).

Specific Conditions

SRP 1 The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for SN-844 shall be demonstrated by compliance with Subpart J, the fuel and Btu limits for these sources or with other available emissions data for these sources. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
844	Sulfur Recovery Plant Incinerator	PM_{10}	12.0	52.7
		SO_2	19.1	53.4
		VOC	1.5	6.6
		CO	8.1	35.6
		NO_X	6.0	26.4

SRP 2 The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for SN-844 shall be demonstrated by compliance with Subpart J, the fuel and Btu limits for these sources or with other available emissions data for these sources. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
844	Sulfur Recovery Plant Incinerator	PM	12.0	52.7
		Ammonia	0.1	0.1
		H_2S	0.6	2.3

SRP 3 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 SO_2 emissions data recorded per Subpart J. [Reg.19.304 and 40 C.F.R. § 60.104(a)(2)(i)]

SN #	Source Description	Pollutant	ppm by volume
844	Sulfur Recovery Plant Incinerator	SO_2 dry basis	250 (Rolling 12-hour)

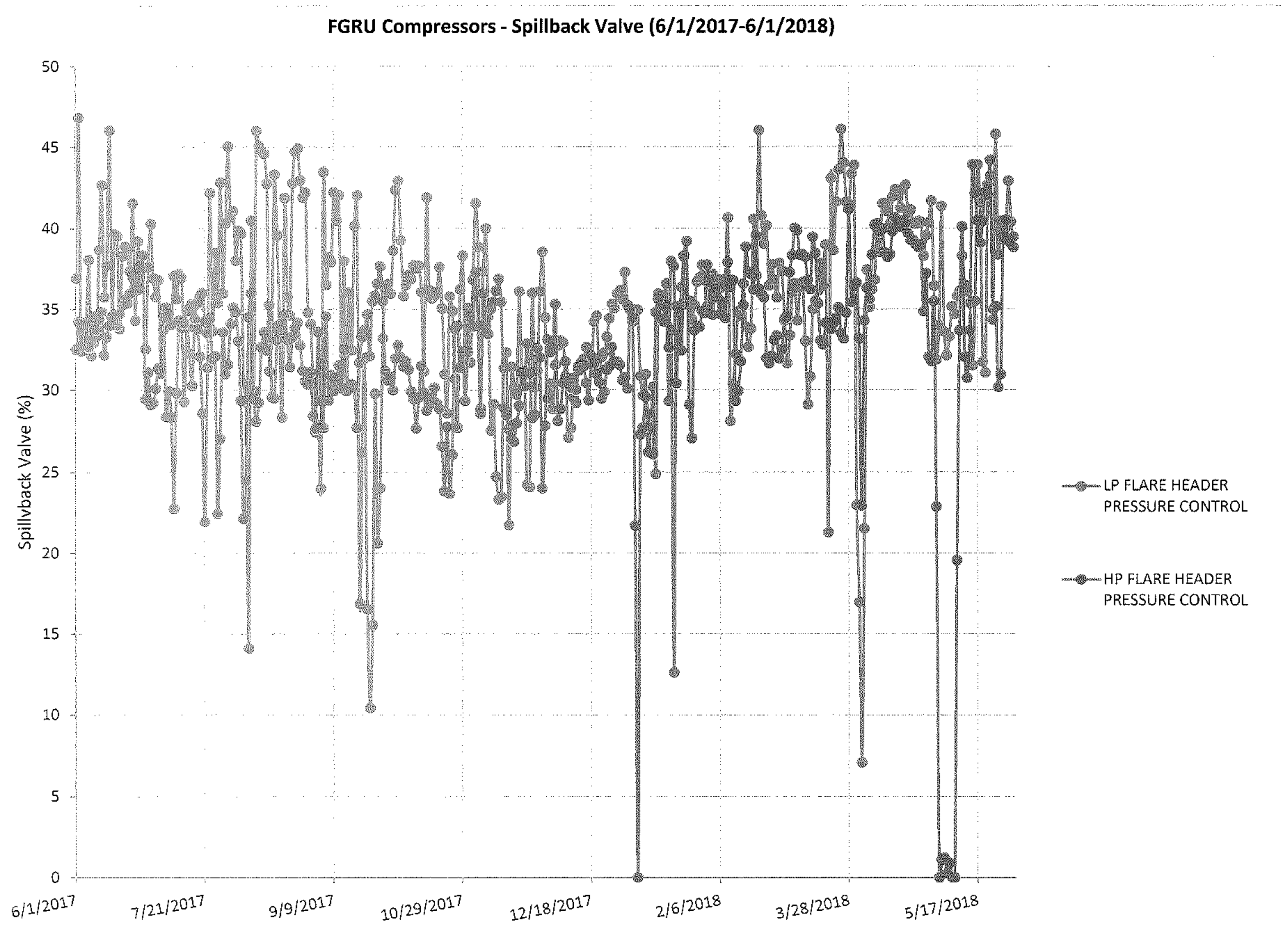
SRP 4 The facility shall use only pipeline quality natural gas as fuel for SN-844. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

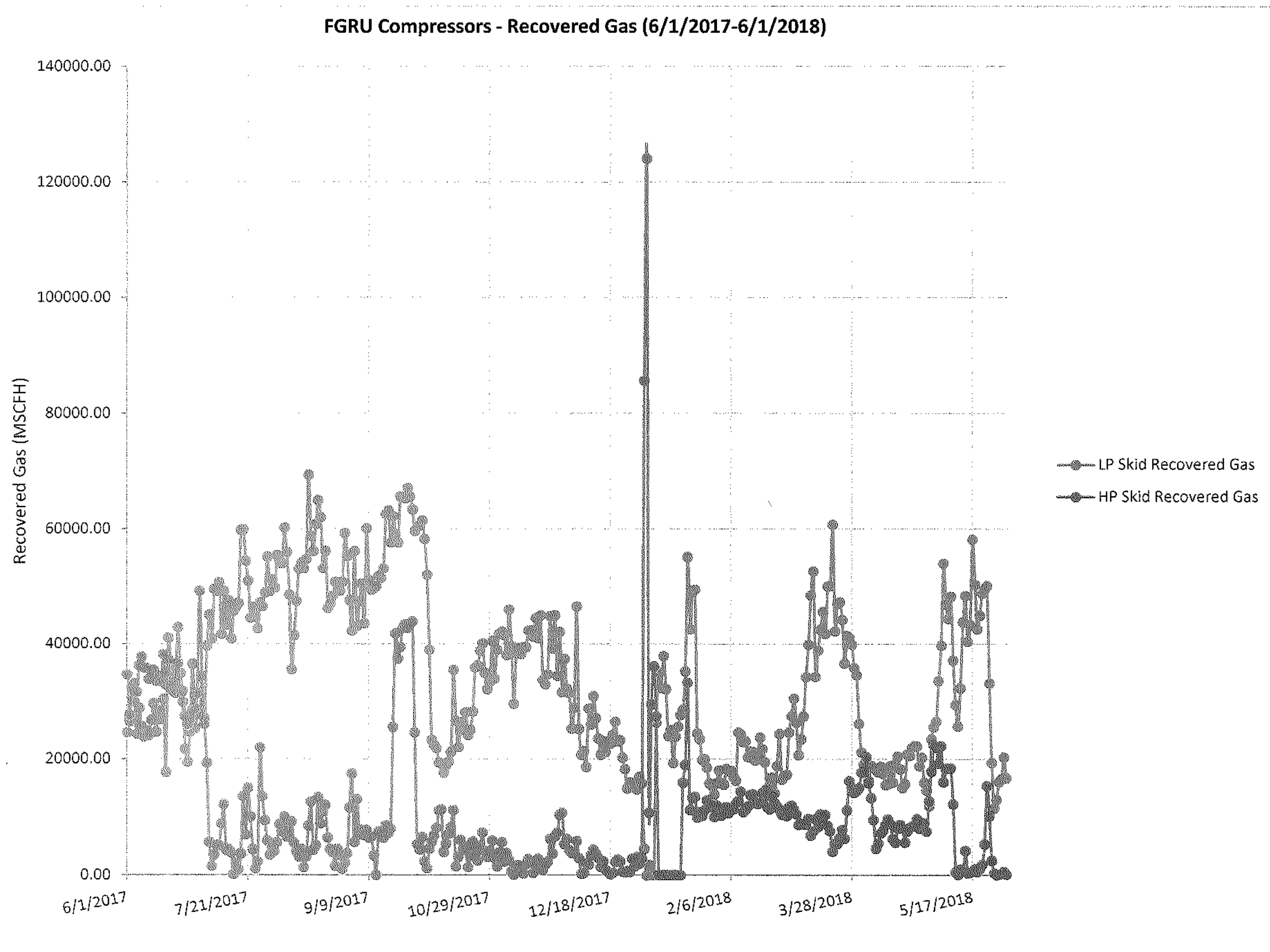
Appendix 10

Flare Gas Recovery Compressors Recorded Operation

Flare Gas Recover Unit (FGRU):

The FGRU 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 FGRU 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 FGRU, the excess gas will vent through the water seal on the FGRS to the flares.


FGRU Compressors - Spillback Valve (6/1/2017-6/1/2018)
Spillvback Valve (%)
50
45
40
35
30
25
20
15
10
5
0
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018
LP FLARE HEADER PRESSURE CONTROL
HP FLARE HEADER PRESSURE CONTROL


FGRU Compressors - Recovered Gas (6/1/2017-6/1/2018)
Recovered Gas (MSCFH)
140000.00
120000.00
100000.00
80000.00
60000.00
40000.00
20000.00
0.00
6/1/2017
7/21/2017
9/9/2017
10/29/2017
12/18/2017
2/6/2018
3/28/2018
5/17/2018
LP Skid Recovered Gas
HP Skid Recovered Gas

List of HC and Acid Gas Flaring Events: 1/1/2014-Present

Event Type	Date
HC Flaring	2/14/2014
HC Flaring	3/14/2014
HC Flaring	3/30/2014
HC Flaring	4/15/2014
HC Flaring	6/19/2014
HC Flaring	6/27/2014
HC Flaring	8/23/2014
HC Flaring	9/19/2014
HC Flaring	3/12/2015
HC Flaring	8/12/2015
HC Flaring	10/5/2015
HC Flaring	7/8/2016
HC Flaring	7/4/2017
HC Flaring	10/22/2017
HC Flaring	1/1/2018
HC Flaring	3/20/2018

Appendix 11

BWON Diagrams, Flash Separator Operation

BWON Process Description

Benzene-containing waste streams are collected and managed primarily in below-ground sewers. The wastewater management system at the refinery consists of individual drain systems, oil/water separators, storage tanks, and a biodegradation unit.

The Refinery's wastewater system brings streams from a variety of sources to two Equalization Tanks, which feed the wastewater treatment plant (WWTP) that includes dissolved gas flotation, activated sludge, and filtration. Wastewater sources are located at different regions within the Refinery, such as the process units, East tank farm, and Sand Hill area.

Wastewaters are initially managed in below-grade systems, such as drains, sewers, or sumps. Combined streams are then brought above grade into the system depicted (see benzene recovery process flow diagram), which shows the following features:

Process unit wastewaters are handled as follows:

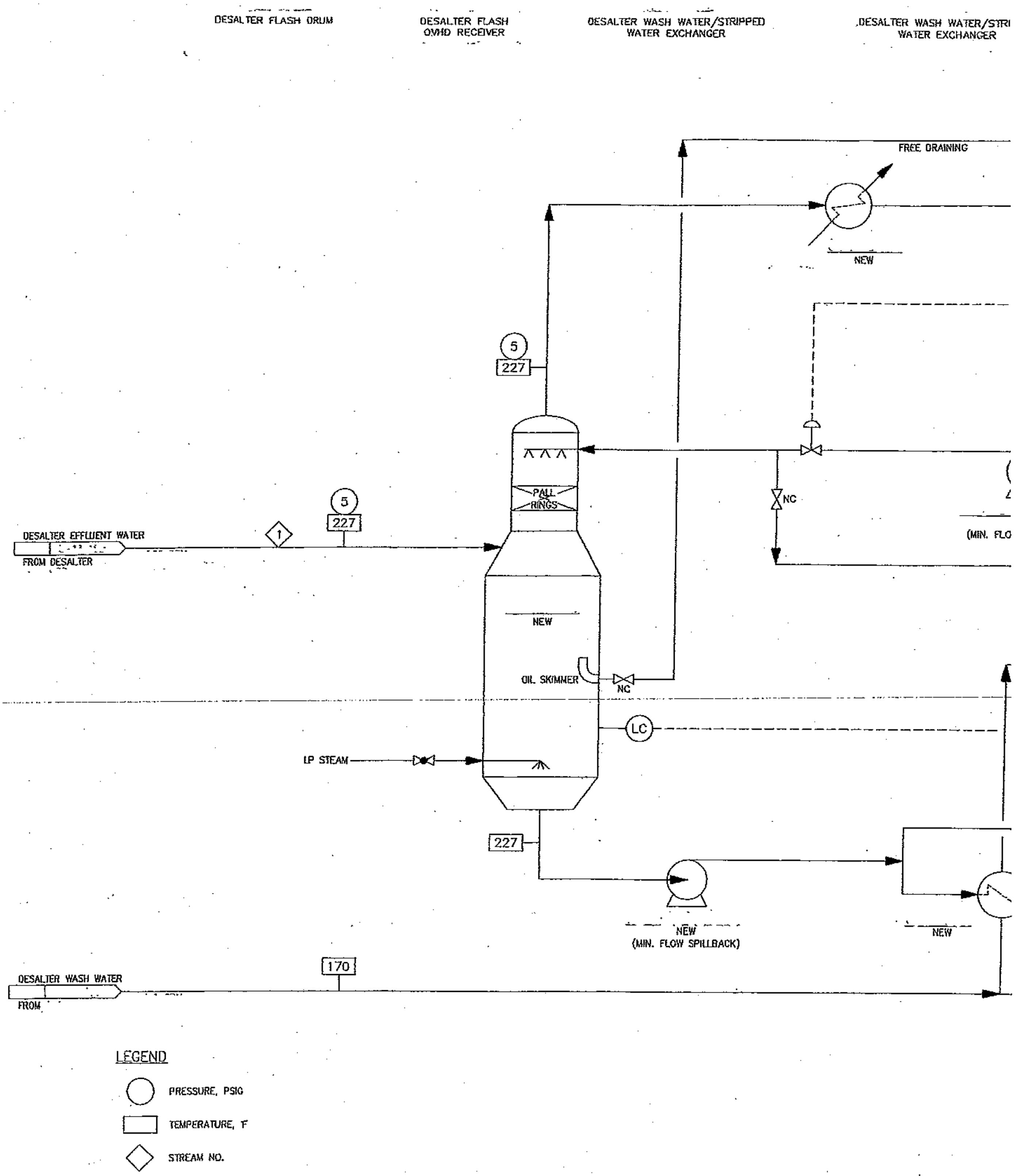
- The North Sump, an above-grade box, is fed by gravity sewers from the northern process units.
- Two North Collection Tanks receive other northern process unit wastewaters.
- Two South Collection Tanks receive wastewaters from southern process units.
- A South Sump (called the No. 8 Sump) receives some southern process unit wastewaters.

The water-phase effluents from the North Sump, North Collection Tanks, and South Collection Tanks flow through a Header that conveys flows to two Storage tanks. A number of tie-ins to the Header also bring flows from other regions to the Storage Tanks.

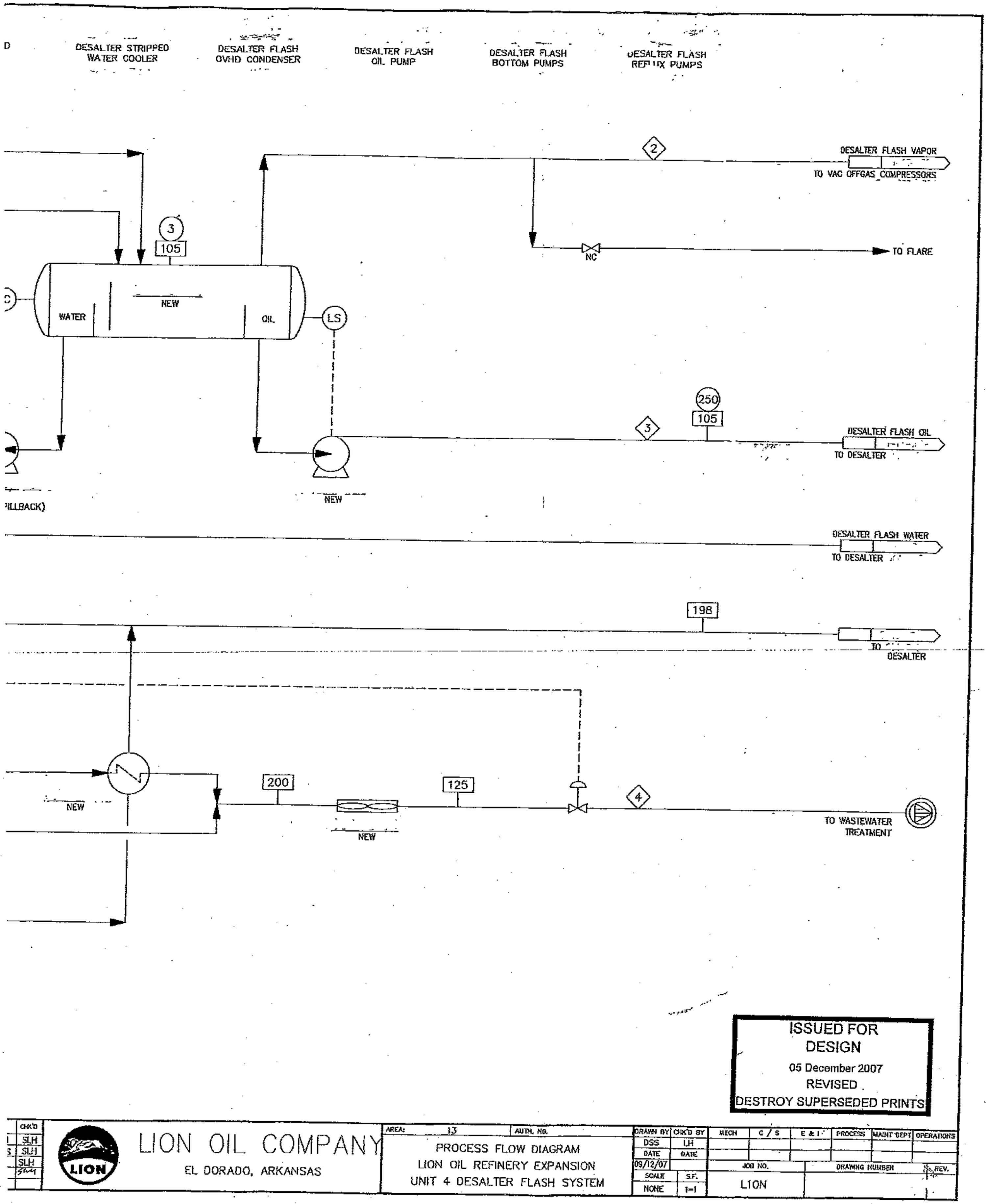
Flow from the Storage Tanks is conveyed to two Equalization tanks, which also receive flows from the API separator, return water from the Main Holding Pond, and a tie-in from the heat exchanger pad. The API separator is a wastewater management unit that predates the current above-grade wastewater system. The separator is fed primarily by runoff or other surface drainage flows.

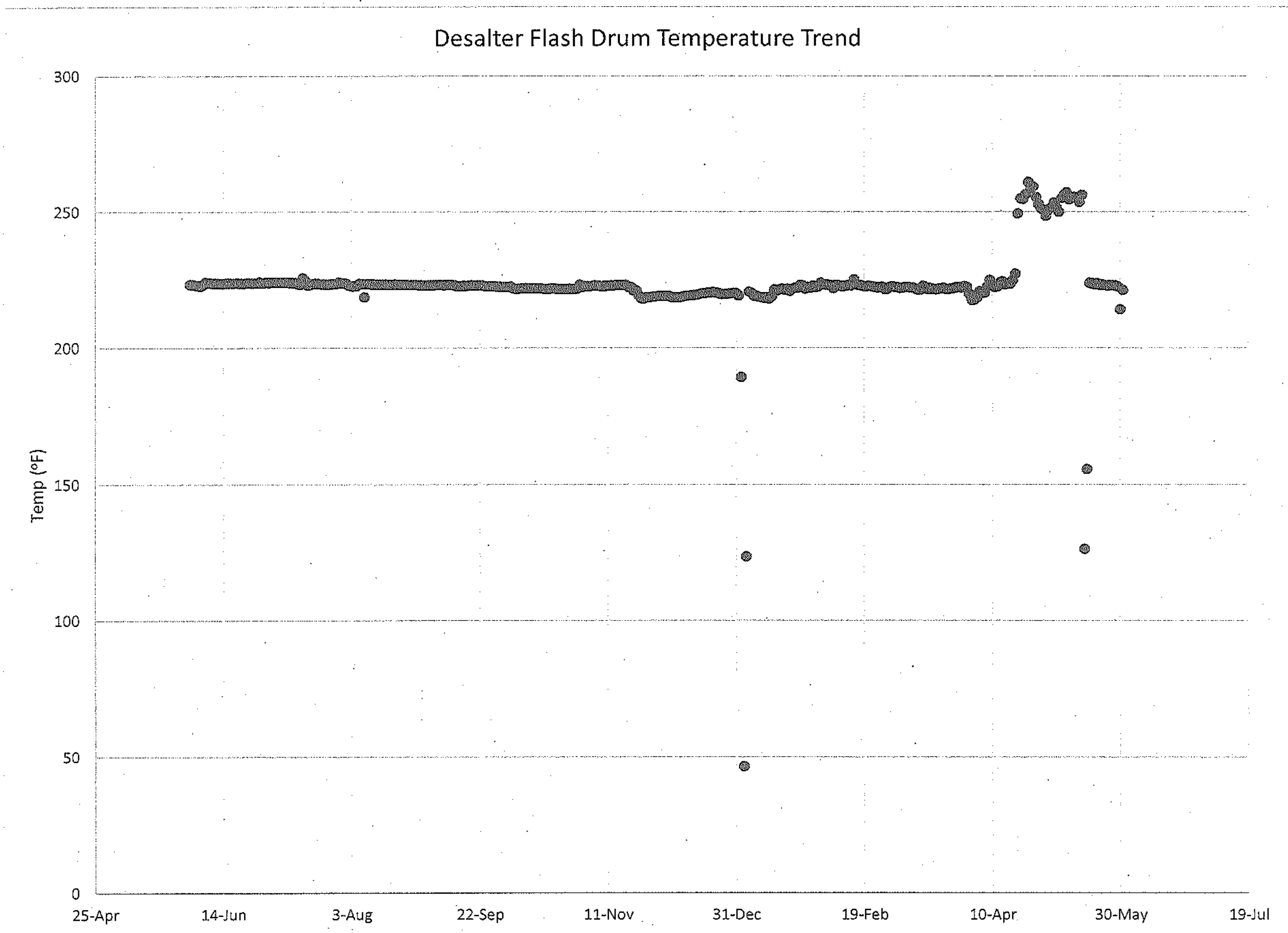
Various locations direct regional flows to the Header, with two of the largest tie-in pipes coming from the East tank farm and the Sand Hill area. The East tank farm sources are primarily tank water draws, lab discharges, and sumps with low contaminant levels (for example, sumps near boilers). The Sand Hill area has the gasoline/diesel loading rack and various tanks storing gasoline and other light (benzene-containing) hydrocarbons.

Tank_Number	Year_Built	Operating_Status	Tank Description	Service	Associated_Process_Unit	Nominal_Capacity_bbl	Nominal_Capacity_gal	Roof_Type	Diameter_ft	Shell_Height_ft
T275	2007	Active	T275 TANK S. WASTE WATER COLL TANK (E)	Oily Wastewater	WWTP	2266.14	95178.02	External Floating Roof	30	18
T276	2007	Active	T276 TANK S. WASTE WATER COLL TANK (W)	Oily Wastewater	WWTP	2266.14	95178.02	External Floating Roof	30	18
T277	2004	Active	T277 TANK N. WASTE WATER COLL TANK (E)	Oily Wastewater	WWTP	5801.33	243655.74	External Floating Roof	48	18
T278	2004	Active	T278 TANK N. WASTE WATER COLL TANK (W)	Oily Wastewater	WWTP	5801.33	243655.74	External Floating Roof	48	18
T279	2004	Active	T279 TANK WASTE WATER STORAGE TANK (E)	Oily Wastewater	WWTP	42972.79	1804857.34	External Floating Roof	80	48
T280	2004	Active	T280 TANK WASTE WATER STORAGE TANK (W	Oily Wastewater	WWTP	42972.79	1804857.34	External Floating Roof	80	48
T282	2003	Active	T282 TANK - SLOP OIL TANK (S)	Slop Oil Tank (S snow cone)	WWTP	1636.66	68739.68	Fixed Dome Roof - CVS	30	13
T283	2003	Active	T283 TANK - SLOP OIL TANK (N)	Slop Oil Tank (N snow cone)	WWTP	1636.66	68739.68	Fixed Dome Roof - CVS	30	13
T545	1991	Active	T545 TANK - EQUALIZATION TANK (E)	Oily Wastewater	WWTP	23640.63	992906.55	External Floating Roof	65	40
T546	1991	Active	T546 TANK - EQUALIZATION TANK (W)	Oily Wastewater	WWTP	23640.63	992906.55	External Floating Roof	65	40
T547	1991	Active	T547 TANK- SOUR H2O TK (water draw collection Tank for Sandhill Tanks)	Water - Water Draw Tank	Pumphouse	168.00	7050.00	Fixex Roof - < 10,000 gal	10	12

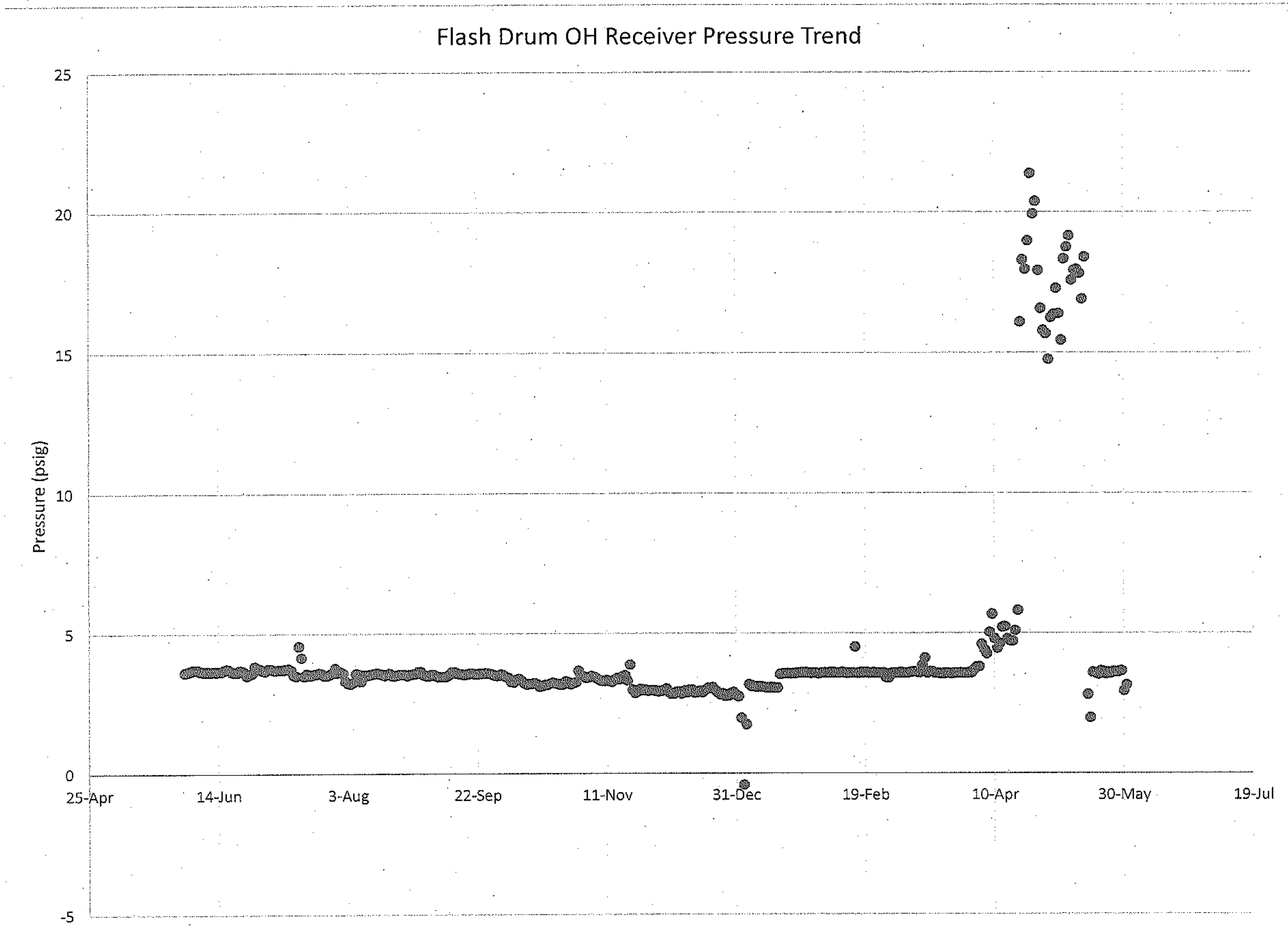


REFERENCE DRAWINGS	REV	DATE	DESCRIPTION
	A	08/17/07	ISSUED FOR JOINT REVIEW
	0	09/26/07	ISSUED FOR DESIGN
	1	10/30/07	RE-ISSUED FOR DESIGN
	1A	11/20/07	RE-ISSUED FOR DESIGN


DESALTER STRIPPED WATER COOLER
DESALTER FLASH OVHD CONDENSER
DESALTER FLASH OIL PUMP
DESALTER FLASH BOTTOM PUMPS
DESALTER FLASH REFLUX PUMPS
DESALTER FLASH VAPOR
TO VAC OFFGAS COMPRESSORS
TO FLARE
NC
3
105
NEW
WATER
OIL
LS
250
105
DESALTER FLASH OIL
TO DESALTER
NEW
DESALTER FLASH WATER
TO DESALTER
198
TO DESALTER
200
125
NEW
NEW
TO WASTEWATER TREATMENT
ISSUED FOR DESIGN
05 December 2007
REVISED
DESTROY SUPERSEDED PRINTS
LION OIL COMPANY
EL DORADO, ARKANSAS
AREA: 13
AUTH. NO.
PROCESS FLOW DIAGRAM
LION OIL REFINERY EXPANSION
UNIT 4 DESALTER FLASH SYSTEM
DRAWN BY DSS
CHK'D BY LH
DATE 09/12/07
SCALE NONE
S.F. 1=1
JOB NO. LION
DRAWING NUMBER
REV.
MECH
C / S
E & I
PROCESS
MAINT DEPT
OPERATIONS
CHK'D SLH SLH SLH

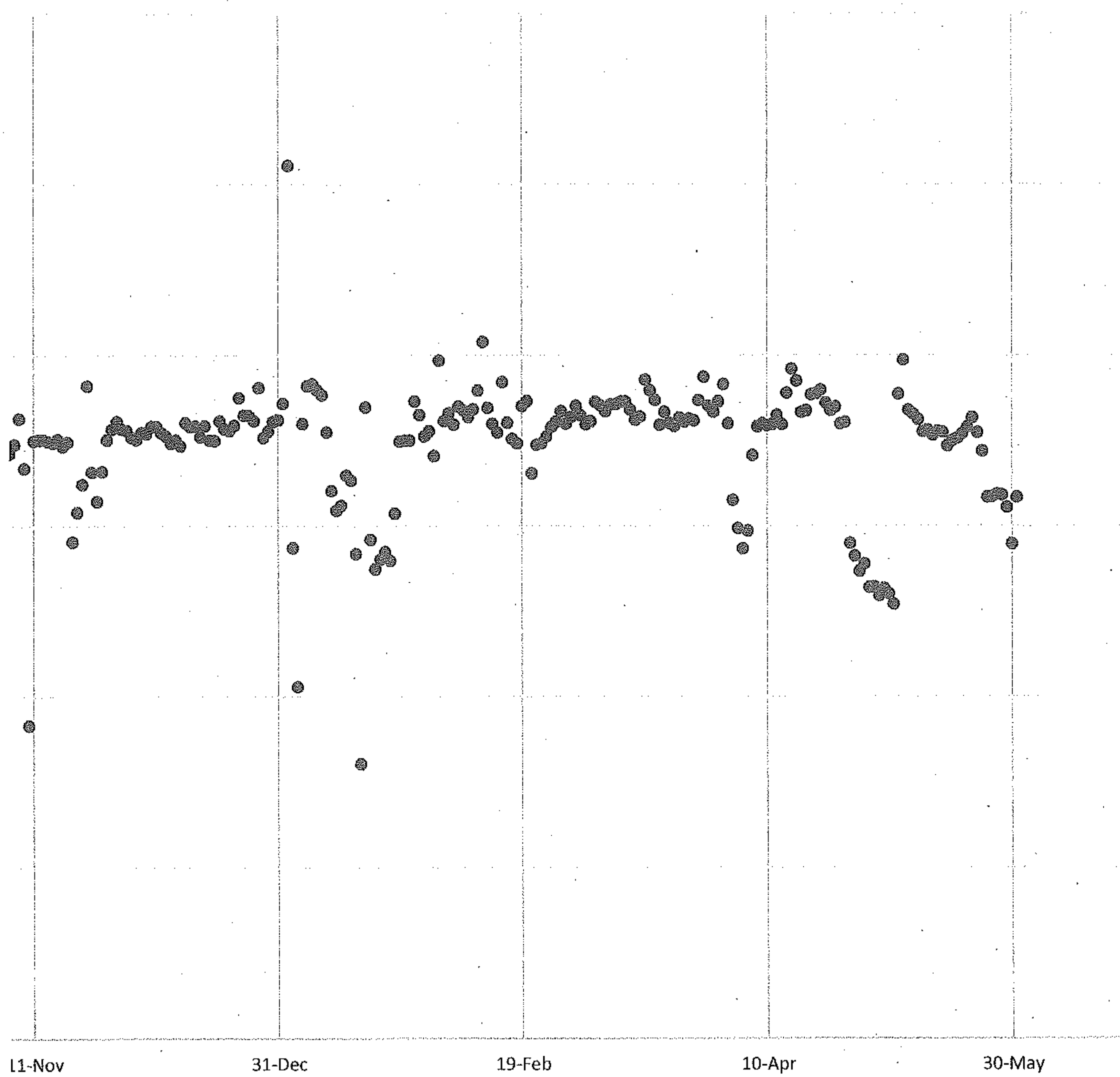


Desalter Flash Drum Temperature Trend
Temp (°F)
300
250
200
150
100
50
0
25-Apr
14-Jun
3-Aug
22-Sep
11-Nov
31-Dec
19-Feb
10-Apr
30-May
19-Jul



Flash Drum OH Receiver Pressure Trend
Pressure (psig)
25
20
15
10
5
0
-5
25-Apr
14-Jun
3-Aug
22-Sep
11-Nov
31-Dec
19-Feb
10-Apr
30-May
19-Jul

ı Separator Flow Trend



Appendix 12

Operating Permits Excerpts.

ADEQ OPERATING AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0868-AOP-R13

IS ISSUED TO:

Lion Oil Company
1000 McHenry Drive
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:

August 31, 2016 AND August 30, 2021

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Stuart Spencer
Associate Director, Office of Air Quality

APR 20 2017
Date

FHR 8. The permittee shall operate the #4 Atmospheric Furnace, SN-804, and the #9 Reformer furnace, SN-811, such that NO_x emissions to the atmosphere do not exceed 0.045 lb/MMBtu based on a 3-hour average. [Reg.19.501, Reg.19.901, 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of the consent agreement between Lion Oil, the US EPA, and ADEQ]

FHR 9. The permittee shall operate SN-803, SN-805, SN-808, SN-810, and SN-842 such that NO_x emissions to the atmosphere do not exceed 0.035 lb/MMBtu based on a 3 hour average. [Reg.19.901, 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of Consent Decree (Civ No. 03-0128)]

FHR 10. The permittee shall demonstrate compliance with the NO_x limits for SN-803, SN-805, SN-808, SN-810, and SN-842 by installing and operating a continuous parameter monitoring system to monitor oxygen concentration in the stack for each heater. The oxygen monitoring system shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter. Lion shall maintain a 3-hour rolling average oxygen concentration between 2% and 7%. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of Consent Decree (Civ No. 03-0128)]

FHR 11. The permittee shall install, certify, calibrate, maintain and operate a CEM system in the SN-811 exhaust stack for the purpose of monitoring NO_x emissions. The data from this monitor shall be recorded and compiled in order to demonstrate compliance with the NO_x limit in Specific Condition FHR 8. The CEM shall be operated in accordance with the Department's CEM Conditions, §60.11, §60.13, and appendices A, B, and F. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E and Paragraph 16(D) of Consent Decree (Civ No. 03-0128)]

FHR 12. The permittee shall install, certify, calibrate, maintain and operate a CEM system in the #4 Atmospheric Furnace, SN-804, exhaust stack for the purposes of monitoring NO_x emissions. The data from this monitor shall be recorded and compiled in order to demonstrate compliance with the 3 hour average 0.045 lb/MMBtu NO_x limit contained in Specific Condition FHR 8. The CEM shall be operated in accordance with the Department's CEM Conditions, §60.11, §60.13, and appendices A, B, and F. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of Consent Decree (Civ No. 03-0128)]

FHR 13. The permittee shall not exceed the BACT limits in the following table. Compliance with this condition is demonstrated by complying with Specific Conditions FHR 11, FHR 14, FHR 15, and the NOx CEMs required for SN-805N. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

Combustion Source	Pollutant	Control Technology	BACT Limit lb/MMBtu (3-hour average)
Current #4 Pre-Flash Column Reboiler (SN-803)	PM_{10}	Good Combustion Practice	0.0075

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. Previously permitted source, SN-848, the vent system for two storage bins used to store catalyst in the catalytic cracking process, has been routed to the wet gas scrubber of the #7 FCCU unit. 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 (CIV. No. 03-1028) reached between Lion Oil, the US EPA, and ADEQ. CEMs were installed to monitor the stack concentrations of SO_2, CO, and O_2.

BACT Review

This source underwent a BACT review for particulate and CO as a result of the refinery expansion of the 868-AOP-R5. BACT was demonstrated to be similar controls and emission limits as those defined by the Consent Decree. An additional condensable and filterable PM_{10} limit was added in 868-AOP-R9.

Specific Conditions

FCCU 1 The permittee shall not exceed the emission rates set forth in the following tables. Compliance with these limits shall be demonstrated by compliance with the throughput limits, monitoring requirements for this source or with other available emissions data for these sources. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
809	#7 Catalyst Regenerator Stack	PM_{10}	7.5	32.9
		SO_2	13.3	58.3
		VOC	4.2	18.1
		CO	116.0	101.9
		NO_x	7.7	33.5

FCCU 2 The permittee shall not exceed the emission rates set forth in the following tables. Compliance with these limits shall be demonstrated by compliance with the throughput limits, monitoring requirements for this source or with other available emissions data for these sources. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
809	#7 Catalyst Regenerator Stack	PM	7.5	32.9
		Ammonia	0.6	2.5

FCCU 3 The facility shall not exceed 20% opacity from this source. Compliance with this condition will be demonstrated by compliance with 40 C.F.R. § 60 Subpart Ja, the operation of the wet gas scrubber (WGS). [Reg.19.503 and 40 C.F.R. § 52 Subpart E]

FCCU 4 The permittee shall meet the following outlet emissions limitations. Compliance with these limits in a, c and d will be shown by FCCU 5 as applicable. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E and Paragraphs 11(B) or 11(E), 12(B), 13(B), and 14(B) of the Consent Decree (CIV. No. 03-1028) 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

iii. The SO_2 limits listed in a.i and a.ii of this Specific Condition do not apply during periods of startup and shutdown of the FCCU, and Malfunction of the either the FCCU or WGS, provided that good air pollution control practices are instituted during such events.

b. For PM:

i. No more than 0.5 pounds of filterable particulate matter (PM) per 1000 pounds of coke burned, on a 3-hour average basis except during periods of startup and shutdown of the FCCU, and Malfunction of the WGS, provided that good air pollution control practices are instituted during such events.

c. For CO:

i. 500 ppmvd corrected to 0% O_2, over a 1-hour average basis.

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

iii. The CO limits in c.i. and c.ii. of these Specific Conditions do not apply during periods of startup, shutdown, and Malfunction of the FCCU, provided that good air pollution control practices are instituted during such events.

d. For NO_x:

i. No more than 20 ppmvd based on a 365-day rolling average, corrected to 0% oxygen.

ii. No more than 40 ppmvd based on a 24-hour rolling average, corrected to 0% oxygen.

iii. The NO_x limits in i. and ii. above do not apply during periods of startup and shutdown of the FCCU, and malfunction of the Lo Tox System, provided that good air pollution practices are instituted during such events.

FCCU 5 On and after December 31, 2004, the permittee shall install, certify, calibrate, maintain and operate a NO_x CEMS, to monitor performance of the FCCU, and subsequently, the Lo Tox System, and SO_2, CO, and O_2 and to report compliance with the terms and conditions of the Consent Decree (CIV. No. 03-1028), as applicable. The CEM shall be operated in accordance with the Department's CEM Conditions, §60.11, §60.13, and appendices A, B, and F. [Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA]

FCCU 6 The FCCU is an affected facility under the terms of 40 C.F.R. § 60 Subpart Ja. The requirements of this subpart as they apply to this source are summarized below. [Reg.19.304 and 40 C.F.R. § 60.100a]

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 1.0 lb/ton of coke burn-off in the catalyst regenerator. [§ 60.102a(b)(1)(i)]

b. 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, dry basis corrected to 0 percent excess air, on an hourly average basis. [§ 60.102a(b)(4)]

c. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain SO_2 in excess of 50 ppmvd, dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis. [§ 60.102a(b)(3)]

d. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain NO_x in excess of 80 ppmvd, dry basis corrected to 0 percent excess air, on a 7-day rolling average basis. [§ 60.102a(b)(2)]

e. As the permittee uses a continuous parameter monitoring system (CPMS) on a wet scrubber, the permittee shall comply with the following control device parameter operating limits.

i. The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

ii. The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test. [§ 60.102a(c)]

f. The permittee shall conduct testing of the #7 FCCU Catalyst Regenerator Stack (SN-809) to show compliance with the PM limit in §60.102a(b). This testing shall be conducted at least once every twelve months. These tests shall be conducted in accordance with Plantwide Condition 3 and as specified below.

i. The permittee shall use EPA Reference Method 5 or 5B to determine the PM emission from the #7 FCCU Catalyst Regenerator Stack (SN-809).

SN-821a, 821b, 821c - Refinery Boilers (Three Boilers)

Source Description

Three refinery boilers were installed at the facility as part of the boiler replacement project required by the Consent Decree (CIV. No. 03-1028) reached between Lion Oil, ADEQ, and the US EPA. The total rated heat input capacity for all three boilers are 605 MMBtu/hr on an annual average basis. Individually the boilers each operate at a maximum of 221.8 MMBtu/hr for a total maximum heat input capacity of 665.5 MM Btu/hr. These boilers are permitted to burn NSPS Subpart J quality gas, or #2 fuel oil. Each of the boilers utilizes next-generation ultra-low-NO_x burners for NO_x emission control.

Regulations

All three of the refinery boilers are subject to each of the following regulations: 40 C.F.R. § 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 C.F.R. § 60 Subpart J – Standards of Performance for Petroleum Refineries.

The emission limitations established for this source were relied upon in a PSD netting analysis. Future increases in these permitted levels may trigger PSD review for these sources.

Specific Conditions

BOI 1 The listed sources shall not exceed the emission rates set forth in the following table. The limits given in this table represent the combined emissions from all three boiler exhaust stacks. Compliance with these limits shall be demonstrated by compliance with Specific Conditions #BOI 2, #BOI 6, #BOI 7, #BOI 8, #BOI 10 #BOI 12, #BOI 13 or with other available emissions data for these sources. The emission rates in the table below for #2 fuel oil combustion do not allow for the facility to make modifications in order to combust fuel oil. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Source Description	Pollutant	lb/hr	tpy
821	Three Boilers - burning NSPS Subpart J quality gas	PM_{10}	7.8	---
		SO_2	22.4	---
		VOC	9.8	---
		CO	474.2	---
		NO_X	23.3	---
821	Three boilers – burning #2 fuel oil	PM_{10}	15.7	---
		SO_2	37.3	---
		VOC	20.0	---
		CO	474.2	---
		NO_X	66.6	---

BOI 7 The facility shall not exceed 20% opacity from the refinery boilers (SN-821a, b, or c) when burning fuel oil. Compliance with this condition shall be demonstrated by The COMs data in condition BOI 13c. [Reg.19.503 and 40 C.F.R. § 52 Subpart E]

BOI 8 The facility shall use only pipeline quality natural gas or NSPS Subpart J quality gas as fuel for the refinery boilers (SN-821). 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. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

BOI 9 The permittee shall not exceed an NO_x emission rate of 0.035 lb/MMBtu based on a rolling 3-hour average from any of the three refinery boilers (SN-821a, 821b and 821c). [Reg.19.501, 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of the consent agreement between Lion Oil, the US EPA, and ADEQ]

BOI 10 In the event that fuel oil is used at this source, the facility shall maintain monthly 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 General Provision 7. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

BOI 11 The permittee shall install, operate, and maintain continuous emission monitoring (CEM) systems on each of the refinery boiler stacks (SN-821a, 821b, 821c) to monitor stack gas concentrations of CO and NO_x. These CEM systems shall comply with the Department's CEM Conditions. [Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

BOI 12 The refinery boilers (SN-821a, 821b, 821c) are subject to and shall comply with all applicable 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. The applicable requirements are summarized in Specific Condition #BOI 8 and Plantwide Condition #PW 11. [Reg.19.304 and 40 C.F.R. § 60.100]

BOI 13 The refinery boilers (SN-821a, 821b, 821c) are subject to and shall comply with all applicable requirements of 40 C.F.R. § 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The applicable requirements are summarized below. [Reg.19.304 and 40 C.F.R. § 60.40b]

a. Affected facilities which also meet the applicability requirements under Subpart J (Standards of performance for petroleum refineries; § 60.104) are subject to the particulate matter and nitrogen oxides standards under NSPS Subpart Db and the sulfur dioxide standards under subpart J (§ 60.104). [§ 60.40b(c)]

b. On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute

Source No.	Regulation	Description
ended valves or lines, valves, flanges and other connectors, product accumulator vessels, and control devices or systems		
Storage Vessels	40 C.F.R. 61, Subpart Y	None of the storage vessels contain benzene products.
Cooling Tower	40 C.F.R. 63, Subpart Q	Cooling towers have not operated with chromium-based water treatment chemicals on or after September 8, 1994.

Consent Decree (CIV. No. 03-1028) Requirements

The following conditions are required to be added to this permit by Paragraph 24 of the Consent Decree (CIV. No. 03-1028) 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.

PW 20. The heaters and boilers at Lion Oil are affected facilities, as that term is used in 40 C.F.R. Part 60 Subparts A and J, and are subject to and comply with the requirements of NSPS Subpart A and J. If there is a revision to NSPS Subpart J that excludes either certain fuel gas combustion devices or fuel gas streams from Subpart J, then that exemption shall comply to this condition as well.

PW 21. The permittee shall not burn fuel oil in any combustion unit except under the following circumstances. Fuel Oil shall mean any liquid fossil fuel with a sulfur content of greater than 0.05% by weight. Torch Oil shall mean FCCU feedstock or light cycle oil that is combusted in the FCCU regenerator to assist in starting up or restarting the FCCU. [§19.304 of Regulation 19 and 40 C.F.R. § 60.11(d)]

a. The permittee is permitted to burn torch oil in the FCCU regenerator during FCCU start-ups;

b. Lion Oil is permitted to burn Fuel Oil in combustion units after the establishment of FCCU NO_x emission limits pursuant to Paragraph 11.E. of the Consent Decree, provided that emissions from any such combustion units are routed through the FCCU Wet Gas Scrubber and Lion Oil demonstrates, with the approval of EPA, that the NO_x emission limits established therein and the SO_2 emissions limits set forth in Paragraph 12.B. of this Consent Decree will continue to be met.

c. 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 weight).

PW 22. The Sulfur Recovery Plant (SN-844) is subject to and required to comply with all applicable provisions of 40 C.F.R. § 60 (NSPS) Subparts A and J. [§19.304 of Regulation 19 and 40 C.F.R. § 60 Subparts A and J]

PW 23. The permittee shall continue to route all sulfur pit 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 C.F.R. § 60.104(a)(2)]

PW 24. 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 C.F.R. § 60.11(d)]

PW 25. The permittee shall comply with the following requirements as they relate to tail gas incidents where tail gas is 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. [§19.304 of Regulation 19 and 40 C.F.R. § 60.11(d)]

a. 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.

b. The permittee shall investigate the root cause and all contributing causes of all tail gas 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 tail gas incidents are due to malfunctions.

PW 26. 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 emission unit 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 (CIV. No. 03-1028) prior to the commencement of operations of the emissions units for which the permittee seeks to use the CD emissions reductions.

a. **General Prohibition** – The permittee shall not generate or use any NO_x, SO_2, PM, VOC, or CO emissions reductions that result from any projects conducted or controls required pursuant to the Consent Decree (CIV. No. 03-1028) as netting reductions or emissions offsets in any PSD, major non-attainment, and/or minor New Source Review (NSR) permit or permit proceeding.

b. **Exception to General Prohibition:**

i. Utilization of the exception set forth in paragraph 27.C.ii of the Consent Decree (CIV. No. 03-1028) to the general prohibition against the generation or utilization of CD emissions reductions set forth in paragraph 27.B of the Consent Decree (CIV. No. 03-1028) 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 (CIV. No. 03-1028)are for the purposes of the Consent Decree (CIV. No. 03-1028) 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 (CIV. No. 03-1028) , the permittee may use 10 tons per year of NO_x, 10 tpy of PM, and 35 tpy of SO_2 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 (CIV. No. 03-1028) (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 (2) 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 (CIV. No. 03-1028).
2. For heaters and boilers, a limit of 0.10 grains of hydrogen sulfide per dry standard cubic foot (dscf) of fuel gas or 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 NO_x or less corrected to 0% oxygen on a 365-day rolling average basis.
5. For the FCCU, a limit of 25 ppmvd SO_2 corrected to 0% oxygen on a 365-day rolling average basis.
6. For SRP's, NSPS Subpart J emission limits.

PW 27. 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 (CIV. No. 03-1028) to the extent that the proposed credits or reductions represent the difference between the emissions limitations set forth in the Consent Decree (CIV. No. 03-1028) 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 (CIV. No. 03-1028).

PW 28. By no later than December 31, 2004, Lion Oil shall install a VDU overhead recovery system on the Vacuum Distillation Tower pursuant to the terms and conditions in its October 9, 2002 submission to the Agencies. Lion has complied with this requirement by routing emissions to the Flare Gas Recovery system.

PW 29. The permittee shall submit a modification to incorporate the provisions of regulations specifically addressed in the Compliance Plan and Schedule of this permit six months before the compliance date specified in the Compliance Plan and Schedule.

PW 30. The permittee must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of 40 C.F.R. Part 63. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart. [Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]

PW 31. At all times, the permittee must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]

PW 32. The permittee shall for SN-803, SN-804, SN-805, SN-805N, SN-806, SN-808, SN-810, SN-811, SN-812, SN-813a, SN-814, SN-821a, SN-821b, SN-821c, SN-828, SN-842, SN-850, SN-857, SN-860, SN-861 East, SN-861 West, and SN-862 conduct annual tune ups. Burners part of SN-832 with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. [Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]

PW 33. The permittee must conduct an annual or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in

§ 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. [Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]

PW 34. The permittee shall for SN-803, SN-804, SN-805, SN-805N, SN-806, SN-808, SN-810, SN-811, SN-812, SN-813a, SN-814, SN-821a, SN-821b, SN-821c, SN-828, SN-832, SN-842, SN-850, SN-857, SN-860, SN-861 East, SN-861 West, and SN-862 have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:

a. A visual inspection of the boiler or process heater system.

b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.

c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.

d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.

e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.

f. A list of cost-effective energy conservation measures that are within the facility's control.

g. A list of the energy savings potential of the energy conservation measures identified.

h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
[Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]