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RON CURRY
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JON GOLDSTEIN
Deputy Secretary

CERTIFIED MAIL NO. 7005 1820 0001 5708 7944
RETURN RECEIPT REQUESTED

Permittee:

Navajo Refining Company, L.L.C.
Artesia Refinery
P.O. Box 159
Artesia, New Mexico 88211-0159

NSR Air Quality Permit No.
PSD-NM-0195-M25-R2
Artesia Refinery
TEMPO No. 198 – PRN20080002
AIRS No. 35-015-0010

Company Official:

Douglas B. Price, P.E.
Environmental Manager for Air Quality

M. A. Uhl
Mary Uhl
Bureau Chief
Air Quality Bureau

5/14/08
Date of Issuance

This permit is not effective until the Department receives the permit fee of $18,772 as specified on the attached invoice. Please note that this permit fee is due regardless of the intended use or non-use of the permit or cancellation of the permit by the applicant or Department.

Air Quality Permit No. **PSD-NM-0195-M25-R2** is issued by the Air Quality Bureau of the New Mexico Environment Department (Department) to Navajo Refining Company, L.L.C. pursuant to the Air Quality Control Act (Act) and regulations adopted pursuant to the Act including Title 20, Chapter 2, Part 72 of the New Mexico Administrative Code (NMAC), (20.2.72 NMAC), Construction Permits and is enforceable pursuant to the Act and the air quality control regulations applicable to this source.

This permit authorizes the construction/modification and operation of the **Artesia Refinery**. The function of the facility is to process crude oil and petroleum distillates into petroleum products such as diesel, gasoline and aviation fuel. This facility is located within the City limits of Artesia, in Township 17S, Range 26E, Section 9, in Eddy County, New Mexico.

This revision consists of the following:

1. Updating the location, dimensions, and deck fitting component count for proposed naphtha tank NAP-TK and renumbering this tank as T-1225;
2. Relocating, revising dimensions, and revising the permitted throughput of the proposed pitch tanks PITCH-TK1 and PITCH-TK2, renumbering PITCH-TK1 as T-1227, and adding a new pitch tank, PITCH-TK3;
3. Correcting the column diameter and rim seal loss factors for tank T-56;
4. Constructing one 50,000 bbl and one 80,000 bbl external floating roof storage tanks and associated components in lieu of the two proposed 90,000 bbl tanks authorized by 0195-M19;
5. Retrofitting heater H-600 with next generation ultra-low NO_X burners as required by the Consent Decree;
6. Correcting a typographical error in the CO and VOC emission rates for cooling tower CTY-8;
7. Adding VOC allowable emission rates for all combustion sources listed in Table 1 - Allowable Emission Limits;
8. Revising all emission rate tables to show rounding to the nearest tenth instead of the nearest hundredth;
9. Relocating three proposed process units (ROSE2, Hydrocracker, and Hydrogen Plant 2); and
10. Relocation existing tank T-437.

This permit supersedes all portions of Air Quality Permit No. **PSD-NM-0195-M25**, issued December 14, 2007, except the portion requiring compliance tests. Compliance test conditions from previous permits are still in effect, in addition to compliance test requirements contained in this permit.

The Department has reviewed the permit application for the proposed revision and has determined that the provisions of the Act and ambient air quality standards will be met. Conditions have been imposed in this permit to assure continued compliance. 20.2.72.210.D NMAC, states that any term or condition imposed by the Department on a permit is enforceable to the same extent as a regulation of the Environmental Improvement Board.

Pursuant to 20.2.75.11 NMAC, the Department will assess an annual fee for this facility. This regulation set the fee amount at $1,500 through 2004 and requires it to be adjusted annually for the Consumer Price Index on January 1. The current fee amount is available by contacting the Department or can be found on the Department's website. The AQB will invoice the permittee for the annual fee amount at the beginning of each calendar year. This fee does not apply to sources which are assessed an annual fee in accordance with 20.2.71 NMAC. For sources that satisfy the definition of "small business" in 20.2.75.7.F NMAC, this annual fee will be divided by two.

All fees shall be remitted in the form of a corporate check, certified check, or money order made payable to the "NM Environment Department, AQB" mailed to the address shown on the invoice and shall be accompanied by the remittance slip attached to the invoice.

TOTAL EMISSIONS

The total potential emissions from this facility, excluding exempted activities, are shown in the following table. Emission limitations for individual units are shown in Specific Condition 2.

Total Potential Criteria Pollutant Emissions from Entire Facility (for information only, not an enforceable condition):

Pollutant	**Emissions** (tons per year)
Nitrogen Oxides (NOx)	673.1
Carbon Monoxide (CO)	1139.0
Volatile Organic Compounds (VOC)*	1567.4
Sulfur Dioxide (SO_2)	342.1
Particulate Matter – total suspended (TSP)	189.6
Particulate Matter less than 10 microns (PM_{10})	189.6
Particulate Matter less than 10 microns ($PM_{2.5}$)	189.6
Hydrogen Sulfide (H_2S) (NMAAQ)	7

*The VOC total includes permitted Maintenance, Startup, and Shutdown (MSS) emissions from Table 3 of this permit.

Total Potential HAPS that exceed 0.5 ton per year (for information only, not an enforceable condition):

Pollutant	**Emissions** (tons per year)
Hexane	6.3
Benzene	6.6
Total HAP	25

Table A: Artesia Refinery Permit History

Permit Number	**Date Issued**	**Description**

Permit Number	Date Issued	Description
31	August 20, 1973	Construction of 1000 Barrel per Day Cycle Oil Hydrodesulfurizer (HDS)
80	November 14, 1975 Construction	of Naphtha HDS Unit and a Powerformer Catalytic Reformer
155	November 16, 1977	Boilers B-1, B-2, B-3, B-4, and Heater H-20 for Optional Combustion of Fuel Oil or Fuel Gas
195	May 22, 1978	Construction of a 108,000 Barrel Crude Oil Storage Tank
236	May 2, 1979	Replacement of an Existing Thermofor Catalytic Cracking Unit (TCCU) with a Fluid Catalytic Cracking Unit (FCCU). No permit required, file no. 236, and permit No. PSD-NM-208, later rescinded
PSD-NM-208	July 19, 1979	PSD Permit (Rescinded Nov. 9, 1981)
195-M-1	November 29, 1982	Construction of Two 55,000 Barrel Floating Roof Hydrocarbon Storage Tanks. Permit No. 195-M-1
195-M-2	August 28, 1990	Construction of the Continuous Catalyst Regeneration (CCR) Reformer and Expansion of the Naphtha HDS Unit
195-M-3	March 14, 1991	Installing a 6700 Barrel per Day Alkylation Unit and Supporting Equipment
195-M-4	January 16, 1992	20-Long-Ton-Per-Day Sulfur Recovery Unit (SRU) and Supporting Equipment
195-M-5 195-M-5-Rev	November 25, 1992 December 16, 1993	Relocation of Diesel HDS Unit and Associated SRU Upgrade Project
195-M-6	March 13, 1996	Powerformer/Penex Project
195-M-7	September 4, 1997	Wastewater Treatment Plant Upgrade, Changes in Supplemental Heat for Flare FL-403, Changes in Throughput and Vapor Pressure for Material Stored in Tank T-450, Construction of a tail gas cleanup unit and auxiliary blower for the SRU
195-M-8	Records are between the dates for 195-M-5-Rev & 195-M-6	Withdrawn requests for changes to 195-M-5-Rev that included CCR Reformer Project, North Alkylation Unit, Flare FL-403, and Naphtha HDS and Sulfur Recovery Upgrade (FL-400)

Permit Number	Date Issued	Description
195-M-9	May 5, 1998	Replacement of Boiler B-3 (58.0 MMBTU/hr) with Boiler B-6 (43 MMBTU/hr)

Permit Number	Date Issued	Affected Conditions	Description
195-M-9-R-1	October 13, 1998	1.N (new)	Replacing LPG tanks
195-M-9-R-2	January 11, 1999	1.O, 4.K (new)	New LDMAR – North Plant Amine Treating/Regeneration
195-M-9-R-3	October 13, 1999	1.O (new)	New Polymer Modified Asphalt
195-M-10	January 7, 2000	9.A.(1-6, 10, 12, 13) (removed), 2.C, 2.D, 4.D, 8.C, Table 1 (modified)	Increase SRU/TGU (H463) capacity to 40 LT/D
195-M-10-R-1	Feb. 18, 2000 Permit not issued	Did not quality for technical revision under 2.72,219.B.1.b	Technical Revision to increase Heater H40 (H463) capacity and allowable emissions
195-M-11	Application received June 29, 1999, ruled incomplete July 28, 1999 Permit not issued	Modification would subject to PSD review.	Application for Gas Oil Hydrotreater (GOHT) and FCCU expansion. Subject to PSD review, application not reviewed, permit not issued.
195-M-12	May 11, 2000	1.P (new), 2.C, 3.B, 4.B, 4.C, 4.D, 4.E, 5.B, 5.F, 7.A, 7.B, 8.C, 9.A, 9.B, Table 1 (modified)	New 100 LT/D SRU2/TGU2
195-M-13	August 30, 2000	1.Q (new), 1.P, 1.L.a.1, 8.O, Table 2.A, Table 2.D (modified)	New No. 3 Blender, Remove KES/SOLSEP from WWTP

Permit Number	Date Issued	Affected Conditions	Description
195-M-14	March 12, 2001	1.O, 1.P, 1.Q, 5.H, 5.I (new) 5.B, 5.E (modified)	Replaced Boilers B-1, B-2, B-4, B-6, B-103, B-104, B-105 with Boilers B-7, B-8. Replaced Heater H-26 with Heater H-30.
195-M-14-R1	March 15, 2001	11.A (corrected)	Corrected the SRU1/SRU2 combined SO2 emission limit.
195-M-14-R2	June 28, 2001	1.O, 3.A, 5.G, 7, Table 2B, Table 2D	Add sour water storage tank, T-802.
195-M-15	December 13, 2001	1.W (new), 2.A, 2.C, 2.W-Z (new), 3.E-F (new), 4.M-N (new), 5.D, 5.I, 5.J, 9.A, 9.B, 10.Q-R (new), Tables 1, 2A, 2B, 2C, 2D	New: GOHT Unit, H-601, ESPs (changed to scrubber) and air lift blower on FCCU, and new FL-404,. Add minor equipment to Amine Unit, CCR Unit, Diesel HDS Unit, FCCU, Naphtha HDS Unit, JP-8 HDS Unit. Upgrade tower internals on FCCU, Vacuum/Flasher Unit. Increase refinery-wide throughput; See Condition 1.W. for details.
195-M-15-R1	June 27, 2002	5.G (modified)	Administrative revision to incorporate 2 exempt gas oil storage tanks
195-M15-R2	October 22, 2003	1.X, 1.Y, 2.AA & 2.BB (all new). 3.A and Table 1.A (modified).	Installation of a 9.6 MMBTU/hr Hot Oil Heater w/CTI Low-NOx burners
195-M-16	N/A	N/A	Withdrawn per actions agreed to by Navajo and NMED. Resubmitted with M-17 application.
195-M-17	December 15, 2004	1.X-Z (new); 2.AA-QQ (new); 2.A, 2.B, 2.W, 2.Z; 3.D.3 & 4 (new); 3.G-I (new), 4.I (new); 4.M; 4O, R (new); 5.A.4 (new); 5.D, 5.G, 5.I, 5.J; 8.C; 9.A, 9.B; 10.S, 10.T (new); 11.C; 11.F (new)	Significant revision to construct an SDA Unit and to incorporate portions of the December 21, 2001 Consent Decree. Portions of the Consent Decree (Paragraphs 11 A, E, F & G, 12 A, B&D, 13 A&B, 14, 15, 16, 17, 18, A, B & C, 19, 20, A, B, D & E, 21 24 25, 26, 29, 30 & 31) were included in this application per the December 23, 2003 letter to NMED from Navajo. Portions of these Consent Decree inclusions as referred to by this permit are incorporated into this permit by reference.

Permit Number	Date Issued	Affected Conditions	Description
			This application also includes administrative changes to storage tank tables per October 3, 2002 revision request and to FL-400 acid gas flaring chart, and authorizing the operation of B-105 by requiring the unit to be retrofitted with low NOx burners.
195-M-18	February 22, 2005	1.BB & 1.CC (new); 4.A; 10.A; 11.C and Table 2.D. (modified)	Significant revision to construct an alkylate splitter and other equipment associated w/the CBG Premium Project including valves and piping to be located in the existing north and south Alky Units, and treating, blending, and tank farm areas. This equipment will allow Navajo to produce a high octane alkylate to meet gasoline specifications w/o the use of MTBE for gasoline blending.
195-M-18-R1	August 30, 2005	None	Administrative revision to incorporate exempt diesel tank T-815 (vapor pressure of tank < 0.2 psi)
195-M-19	August 22, 2005	1.DD and 2.RR (new); 4A; 5.G; 10.A; 11.C and Table(s) 2.B. and 2.D. (modified)	Significant revision to construct the Naphtha/Light Oil tanks project consisting of two new 90,000 bbl external floating roof tanks and other associated equipment including pumps, valves, and piping. This equipment will provide additional storage capacity for naphtha/light oil processed or produced by the refinery.
195-M-20	January 23, 2006	1.EE (new); 2.A, 2.C, 2.E, 2.F, 2.OO, 3.I, 4.N, 4.Q.3, 5.D,I &J, 7.B.1, 9.A, 11.A.1.b, Table 1, and Table 2.D (modified)	Significant revision to construct four new process heaters, process vessels, and other associated equipment including heat exchangers, pumps, valves, and piping and the option to modify SRU2 by enriching the O2 content in the SRU's burner/thermal reactor. This equipment will allow Navajo to produce Ultra Low Sulfur Diesel (ULSD) fuel consistent with the federal clean fuels

Permit Number	Date Issued	Affected Conditions	Description
			requirements.
195-M-21	November 18, 2005	1.FF (new); 2.OO, 3.F, 3.I.4, 4.N, 4.Q.3, 5.D, 5.I, 7.B.1, 9.A, 10.A, Table 1, and Table 2.D (modified)	Significant revision to construct one new crude oil heater (H-19) to supplement existing crude oil heater (H-20). Other new or replaced equipment includes heat exchangers, pumps, valves, and piping. The South Crude Efficiency Project will reduce energy usage or process additional crude oil at the existing heater firing rates.
195-M-22	October 13, 2005	1.GG and 7.B.1&.2 and 8.F (new); 2.OO.3, 3.I.5, 3.J, 4.N, 4.Q.2, 5.D, 5.I, 5.J, 9.A, 9.B, 10, and Table(s) 1, 2.D and 2.E (modified) 2.P (clarification); 2.X and 3.E (corrections)	Significant revision to construct a new heater, process vessels, and other associated equipment including heat exchangers, pumps, valves, and piping. The Hydrogen Plant will provide a reliable supply of hydrogen critical to the refinery's future production of low-sulfur content gasoline and will provide additional supply flexibility for hydrogen used in the refinery's hydrotreating units
M-23	Application withdrawn	Application withdrawn	Application withdrawn
195-M24	June 23, 2006	3.I.6 (new); Table 1, 2.K, 3.E.1, 10.I and 11.B.3 (modified) .	Revision to add a 3-hour rolling average NOx limit for H-20
195-M24-R1	May 18, 2007	1.HH (new), 4.A, 4.N, 5.I, 5.J, 10.A, and Table 2.D (modified)	Technical revision to add a naphtha splitter to the Unit 06 naphtha unit, resulting in an increase in fugitive components and emissions.
195-M24-R2	Application withdrawn	Application withdrawn	Application withdrawn
195-M24-R3	August 14, 2007	1. II (new)	Administrative revision to relocate existing Tank T-437.
195-M24-R4	August 31, 2007	1. JJ (new), 4.A, 4.N, 5.I,, 10.A	Technical revision for Propane Test and Release Project. Adding to new pressurized tanks and modifying several existing fugitive source areas.

Permit Number	Date Issued	Affected Conditions	Description
195-M24-R5	August 27, 2007	None	Administrative revision to change company name to Navajo Refining Company, L.L.C.
PSD-NM-195-M25	December 14, 2007	1.G.7, 1.H.1, 1.I.2, 1.I.3, 1.J.1, 1.K.1.b, 1.K.2, 1.KK (new), 2.B, 2.F, 2.X, 2.SS, 3.I, 3.J, 4.B, 4.C, 4.D, 4.E, 4.I, 4.N, 4.O, 4.P, 4.R, 4.S, 5.A, 5.B, 5.D, 5.G, 5.I, 5.J, 6.A (new) 6.B (new), 7.A (new), 7.B (new), 7.D (new), 7.E, 8.B, 8.D, 9.A, 9.B, 10.A, 11, 12.D & E, 16, Table 1; Tables 2A-2I, Table 3	Significant revision and PSD permit to expand the Artesia Refinery, including construction of the following: a Hydrocracking Unit, a Solvent De-Asphalting Unit (SDA or ROSE), a saturates gas plant, a sulfur recovery unit, a hydrogen plant, a wastewater treatment plant, a flare, a cooling tower, and associated piping, piping components, and storage tanks. Also updated emission rate calculations for all existing sources to reflect the “as-built” configurations and most appropriate emission factors.
PSD-NM-195-M25-R2	May 14, 2008	1. DD, 1.LL, 2.RR, 5.G, Tables 2B, 2D and 2F	Technical Revision applications for the construction of one 50,000 bbl and one 80,000 bbl external floating roof tanks and associated components in place of the two 90,000 bbl tanks authorized by M19 that were never constructed; a retrofit of H-600 with next-generation ultra-low NO_X burners are required by the Consent Decree; increasing the stack heights of H-600 and H-40; updating the location, dimensions and component count for naphtha tank NAP-TK that will be renumbered as T-1225; updating the location, dimensions and throughput of tanks PITCH-TK1 (to be renumbered as T-1227) and PITCH-TK2 and the construction of PITCH-TK3; correcting the column diameter and rim seal loss factors for T-56; and several administrative changes.

Federal new source performance standards (NSPS) 40 CFR 60 apply to portions of this refinery and are described in Condition 5. National emission standards for hazardous air pollutants (NESHAP) 40 CFR 61

Subparts V and FF apply to this facility. During any asbestos demolition or renovation work, 40 CFR 61 Subpart M (NESHAP) would apply. Maximum achievable control technology standards for sources of hazardous air pollutants (MACT) 40 CFR 63 Subparts R, CC, UUU, and DDDDD apply to this facility.

Conditions have been imposed in this permit to assure continued compliance. 20.2.72.210.D NMAC states that any term or condition imposed by the Department on a permit is enforceable to the same extent as a regulation of the Environmental Improvement Board. Pursuant to 20 .2.72 NMAC, the facility is subject to the following conditions:

Note: The characters within parenthesis at the end of each condition indicate the condition number of that particular condition in the version of the permit prior to reformatting i.e. Permit No. 195-M-6.

Conditions

1. Modification and Operation of the Refinery

A. Construction of a 1000 Barrel per Day Cycle Oil Hydrodesulfurizer (HDS), currently the Kerosene (JP-8) HDS. No permit required, file no. 31. (15)

This permit application, received July 30, 1973, was for the construction of a 1000 barrel per day (BBL/day) Cycle Oil Hydrodesulfurizer (HDS) designed to remove sulfur compounds from stripped cycle oil produced by the existing Thermofor Catalytic Cracking (TCC) Unit. The application requested the modification and installation of an existing asphalt heater to be used as the cycle oil furnace, associated vessels, pumps, and piping.

In accordance with Air Quality Control Regulation 702 (AQCR 702) in effect at the time, the Department ruled on August 20, 1973 that no permit was required since the Cycle Oil HDS would be a new facility rather than a modification to the basic refinery and the emissions of the new facility would be less than 10 pounds per hour and less than 25 tons per year.
This unit is now designated as the Kerosene (JP-8) HDS. The charge heater for this HDS is Heater H-26. [H-26 replaced by Heater H-30 pursuant to Permit 195-M-14]

B. Construction of a Naphtha HDS Unit and a Powerformer Catalytic Reformer. Permit No. 80.

This permit, issued November 14, 1975, allowed:

1. installing a Naphtha/Straight-Run-Gasoline HDS Unit to provide desulfurized feed for the proposed new catalytic reformer. The HDS unit would consist of a charge heater (designated H-23), associated vessels, pumps, and piping;

2. installing a Splitter Unit to preprocess the desulfurized naphtha for the Powerformer. The Splitter Unit would consist of a reboiler heater (designated H-18), a splitter tower, and

associated pumps, miscellaneous vessels, and piping;

3. installing a Powerformer catalytic reformer to convert desulfurized naphtha and desulfurized straight run gasoline into high octane gasoline blend stock. The Powerformer would consist of three reformer heaters (designated H-301, H-302, and H-304) three reactor vessels, and associated pumps, miscellaneous vessels, and piping.

C. Modification of Boilers B-1, B-2, B-3, B-4, and Heater H-20 for Optional Combustion of Fuel Oil or Fuel Gas. Permit No. 155. (16)

This permit, issued on November 16, 1977, allowed the addition of auxiliary oil gun burners to Boiler Units B-1, B-2, B-3, B-4, and Heater H-20 to provide these units the option of burning fuel oil in addition to fuel gas. [Boilers B-1, B-2, B-3, and B-4 were replaced by Boilers B-7 and B-8 pursuant to Permit No. 195-M-14. Navajo has not implemented the option to burn fuel oil in H-20]

D. Construction of a 108,000 Barrel Crude Oil Storage Tank. Permit No. 195. (17)

This permit, issued on May 22, 1978, allowed the construction of a 108,000 barrel internal floating roof crude oil storage tank, identified as tank T-439. A permit was required because uncontrolled emissions from an equivalent fixed roof tank would be more than ten pounds per hour (pph) of a regulated air contaminant. Construction of the tank was completed on November 10, 1978.

E. Replacement of an Existing Thermofor Catalytic Cracking Unit (TCCU) with a Fluid Catalytic Cracking Unit (FCCU). No permit required, file no. 236, and permit No. PSD-NM-208, later rescinded. (19)

This permit application, received on April 26, 1979, was for the replacement of an existing TCCU by a 16,000 BBL/day FCCU. In accordance with an interpretation of AQCR 702 in effect at that time, the Department ruled in a letter dated May 2, 1979 that no permit was required for the FCCU because "... an equipment exchange without increase in source emissions does not require a permit according to Permit Regulation No. 702." The FCCU went into service the week of April 24, 1981.

The U.S. Environmental Protection Agency (USEPA) issued a Prevention of Significant Deterioration (PSD) Permit No. PSD-NM-208 on July 19, 1979 allowing Navajo Refining to replace the TCCU by an FCCU with the required shutdown of the Ingersoll Rand 600 hp compressor and the TCC feed preheat furnace H-11.

EPA rescinded the PSD permit on November 9, 1981. The rescission was based on EPA's ruling that PSD regulations, as amended August 7, 1980, did not apply to this equipment replacement because the installation of the FCCU would not result in a net emissions increase of any regulated pollutant from the total refinery site, and thus the modification was not major.

F. Construction of Two 55,000 Barrel Floating Roof Hydrocarbon Storage Tanks. Permit No. 195-M-1. (18)

This permit modification, issued on November 29, 1982, allowed the construction of two 55,000 barrel external floating roof hydrocarbon storage tanks, identified as tanks T-401 and T-402.

These tanks were constructed and are operated in accordance with the application dated September 27, 1982. Tank T-401 was placed in service on March 13, 1983 and Tank T-402 was placed in service shortly thereafter.

G. Construction of the Continuous Catalyst Regeneration (CCR) Reformer and Expansion of the Naphtha HDS Unit. Permit No. 195-M-2. (14)

The application for Permit No. 195-M-2 was dated March 26, 1990 and was received by the Department on March 30, 1990. This application served as the basis for issuance of the permit.

Permit No. 195-M-2 was issued August 28, 1990, and allowed the following changes to the refinery:

1. replacing the existing 2000 BBL/day naphtha charge Reformer with a newly constructed 12,000 BBL/day naphtha charge CCR Reformer [redesignated as a 15,000 BBL/day unit by the Department's letter of December 8, 1994); (14.1.a.1)
   [CCR capacity increased by subsequent modifications – see associated permits for basis and Condition 2 for applicable operating restrictions]

2. expanding the existing Naphtha HDS Unit in order to provide sufficient desulfurized naphtha for processing in the new CCR Reformer; (14.1.a.2)

3. installing newly constructed reactor Heaters 70-H1, 70-H2, and 70-H3 to provide heat for driving the reforming process, all three heaters venting to common stack 70-H1/2/3; (14.1.a.3) [Heater numbers 70-H1, 70-H2 and 70-H3 were changed to H-352, H-353 and H-354 in Permit No. 195-M-25.]

4. installing the newly constructed Reboiler Heater 70-H4 for the reformate stabilizer; (14.1.a.4) [Heater number 70-H4 changed to H-355 in Permit No. 195-M-25.]

5. installing newly expanded Heater H-40 to serve as the naphtha HDS charge heater in place of Heater H-18; (14.1.a.5)

6. shutting down and removing from service existing Heater H-23 and its existing HDS splitter tower; (14.1.a.9)

7. **[CURRENTLY APPLICABLE AS PRESCRIBED BY Permit No. 195-M-6]**: In order to provide the additional heat required by the Naphtha HDS, Heater H-18 may be upgraded from its present firing rate of 12.2 MMBTU/hr to 20 MMBTU/hr by the addition of upper radiant and convection sections. H-18 shall serve as the debutanizer reboiler heater. (1.a.ii) [Heater H-18 firing rate increased to 32 MMBTU/hr in Permit No. 195-M-25.]

8. **[CURRENTLY APPLICABLE AS PRESCRIBED BY Permit No. 195-M-6]**: Relocating Heater H-9 from the south crude unit to the naphtha HDS unit to serve as the splitter reboiler for Splitter Tower W-4; (1.a.i)

9. shutting down and removing from service Heaters H-5, H-6, and H-7 which served the 2000 BBL/day reformer; (14.1.a.8)

10. shutting down and removing Compressors C-10 and C-11 which serviced the existing reformer, and installing an electrically driven compressor for the CCR Reformer; (14.1.a.10)

11. installing VOC-service equipment inside and outside the CCR Reformer battery limits; (14.1.a.11)

12. installing new process wastewater drains and storm water drains joining the existing wastewater system at an existing junction box; (14.1.a.12)

H. Installing a 6700 Barrel per Day Alkylation Unit and Supporting Equipment. Permit No. 195-M-3. (13)

The application for Permit No. 195-M-3 was dated October 1990 and was received by the Bureau on October 10, 1990. This application served as the basis for issuance of the permit.

Permit No. 195-M-3, issued March 14, 1991, allowed the following changes to the refinery:

1. installing an existing, 1962 vintage, 6,700 BBL/day Alkylation Unit and associated 88 MMBTU/hr gas-fired Heater 3F-1 [later redesignated H-600], serving as a depropanizer reboiler heater. (13.1.a.1) [Firing rate for H-600 changed to 84 MMBTU/hr in Permit No. 195-M-25.]

2. **[CURRENTLY APPLICABLE AS PRESCRIBED BY Permit No. 195-M-5-Rev]**.: in accordance with Navajo Refining's request, the Butamer Unit is not to be built or installed (11.1.b.6)

3. installing newly constructed Flare FL-403 to serve the relocated Alkylation Unit and the CCR Reformer during emergency upset Conditions; (13.1.a.3)

4. installing new process wastewater drains within the battery limits of the Alkylation and Butamer [not to be built] units, a new API oil/water separator dedicated to the Alkylation Unit, and a new sewer line to the wastewater treatment plant equalization tank downstream of the existing API oil/water separator; (13.1.a.4)

5. installing newly constructed Cooling Tower Y-7 [redesignated Y-8], which will serve the Relocated Alkylation unit and the CCR Reformer; (13.1.a.5)

6. installing two 12,000 BBL/day pressurized storage tanks to provide additional storage capacity for the increased volume of isobutane feedstock. (13.1.a.6)

I. APPLICABLE WITH CHANGES UNDER PERMIT No. 195-M-7: 20-Long-Ton-Per-Day Sulfur Recovery Unit (SRU) and Supporting Equipment. Permit No. 195-M-4. (12)

The application for Permit No. 195-M-4 was dated December 26, 1990 and was received by the Department on December 27, 1990. This application served as the basis for issuance of the permit. (12.1.a)

Permit No. 195-M-4, issued June 19, 1991 and corrected January 16, 1992 allowed the following changes to the refinery:

1. installing a three-bed Claus Sulfur Recovery Unit (SRU) with a nameplate capacity of twenty long tons per day, sulfur storage tank, and sulfur loading rack; (12.1.b.1)

2. installing Hot Oil Heater H-460 with a maximum rated heat input of 3.5 MMBTU/hr [increased to 5 MMBTU/hr in Permit No. 195-M-25.] to reheat the oil stream circulating through the SRU. (12.1.b.4)

3. **[CURRENTLY APPLICABLE AS PRESCRIBED BY Permit No. 195-M-6]**: Adding upper radiant and convection sections to existing Heater H-18 to increase the heater's maximum heat input capacity from 12.2 MMBTU/hr to 20 MMBTU/hr in order to provide the additional heat required by the Naphtha HDS Debutanizer Tower. (1.a.ii) [maximum heat input capacity increased to 32 MMBTU/hr in Permit No. 195-M-25.]

J. Relocation of Diesel HDS Unit and Associated SRU Upgrade Project. Permit No. 195-M-5-Rev. (11)

The application for Permit No. 195-M-5 was dated June 24, 1992 and was received by the Bureau on June 25, 1992. This application served as the basis for issuance of the permit. (11.1.a)

Permit No. 195-M-5-Rev., issued December 16, 1993 and corrected February 3, 1994, allowed the following changes to the refinery:

1. installing the Diesel HDS and its associated 20 MMBTU/hr charge Heater H-21 (formerly H-421), both relocated from Lovington; (11.1.b.1) [Charge heater re-named H-421 and firing rate increased to 27 MMBTU/hr in Permit No. 195-M-25.]

2. **[BEING RE-AUTHORIZED UNDER 195-M-7]** installing a new 80,000 barrel external floating roof storage tank (T-450) for storing diesel, kerosene, raw naphtha, and sweet naphtha. (11.1.b.2)

3. installing an amine regeneration unit and its associated amine contactor, both relocated from Lovington, to reduce the sulfur content of refinery fuel gas and sulfur dioxide emissions. (11.1.b.3)

4. installing equipment components in VOC service in the relocated Diesel HDS unit, the relocated Amine Regeneration Unit, the relocated Amine Contactor, and other VOC-service equipment components associated with various piping to be installed as part of the project. (11.1.b.5)

5. Removing from Permit No. 195-M-3 the construction of the new 8000 BBL/day butamer unit. (11.1.b.6)

K. Powerformer/Penex Project. Permit No. 195-M-6. (1)

The application for Permit No. 195-M-6 was dated October 1995 and was received by the Bureau on October 25, 1995. This application and the additional correspondence received December 20, 1995, January 5, 1996, February 21, 1996, February 22, 1996, and February 27, 1996, served as the basis for issuance of the permit. (1.a)

This permit, originally issued March 13, 1996 allowed the construction and operation of the Powerformer/Penex unit to alternately produce isomerate in addition to reformate. (1.a)

1. Construction of the Powerformer/Penex unit is limited to the following:

    a. Relocating Heater H-9 from the south crude unit to the naphtha HDS unit to serve as the splitter reboiler for Splitter Tower W-4; (1.a.i)

    b. Adding upper radiant and convection sections to existing Heater H-18 to increase the heater's maximum heat input capacity from 12.2 MMBTU/hr to 20 MMBTU/hr in order to provide the additional heat required by the Naphtha HDS Debutanizer Tower; (1.a.ii) [increased to 32 MMBTU/hr in Permit No. 195-M-25.]

    c. Installing new Debutanizer Tower W-181 in the naphtha HDS unit; (1.a.iii)

    d. Installing equipment components in VOC service in the existing Powerformer Unit, the Naphtha HDS Unit, and various VOC-service equipment components associated with piping to be installed as part of the project; (1.a.iv)

    e. Double handling (increased throughput) of light naphtha (LSR) in light oil storage tankage; (1.a.v)

2. Constructing, installing, and operating a 5000 BBL external floating roof tank, T-435, to replace the two open pits currently used to store oily wastewater drawn from crude tanks T-437 and T-439. Tank T-435 shall be constructed, installed, and operated in accordance with all representations in the supplemental letter dated November 13, 1995 unless modified by conditions of this permit. (1.c)

L. Wastewater Treatment Plant Upgrade, Changes in Supplemental Heat for Flare Fl-403, Changes in Throughput and Vapor Pressure for Material Stored in Tank T-450, Construction of a tail gas cleanup unit and auxiliary blower for the SRU. Permit No. 195-M-7.

The different sections of the application for Permit No. 195-M-7 were put together and sent in on different dates during the second half of 1996 and the beginning of 1997. These items were initially planned to be issued along with the other changes to the permit currently being handled under permit application No. 195-M-8. The items currently being handled under permit application No. 195-M-7 were separated from items being handled under permit application No. 195-M-8 in April 1997, to expedite the upgrade of the Waste Water Treatment Plant (WWTP) required by the Department of Justice. Other items being processed under this permit are being authorized with the WWTP upgrade project in this permit. The updated application for the WWTP upgrade project was dated July 19, 1996, the revised application for variation of supplemental heat was dated October 21, 1996 and received October 24, 1996 and the application for the construction of the 80,000 barrel external floating roof (EFR) swing tank was dated December 12, 1996 and received December 13, 1996. The installation of the SRU tail gas cleanup unit was requested by Navajo in a letter to the Department dated July 22, 1997.

The items being processed under this permit (195-M-7) include the following changes to the refinery:

a) WWTP upgrade consisting of the following:
   1) Implementation by the permittee of upstream waste minimization and other wastewater treatment (including aerobic microorganism direct metabolism or co-metabolism of benzene and other VOC) accomplishes sufficient reduction of these compounds to meet all regulatory requirements for wastewater quality. The removal of the Kerosene extraction system (KES) and Solvent Separator (SOLSEP) units, which will increase the VOC emissions for the 30, 000-barrel surge equalization tank T-836 by 0.27 lb/hr (0.68 ton/yr), is authorized under this permit modification. (195-M-13)
   2) Modifying the service of Tank-435 by re-routing certain wastewater streams through this tank to allow for processing of supplemental wastewater streams.

b) Changing the permit condition in permit No. 195-M-6 that requires 52.9 MMBTU/hr of supplemental heat to be added during acid gas flaring of flare FL-403 to require supplemental heat to be provided in proportion to the quantity of acid gas being flared;

c) Changing the throughput and vapor pressure for material stored in the 80,000 bbl EFR swing tank T-450, originally authorized for construction under 195-M-5-Rev and re-authorized for construction by a Department letter dated May 6, 1997.

d) Constructing a tail gas cleanup unit and auxiliary blower to reduce SO2 emissions from the SRU as required by NSPS Subpart J. Except during upset periods when Kerley Chemical cannot accept sulfur feed from Navajo (i.e., Navajo may increase the SRU feed rate to minimize acid gas flaring), the SRU is limited to 30.5 LTPD of sulfur feed to the SRU with a substantial decrease in SO2 emissions.

M. Replacement of Boiler B-3 (58.0 MMBTU/hr) with Boiler B-6 (43 MMBTU/hr). Permit No. 195-M-9.

The application was received on February 2, 1998. Boiler B-4 will continue to operate but with an independent stack. Boiler B-6 will also have an independent stack. [Boiler B-6 was replaced by Boilers B-7 and B-8 pursuant to Permit No. 195-M14.]

N. Replacement of Tanks T-42 and T-70 with Tank T-3000. Permit No. 195-M-9-R-1.

The application was received on August 21, 1998. Two pressurized bullet-shaped tanks (T-42 & T-70), previously used to store liquefied petroleum gas (LPG), were replaced with a single pressurized spherical tank to store isobutane and LPG. The fugitive volatile organic compound emissions from the associated equipment components of the tank shall not exceed 1.45 pounds per hour and shall not exceed 6.54 tons per year.

O. Leak Detection, Monitoring and Repair (LDMAR), North Plant Amine Treating/Regeneration Area. 195-M-9-R-2.

The application was received on December 15, 1998. The LDMAR program is already in place for other equipment at the facility. Inclusion of the North Plant Amine Treating/Regeneration Area is a voluntary environmental improvement activity undertaken as part of the settlement for an enforcement action. The specific requirements are contained in Condition 4.K.

P. Polymer Modified Asphalt (PMA) for blending purchased polymer into refinery asphalt. Permit No. 195-M-9-R-3. [This Project is suspended indefinitely {OBSOLETE}.

The application was received on September 13, 1999. The unit includes: a softener tank, two polymer concentrate tanks, a new 15.0 MMBTU/hr hot oil heater (H-444), existing asphalt tanks (TKS 409/410), wetting vessel, polymer pellets hopper(s), an inline polymer mill, inline static mixer and existing asphalt tanks (TKS 420/422/423).

Heater H-444 is added to the list in Condition 5.B (NSPS Subpart J). Condition 5.H (NSPS Subpart Dc) is created in this permit and Heater H-444 is the affected heater. Heater H-444 is added to Table 1 with a limit of 0.9 pounds per hour of NO_2. [not built and likely will not be built]

Condition 5.I (NSPS Subpart UU) is created by this permit and the two polymer concentrate tanks are the affected units. These same two tanks are added to the list of affected tanks in Condition 5.E (NSPS Subpart Kb).

Note: Tanks 409/410/420/422/423 and the two concentrator tanks are exempt sources as defined by 20.2.72 202B.2. NMAC.

Q. Increase SRU/TGU capacity to 40 long tons per day. Permit No. 195-M-10.

The application was received March 5, 1999. This significant permit revision increased the capacity of the sulfur recovery unit with the tail gas incinerator (SRU/TGU) to 40 long tons per day.

R. Increase Heater H-40 capacity. Permit No. 195-M-10-R-1.

The application was received January 24, 2000. Application for permit did not qualify for technical permit revision under 2.72.219.B.1.b. No permit was issued. **[OBSOLETE.]**

S. New 100 LT/D SRU2/TGU2. Permit No. 195-M-12.

The application was received September 23, 1999. Includes Unit H-473 and Unit H-470. Used in conjunction with SRU1/TGU1 for a refinery sulfur recovery system (SRU1 and SRU2) with a combined sulfur recovery capacity of 140 LTPD to handle increase in feed stock sulfur content and the pending shutdown of Kerley Chemical. SO2 CEMS required to track combined emissions from both SRUs. VOC equipment associated with SRU2/TGU2 are subject to CFR Title 40, Part 60, Subpart GGG. (see Dept. letter dated Jan 31, 2000, Permit File 195M12)

TGU2 was not constructed; H-463 has been shut down. TGU1, with H-473, at a total capacity of 70 LTD, serves as a combined TGU for both SRU1 and SRU2. (195-M15)

T. New No. 3 Blender, Remove KES/SOLSEP from WWTP. Permit No. 195-M-13.

The application was received May 12, 2000. Modification that includes a new product blender (No. 3 Blender) with pumps, valves, piping and instrumentation with potential fugitive emissions of volatile organic compounds (VOC). This blender is supplementing the existing two blenders, along with blendstock and product tankage referred to in Table 2.D of Permit 195-M-9 as "Gasoline Blending Unit (Light Oil Tankage)." Subject to CFR Title 40, Part 63, Subpart CC for leak detection and repair (LDAR) for VOC fugitives from the blending equipment.

U. Replaced Boilers B-1, B-2, B-4, B-6, B-103, B-104, B-105 with Boilers B-7, B-8. Replaced Heater H-26 with Heater H-30. Permit No. 195-M-14.

Application received October 10, 2000. New, efficient B-7 and B-8 steam boilers to replace seven, older, less efficient steam boilers. Also replace H-26 with H-30.

V. Changes in plans, specifications, and other representations stated in the application documents shall not be made if they cause a change in the method of control of emissions or in the character of emissions, or will increase the discharge of emissions. Any such proposed changes shall be submitted as a revision or modification as provided in Condition 10 (Revisions and Modifications) of this permit. (1.i, 2.e)

W. Gas Oil Hydrotreater Project. Permit No. 195-M15.

The application was received May 23, 2001. This significant permit revision allows the following changes to the refinery:

1. Installing a new Gas Oil Hydrotreater Unit (incl. H-601);
2. Installing a new Flare (FL-404);
3. Installing a new stripper at the Amine Unit and upgrading the TGU1 (e.g., to accept MDEA additives), provided that the total capacity of the SRU1/SRU2/TGU1 operation does not exceed 70 tons per day of sulfur;
4. Modifications to FCCU to increase throughput (new air lift blower; 2 new ESPs, 2 pumps, heat exchangers, tower internal upgrades);
5. Modifications to CCR to increase throughput (new H_2 compressor, new pump);
6. Modifications to Diesel HDS to increase throughput (new pump, increase in H-21 firing [actual]); [Unit H-21 renamed to H-421 in Permit No. 195-M-25.]
7. Increased throughput in gas oil tanks (e.g., T-400, T-438);
8. Increase throughput of product storage/loading and sulfur production;
9. Modifications to South Crude Unit to increase throughput (new low-NOx burners in H-20, increase in H-20 firing [actual]);
10. ~~Modifications to Flasher Tower and Vacuum Unit to increase throughput (new low-NOx burners in H-11 [with a decrease in maximum firing capacity], tower internal upgrades, increased heater firing [actual] in H-11 and H-28).~~ [OBSOLETE – Modifications to Flasher Tower and Vacuum Unit were not made. Heaters H-11 and H-28 were not modified and revert to their original fired duties and emission rates.]
11. Modifications to Naphtha HDS Unit (new H_2 compressor, increased firing [actual] in H-9 and H-18);
12. Modifications to JP8 HDS Unit (new pump and distillation column "kerosene stripper" which will use existing steam).

X. Administrative Revision No. 0195-M15 R1 to incorporate two exempt gas oil storage tanks.

Administrative revision filing received May 29, 2002 for two new gas oil storage tanks (T-409 and T-433) which met the exemption from permitting vapor pressure criteria of 20.2.72 202.B.2 NMAC.

Y. New Hot Oil Heater (H-464). Technical Permit Revision No. 0195-M15 R2.

The application was received September 4, 2003. The revision issued October 22, 2003 was for a new Hot Oil Heater to be equipped with three (3) CTI Low-NOx Burners having a minimum 50% NOx reduction efficiency.

Z. Install a Solvent De-Asphalting unit; and Update various permit conditions to reflect wet gas scrubber control on the FCCU (vs. ESPs), to Add NOx ppm limits for boilers B-7 and B-8, to Incorporate certain consent decree requirements as enforceable permit conditions and retrofit B-105 with Ultra-Low NOx Burners. Significant Revision No.

0195-M-17.

The application was received November 21, 2003. The application reflected the resubmittal of the July 11, 2003 request for incorporation of the Consent Decree (CD) emission limits, emission standards, and schedules for emission controls effective upon the December 21, 2001 date of lodging. Supplemental application information was received December 23, 2003, January 28, 2004, August 4, 2004 and August 31, 2004.

AA. Install Butane and Alkylate Treaters and Associated Fugitive Equipment (the application reflected 40 light liquid valves, 2 flare relief valves and 60 flanges) in the existing Alky Unit.

The application for technical revision was received April 17, 2004. Technical Permit Revision 195-M-15-R3 was issued May 19, 2004.

BB. Permit modification to incorporate federally enforceable conditions as required by Paragraph 24 of the Consent Decree in United States et al. v. Navajo Refining Co. and Montana Refining Co., lodged December 20, 2001, in the United States District Court for the District of New Mexico ("Consent Decree"). Significant Revision No. 0195-M-18.

CC. Install alkylate splitter and other associated equipment FUG-NALKY, FUG-TRTR, FUG-SALKY & FUG-BLND [changed to FUG-09-N ALKY, FUG-18-LSR MEROX TRT, FUG-43-S ALKY and FUG-29-BLENDER/TK FARM in Permit No. 195-M-25]. All pump seals shall meet the requirements specified by 60.482-2 (d)1-6. All CBG fugitive components shall be subject to permit condition 7. Significant Revision No. 0195-M-18.

The application for significant revision was received October 22, 2004. Permit Revision 195-M-18 was issued February 22, 2005.

~~**DD. Install two new 90,000 bbl naphtha tanks.** This revision authorizes the construction of two new external floating roof tanks for the storage of naphtha or other light (high vapor pressure) oils and other associated equipment including pumps, valves, and piping.~~

~~The application was received January 31, 2005. Significant Revision No. 0195-M19 was issued August 22, 2005.~~ [OBSOLETE - These tanks were never installed. Tanks T-0078 and T-0079 will be installed instead, see condition 1.LL.]

EE. Install four new heaters, process vessels, and other associated equipment including heat exchangers, pumps, valves and piping to configure the refinery for the production of Ultra Low Sulfur Diesel (ULSD) fuel. The production of ULSD fuel is a federal clean fuels requirement.

The application was received March 7, 2005. Supplemental/amended application information was received June 16, 2005 and December 2, 2005 and a modeling analysis including ULSD sources was received July 13, 2005. Significant Revision No. 0195-M-20 was issued 01/23/2006. (significant revision 195-M-20).

This significant permit revision allows the following changes to the refinery:

- Conversion of the existing Gas Oil Hydrotreater (GOHT) Unit to produce ULSD meeting federal low sulfur requirements. Fugitive components will be added to the existing fugitive area (i.e., fugitive area FUG-GOHT) [changed to FUG-33-DIST HDU in Permit No. 195-M-25.]

- Installation of a parallel second train at Navajo's existing DHDU and the change in service of the existing DHDU to gas oil service (i.e., functioning as GOHT2). A new heater (H-2421) will be added for the second train as well as fugitive components which will be incorporated into the existing area (i.e., fugitive area FUG-DHDS) [changed to FUG-44-DIST HDU and FUG-45-DIST HDU in Permit No. 195-M-25];

- Conversion of the existing JP8 unit to function in batch mode to hydrotreat either JP8 or naphtha. Fugitive equipment components (i.e., fugitive area FUG-JP8) [changed to FUG-06-NHDU in Permit No. 195-M-25] will now have the potential to be in HAP service;

- Installation of three new helper heaters (one per reactor H-362, H-363 & H-364) to allow the existing CCR to generate additional hydrogen for Navajo's hydrotreating units. Some equipment components will also be added (i.e., fugitive area FUG-CCR) [changed to FUG-70-CCR in Permit No. 195-M-25];

- An option to modify SRU2 by installing an oxygen enrichment process which affects emissions from the existing tail gas incinerator, H-473 (Stack No. 054) and increasing SRU2's capacity to a nominal 130 LTPD; and

- Installation of other process vessels, piping, equipment components, and instrumentation at various locations within the refinery pertaining to the implementation of the above changes as represented by the permit application.

FF. Install a new gas-fired crude oil heater (H-19) to supplement the existing gas-fired crude oil heater (H-20) and install other equipment associated with the South Crude Unit Efficiency Project.

The new crude oil heater (H-19) will be equipped with next generation ultra low-NOx burners (NGULNBs). This significant revision also revises the permit allowable emission rate for existing crude oil heater (H-20) reflecting its retrofit with NGULNBs.

The application was received on April 12, 2005. Significant Revision No. 0195-M-21 was issued November 18, 2005.

GG. Install a new nominally rated 10 MMSCF/D hydrogen plant comprised of a nominally rated 120 MMBTU/hr gas (natural and/or refinery) fired reformer heater (H-H2), process vessels and other associated equipment including heat exchangers, pumps, valves, and piping needed to produce hydrogen (FUG-H2 & V-H2) [changed to FUG-63-H2 PLANT-1 in Permit No. 195-M-25]. The proposed new heater will be equipped with Next Generation Ultra Low NOx Burners ("NGULNBs"). Significant Revision No. 0195-M-22.

The primary function of the new hydrogen plant is to allow the refinery to process more sour crudes, position the refinery to produce Ultra Low Sulfur Gas by 2010 and provide back-up hydrogen supply when the CCR unit fails or operation is temporarily curtailed. The proposed hydrogen plant is not required to meet the design hydrogen demands of the ULSD project. The entire design ULSD hydrogen demand of 30 MMMSCF/D can be met by the proposed CCR expansion associated with the ULSD project permit. (Significant Permit Revision No. 0195-M-22).

The application was received June 16, 2005. Significant Revision 195-M-22 was issued October 13, 2005.

HH. Construct a naphtha splitter consisting of approximately 700 fugitive components to the existing naphtha unit (FUG-06-NHDU). The project along with the existing Naphtha unit are subject to 40 CFR 60 Subpart(s) A, GGG & QQQ, 40 CFR 61 Subpart(s) FF and 40 CFR 63 Subpart(s) A & CC. (Technical Permit Revision No. 195-M24-R1).

II. Relocate existing tank T-437 to the area north of tank T-450.(Administrative Permit Revision No. 195-M24-R3).

JJ. The permittee is authorized construct the Propane Test and Release Project ("PTRP") by modifying the existing units: FUG-08 – Liquid Propane Gas, FUG-09 – North Alkylation Unit, FUG-18 – LSR Merox Treater, FUG-35 Saturates Gas Plant, and FUG-02 – South Crude Unit, and constructing two pressurized propane storage tanks (T-76 & T-77). The project components are subject to 40 CFR 60 Subpart(s) A and GGG, 20.2.37 NMAC, and 40 CFR 63 Subpart(s) A & CC. (Technical Permit Revision 195-M24-R4).

KK. PSD permit modification to expand the Artesia Refinery: Proposed changes include construction of the following: a Hydrocracking Unit, a Solvent De-Asphalting Unit (SDA or ROSE), a saturates gas plant, a sulfur recovery unit, a hydrogen plant, a wastewater treatment plant, a flare, a cooling tower, and associated piping components, and storage tanks. The proposed sources added to this permit were reviewed pursuant to the Prevention of Significant Deterioration (PSD) rules for the following air contaminants: nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO2), particulate matter (PM), particulate matter less than 10 microns in diameter (PM10), and volatile organic compounds (VOCs) All increases within the contemporaneous period (01/01/2002 – 01/01/2007) for the air contaminants subject to PSD review were included in the net emission rate increase and therefore future projects will address only those increases in emissions occurring after the date this permit is issued. (Significant Permit Revision and PSD permit No. PSD-NM-195-M25).

LL. Install one new 50,000 bbl and one new 80,000 bbl isomerate tanks. This revision authorizes the construction of two new external floating roof tanks for the storage of isomerates or other high vapor pressure liquids and other associated equipment including pumps, valves, piping and other fugitive components.

The application for a technical revision was received on April 14, 2008. Technical Permit Revision No. PSD-NM-0195-M25-R2 was issued on May 14, 2008.

Note: Application file numbers 195-M-8 and 195-M-16 did not result in any permit being issued. Application file number 195-M-11 received June 29, 1999, for the Gas Oil Hydrotreater (GOHT), as submitted was deemed a modification subject to PSD review, and the application ruled incomplete July 28, 1999. Permit not issued. Application file number 195-M23 was withdrawn by the applicant, therefore no revision was issued. Application file number 195-M24-R2 was withdrawn by the applicant, therefore no revision was issued. Application file number 0195-M25-R1 was combined with application file number 0195-M25-R2 and issued as a single technical permit revision, PSD-NM-0195-M25-R2.

2. Control Equipment and Operating Restrictions

A. The naphtha charge rate to the CCR Reformer shall not exceed 12,000 BBL/day. (M-2) [Changed to 15,000 BBL/day by the Department's letter of December 8, 1994.] (14.1.b) [Increased to 18,000 BBL/day 195-M15.] (M-15). [Increased to 24,000 BBL/day] (M-20). Heaters 70-H1, 70-H2, and 70-H3 [redesignated H-352, H-353 and H-354] shall be retrofitted with next generation ultra-low NO_x burners no later than December 31, 2009. (M-17).

Note: "Next Generation Ultra-Low NOx Burners" or "Next Generation ULNBS" shall mean those burners new to the market that are designed to achieve a NOx emission rate of 0.012 to 0.020 lb/MMbtu/HHV when firing natural gas at three percent stack oxygen at full design load without preheat.

B. Heater 3F-1 [redesignated H-600], serving the relocated Alkylation Unit, is limited to a firing rate of 88 MMBTU/hr [changed to 84 MMBTU/hr (M-25)] and shall be equipped with staged-fuel, low-NO_x burners to reduce NOx emissions. (M-3) (13.1.b). H-600 shall be retrofitted with next generation ultra-low NO_x burners no later than December 31, 2009. (M-17 and Consent Decree, Paragraph 16 and Appendix C). The retrofit for this unit is authorized by M25-R2. After the retrofit, the NO_X emissions from H-600 shall not exceed 0.03 lb per MMBtu (LHV) on a 3-hour rolling average basis at 3% excess oxygen.

C. The continuous operation of SRU1/TGU1, SRU2/TGU2, and tail gas incinerators, Units H-463 and H-473, is authorized to allow additional sulfur from the shutdown of the Kerley Chemical Plant and from an increase in the crude sulfur content processed by the refinery. The efficiency of these units shall be maintained sufficient to meet the combined emission limit for Units H-463 and H-473 listed in this permit modification, 195-M-12. Continuous emissions monitors shall be used to demonstrate compliance with the combined SO_2 emission limit for these units. (M-12)

Note: TGU2 was not constructed; H-463 has been shut down. SRU1 and SRU2 are served by one tail gas treating unit (TGU) and tail gas incinerator ("TGI") H-473. The emission limit for H-473 (and therefore including SRU1/SRU2) shall continue to be monitored via CEMS (November 2001 and M-20)

D. The 80,000 barrel hydrocarbon storage swing tank T-450 shall be equipped with an external floating roof and double seals to reduce VOC emissions to the atmosphere. The maximum true vapor pressure of any volatile organic liquid stored in tank T-450 shall not exceed 4.8 psia (changed to 11.0 psia in permit No. 195-M-7). (M-5-Rev) (11.1.b.2)

E. ~~**[CANCELLED]**~~ The production rate of the Unit 44 shall not exceed 15,000 barrels per day. (M-5-Rev) (11.1.d) [Increased to 18,000 barrels per day.] (M-20).

F. ~~Diesel HDS Charge~~ Gas-oil Hydrotreater (GOHT2) Heater H-21 is limited to a firing rate of 20 MMBTU/hr [increased to 27 MMBTU/hr in M-25] and shall be equipped with low-NOx burners to reduce NOx emissions. (M-5-Rev) (11.1.b.1) (M-20)

G. All sulfur released in plant processes up to 30 tons per day shall be recovered with a control efficiency of at least 90 percent. All sulfur released in plant processes in excess of 30 tons per day shall be recovered with a control efficiency of at least 98 percent. (M-5-Rev) (11.2.c)

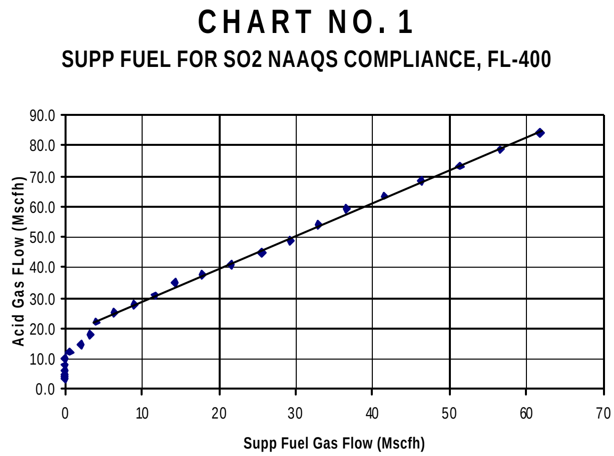
H. Heater H-9 shall be equipped with low-NOx burners to reduce NOx emissions. (M-6) (1.a.1)

I. Wastewater tank T-435 shall be equipped with an EFR (changed from internal floating roof (IFR) in permit No. 195-M-6) to minimize VOC emissions. (M-6) (1.c)

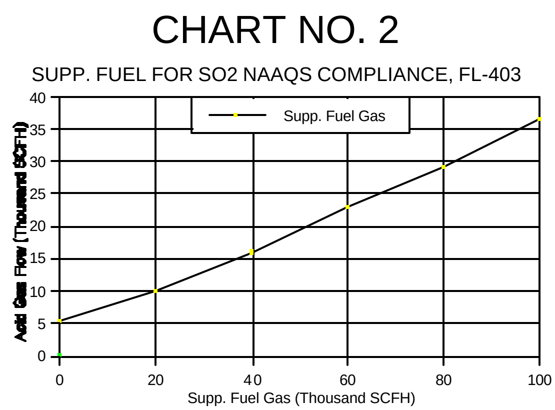
J. In accordance with the requirement that Navajo Refining prevent exceedances of the 24-hour and 3-hour National Ambient Air Quality Standards (NAAQS) for SO2 during major refinery malfunctions, Navajo Refining shall only flare acid gas from existing Flare FL-403 according to Navajo Refining's "Phase Two" plan dated January 5, 1996 and received by the Department on

January 8, 1996, or from Flare FL-400. Navajo shall undertake the following measures for acid gas flaring from FL-400 or FL-403 (M-6) (1.f), (M-17):

1. Existing Flare FL-400 shall be equipped with a flare tip or burners to supply supplemental fuel gas to provide enough heat to supplement the heat released by combustion of the acid gas itself and the heat provided by smoke-suppressing steam. The minimum flow rate of supplemental fuel gas to be supplied during acid gas flaring such that compliance with the NAAQS for SO_2 is assured shall be determined using Chart No. 1. The fuel gas used for this purpose shall be sweetened fuel gas or sweet natural gas.



2. Existing Flare FL-403 shall be equipped with a flare tip or burners to supply supplemental fuel gas to provide enough supplemental heat. The volume of supplemental fuel gas to be provided to generate enough supplemental heat to ensure compliance with NAAQS for SO_2 shall be determined using Chart No. 2. The supplemental heat to be provided when flaring the maximum quantity of acid gas has been determined to be 52.9 million BTU per hour which is generated by burning 96,200 SCFH of supplemental fuel gas. This assumption has been made to ensure compliance with the NAAQS for SO_2. The fuel gas used for this purpose shall be sweetened fuel gas or sweet natural gas. (M-6) (1.f.ii, 1.f.iv revised)



K. The-South Crude Unit is limited to processing a maximum of eighty thousand (80,000) BBL/day of crude oil feed charge averaged over each calendar month. (M-6) (1.h) (M-24).

L. The charge rate to the Powerformer/Penex unit when operated in the Powerformer mode shall be limited to nine thousand (9000) barrels per day. The charge rate to the Powerformer/-Penex unit when operated in the Penex mode shall be limited to fourteen thousand (14,000) barrels per day. (M-6) (1.a)

M. The Powerformer/Penex unit may operate in either the Powerformer mode or in the Penex mode but shall not operate simultaneously in both modes. (M-6) (1.a)

N. The Heavy Naphtha Merox Unit equipment removed from VOC service shall not be operated in VOC service while the Naphtha HDS unit equipment is in VOC service. (M-6) (1.a.vi)

O. The steam required to operate the Powerformer/-Penex unit shall be provided by boilers B-7 and B-8, which are replacing B-1, B-2, B-4, B-103, B-104, and B-105. (M-6) (1.a.vii)

P. In order to control VOC emissions, all idle equipment in the Powerformer/Penex unit that is not blinded or otherwise isolated from the process shall be pressurized with sweet purchased natural gas or nitrogen until the equipment is used. (M-6) (1.a.viii) (M-22)

Q. The truck loading rack shall be equipped with a carbon adsorption system for compliance with the MACT requirements.

R. Fuel Sulfur Restrictions. In accordance with Table 4.1-2 of permit application no. 195-M-4, the indicated units in Table I shall be fired on purchased natural gas, sweetened refinery fuel gas, sweetened hydrogen from the CCR Reformer, or any combination of these fuels. The H_2S concentration of the fuel feed is not to exceed 0.1 grain/dscf. (1.a.i, 1.a.ii, 11.1.b.1, 11.2.c, 12.1.c, 12.3.a, 13.1.b, 14.3.a)

S. Operating Hours. The refinery is authorized to operate 24 hours per day, 7 days per week, and 52 weeks per year for a total of 8760 hours per year:

T. The 80,000 barrel swing tank (T-450) for which construction was authorized on May 6, 1997 shall be equipped with an EFR and shall only be used for storing hydrocarbon liquids with a vapor pressure of 11 psia or less. (M-7)

U. Duties of tank T-435 which currently is used to store oily waste water will be expanded to include receipt of surge flows from the water draw from tank T-57 and non-process sump draws. (M-7)

V. The Air Stripper and Tank T-836 are vented to the atmosphere. (M-7)

W. The GOHT Process Heater H-601 and South Crude Unit Heater H-20 shall be equipped with next generation ultra-low NO_X burners no later than December 31, 2005. (M-17)

X. Existing Vacuum Flasher Heater H-11 is limited to a firing rate of 38 MMBTU/hr (M-25) [Consistent with Alternate Scenario 2 of operating permit P051 and the technical review for M-17, low-NOx burners are not required since the expansion affecting H-11 did not occur.

Significant Revision 195-M-17 restored the Table 1 allowable emission rates for H-11 to their previous levels]. (M-22).

Y. The new Flare FL-404 may service the entire Refinery or any portion thereof and will comply with all of the flare requirements in 40 CFR 60.18 (NSPS) and in 40 CFR 63.11 (MACT). Notwithstanding, acid gas flaring shall be limited per Condition J. (M-15)

Z. The FCCU Catalyst Regenerator shall be equipped with a flue gas scrubber as described in Condition CC. (M-17)

AA. In accordance with 20.2.61 NMAC, visible emissions from the Heater, Unit No. H-464, shall not equal or exceed 20% opacity as determined by EPA Reference Method 9. For the Heater, the use of NSPS quality refinery fuel gas with a maximum hydrogen sulfide (H_2S) content of 0.10 grains/dscf or less, on an ongoing basis, shall be sufficient to demonstrate compliance with the opacity restrictions. Heater H-464, authorized by technical permit revision (NSR Permit No. 0195 M-15 R2), shall comply with 40 CFR Part 60, Subparts A and J by firing NSPS quality refinery fuel gas with a maximum hydrogen sulfide (H_2S) content of 0.10 grains/dscf or less, as specified in 40 CFR §60.104(a)(1) (M-15 R2).

BB. Visible Emissions Restrictions for Flares

In accordance with 20.2.61 NMAC, visible emissions from the Flares (Units FL-401, FL 402, FL-403, FL-404), shall not equal or exceed 20% opacity as determined by EPA Reference Method 9. Additionally, the Flares are subject to 40 CFR §60.18 (and/or 63.11) and shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. As specified in 40 CFR § 60.18 (and /or 63.11), and its referenced subparts, EPA Reference Method 22 shall be the approved procedure for demonstrating compliance with the visible emissions requirement. Reference Method 22 shall be conducted annually, on each flare to demonstrate continued compliance with the no visible emission requirement.

Compliance with 20.2.61 NMAC shall be determined on a quarterly basis in accordance with 20.2.61.114 NMAC. (M-17)

CC. Consent Decree Provisions to install a Wet Gas Scrubber on the FCCU

As specified in Paragraphs 12.B and 13.B of the Consent Decree, by no later than December 31, 2003, the permittee shall complete installation of and shall begin operation of a Wet Gas Scrubber ("WGS") to reduce particulate and SO_2 emissions, and opacity from the Fluid Catalytic Cracking Unit (FCCU). The WGS shall be designed to achieve, and by no later than December 31, 2003 shall fully comply with, all emissions (and opacity) limits in permit condition 3.G. The limits are contained in NSPS Subpart J and have been incorporated into the permit pursuant to the Consent Decree. (M-17; CD ¶12.A & ¶12.B)

DD. Consent Decree Provisions to implement a program to reduce NO_x from the FCCU

1. *Summary:* Navajo shall implement a program to reduce NO_x emissions from Fluid Catalytic Cracking Units ("FCCUs") at the Artesia Refinery ("Artesia FCCU") by the use of NO_x Reducing Catalyst Additives and Low NO_x Combustion Promotors. Navajo shall incorporate lower NO_x emission limits into permits and will demonstrate ongoing compliance with the lower emission limits through the use of CEMS. (M-17; CD ¶11.A)

2. *Establishing FCCU NO_x Emission Limits:* In each NO_x Additive Demonstration Report, Navajo shall propose for the FCCU, a concentration-based (ppmvd) NO_x emission limit based on 3-hour rolling and 365-day rolling averages, corrected to 0% oxygen. Navajo shall comply with the proposed emission beginning immediately upon submission of the NO_x Additive Demonstration Report. Navajo shall continue to comply with these limits unless and until they are required to comply with the emissions limits set by EPA pursuant to Consent Decree Paragraph 11.E.ii. Under no circumstances shall this emission limit for the Artesia FCCU be greater than a concentration-based limit that would be equivalent to 34.9 lb/hr. (M-17; CD ¶11.A & ¶11.E.i)

3. *Compliance with FCCU NOx Emission Limits:* By no later than December 31, 2003, the permittee shall demonstrate compliance with FCCU NOx Emission Limits by installing CEMS in accordance with 40 CFR 60.13 and Part 60 Appendix A and the applicable performance specification test of 40 CFR Part 60 Appendices B and F. (M-17; CD ¶11.F)

EE. The FCCU Regenerator shall be an affected facility, as the term is defined in the Standards for Performance for New Stationary Sources ("NSPS"), 40 CFR Part 60, and shall be subject to and comply with the requirements of NSPS Subparts A and J for SO_2, PM, CO, and opacity by no later than December 31, 2003. (M-17; CD ¶15)

FF. Heaters and Boilers at the Refinery are affected facilities, as the term is used in 40 CFR Part 60, Subparts A and J and shall be subject to and comply with the requirements of NSPS Subparts A and J for fuel gas combustion devices by no later than December 20, 2001. (M-17; CD ¶17.B)

GG. Beginning December 20, 2001 no fuel oil may be burned in combustion units except as follows: (M-17; CD ¶17.C)

1. Torch Oil may be burned in the FCCU Regenerator during FCCU start-ups; and.

2. Fuel Oil may be burned in combustion units after the establishment of FCCU NO_x emissions limits pursuant to permit condition 3.H, provided that emissions from any such combustion units are routed through the FCCU Wet Gas Scrubber and Navajo demonstrates, with the approval of EPA, that the NO_x emissions limits contained therein and the SO_2 emissions limits stated in 3.G will continue to be met.

HH. Navajo shall route all Sulfur Recovery Plant (SRP) sulfur pit emissions from the SRP so that sulfur pit emissions to the atmosphere either are eliminated or are included and monitored as part of the applicable Sulfur Recovery Plant's tail gas emissions that meet the NSPS Subpart J limit for SO_2 in permit condition 5.D.4. (M-17; CD ¶18.C.ii)

II. The SRP and TGU (and any supplemental control devices) shall be operated and maintained, to the extent practicable, in accordance with the obligation to minimize SRP emissions through implementation of good air pollution control practices required by 40 CFR § 60.11(d), at all times, including periods of start-up, shutdown, and malfunction. (M-17; CD ¶18.C.iii)

JJ. All Flares at the Refinery are affected facilities, as the term is used in 40 CFR Part 60, Subparts A and J and shall be subject to and comply with the requirements of NSPS Subparts A and J for fuel gas combustion devices by no later than December 20, 2001. (M-17; CD ¶19.A)

KK. Investigations and evaluations shall be undertaken for each Acid Gas (AG) Flaring and Tail Gas (TG) Incident (as those terms are defined in the Consent Decree) to assess whether future incidents are due to malfunctions or subject to stipulated penalties. The procedures, as set forth in paragraph 20 of the Consent Decree, require a root cause analysis and corrective action for all types of AG Flaring and TG Incidents and stipulates penalties for AG Flaring and TG Incidents if the root causes were not due to Malfunctions. The terms “Malfunctions” and “Root Cause” for the purposes of this permit and the Consent Decree and the reports and documents submitted pursuant thereto shall be as defined in the Section IV Definitions, Paragraph 10, subparagraphs AA and PP, respectively, of the Consent Decree. In response to any AG Flaring Incident, the permittee shall take, as expeditiously as practicable, such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of the AG Flaring Incident. For TG Incidents, the same investigative, reporting, corrective action and assessment of stipulated penalty procedures shall be followed as for AG Flaring Incidents. These procedures shall be applied to TGU shutdowns, bypass of the TGU, unscheduled shutdowns of the SRP, or other miscellaneous unscheduled SRP events, which result in a TG Incident. (M-17; CD ¶20.A, ¶20.B, & ¶20.E)

LL. Operation of 40 LTD Sulfur Recovery unit (SRU) on Hot Standby

All equipment, piping, instrumentation, and controls necessary to allow the permittee to operate the refinery’s 40 LTD sulfur recovery unit continuously on "hot" stand-by shall be installed by no later than December 31, 2003. (M-17; CD ¶30)

MM. Installation of an Additional Wet Gas Compressor at the FCCU

An additional wet gas compressor shall be installed and it shall be operated so as to minimize the duration of any AG or HC Flaring Incidents associated with outages of the original wet gas compressor by no later than December 31, 2003. (M-17; CD ¶31)

NN. Control of Hydrocarbon Flaring Incidents

For Hydrocarbon (HC) Flaring Incidents, the same investigative, reporting, and corrective action procedures shall be followed as for AG Flaring Incidents; provided however, that stipulated penalties as provided for by Consent Decree Paragraphs 20 and 51 shall not apply and, in lieu of analyzing possible corrective actions and taking interim and/or long-term corrective action for a HC Flaring Incident attributable to the start up or shut down of a unit that has been previously analyzed under Paragraph 21 of the Consent Decree, as applicable, may identify such prior analysis when submitting the incident report required under Paragraph 21 of the Consent Decree. (M-17; CD ¶21)

OO. NO_x Emissions Reductions from Heaters and Boilers

Next Generation Ultra-Low NO_x Burners ("NGULNBs") or Alternative NO_x Control Technology shall be ~~installed~~ retrofitted on the refinery Heaters and Boilers as identified in Conditions OO.1 and OO.2 below. New heaters shall be installed with the NO_x Control Technology specified in Conditions OO.3 and OO.4 below. Monitoring pursuant to permit Condition 4.Q shall be performed to demonstrate continuous compliance with the NO_x limits through the use of source testing, CEMS, and/or parametric monitoring. The terms NGULNBs and Alternative NO_x Control Technology shall have the same meaning as those terms are defined by permit condition 2.A. (M-17; CD ¶16) (M-20) (M-21) (M-22)

1. Retrofit with NGULNBs: Heater H-20 by no later than December 31, 2003; Heater H-601 by no later than December 31, 2005; and Heaters H-600, 70-H1, 70-H2 and 70-H3 [redesignated H-352, H-353, H-354] by no later than December 31, 2009
2. Retrofit with Alternative NO_x Control Technology: Boiler B-7 by no later than December 31, 2002, and Boiler B-8 by no later than December 31, 2003.
3. Construct Heaters ~~H-602,~~ H-H2 and H-19 with NGULNBs (M-21) (M-22).
4. Construct heaters H-362, H-363, H-364, and H-2412 with NGULNBs (M20).

PP. 40 CFR Part 51, Appendix P, Minimum Emission Monitoring Requirements (FCCU)

Appendix P of 40 CFR Part 51 sets forth the minimum requirements for continuous emission monitoring and recording that each State Implementation Plan (SIP) must include in order to be approved under the provisions of 40 CFR §51.165(b). Paragraph 2.4 of Appendix P to 40 CFR Part 51 requires that: "Each catalyst regenerator for fluid bed catalytic cracking units of greater than 20,000 barrels per day fresh feed capacity shall install, calibrate, maintain, and operate a continuous monitoring system for the measurement of opacity which meets the performance specifications of Paragraph 3.1.1 of Appendix P to 40 CFR Part 51". Following the December 2003 expansion of the Artesia refinery's FCCU as authorized by permit 195-M-15, the catalyst regenerator for the FCCU is subject to the minimum requirements for continuous emission monitoring and recording set forth in Appendix P to 40 CFR Part 51, and therefore, shall comply immediately with all applicable provisions, including but not limited to, the emissions monitoring, recording, and reporting requirements; performance specifications for accuracy, reliability, and durability of acceptable monitoring systems; techniques to convert emissions data to units of the applicable standard (opacity limits in 40 CFR §60.102(a)(2), NSPS Subpart J); and the minimum data reporting requirements set forth in Paragraph 4.0 of Appendix P to 40 CFR Part 51 that are necessary to comply with 40 CFR §51.214(d) and (e), which includes, but is not limited to, written reports for excess emissions for each calendar quarter. (M-17)

QQ. Resumed Operation of B-105 for Backup Steam Supply
[REQUEST REVISED. B-6 DAMAGED BEYOND REASONABLE REPAIR]
The combined permitted capacity of boilers B-7 and B-8 shall not exceed 473 MMBtu/hr. Due to the installation of NOx controls, the design capacity of these boilers has not been realized and the refinery has a shortage of steam which is particularly critical when one of these two boilers is off-line. This condition authorizes Navajo to resume operation of Boiler B-105 provided this unit is retrofitted prior to returning to service with NOx controls meeting the same 0.06 lb/MMBtu requirement as for B-7 and B-8.

No increase in the combined allowable emission rate is sought since the total fired duty for the three boilers shall not exceed 473 MMBtu/hr (i.e., the combine fired duty and emission rates for the three boilers will be capped at the allowable rates already authorized for B-7 and B-8). Therefore, the resumption of boiler B-105 operation shall be permitted so long as compliance with the Table 1 combined emissions limit is assured as demonstrated by limiting the combined firing rate of B-105, B-7 and B-8 to =473 MMBtu/hr and the unit's burners are retrofitted to achieve 0.06 lb/MMbtu. Fuel gas flow and/or steam production rates may be used to demonstrate the combined firing rate of B-105, B-7 and B-8. (M-17)

RR. ~~New Storage Tanks T-811 and T-812~~
~~Each of the two new 90,000 barrel hydrocarbon storage tanks T-811 and T-812 shall be equipped with an external floating roof, double seals and the other equipment specified by the TANKS 3.1 emission calculation to reduce VOC emissions to the atmosphere. The maximum true vapor pressure of any volatile organic liquid stored in either tank T-811 or T-812 shall not exceed 11.0 psia. (M-19)~~ [OBSOLETE - These tanks were never constructed.]

SS. 2007 Refinery Expansion Project Best Available Control Technology (BACT) Requirements: (PSD-NM-0195-M25)

- NO_x - The proposed steam-methane reformer furnace (H-H2-2) shall be equipped with a selective catalytic reduction (SCR) control system to reduce NO_x emissions to 0.0125 lb per MM Btu (LHV basis) on a 3-hour rolling average basis at 3% excess oxygen. The SCR exhaust is limited to 7 ppmv ammonia slip, measured on a wet basis. During startup, shutdown, schedule maintenance or malfunction of the SCR control system, BACT for (H-H2-2) shall be ultra low NOx burners emitting no more than 0.03 lb per MMBtu (LHV) on a 3-hour rolling average basis at 3% excess oxygen.
- NO_x - The other proposed process heaters (ROSE2-HOH, HCKR-FRN1, HCKR-FRN2,

HCKR-BOIL1, HCKR-BOIL2, and SRU3-HOH) shall be equipped with NGULNBs emitting no more than 0.03 lb NO_x per MM Btu (LHV basis) on a 3-hour rolling average basis at 3% excess oxygen.

- CO – The proposed steam-methane reformer furnace (H-H2-2) and the ROSE2 hot oil heater (ROSE2-HOH) are each limited to 0.06 lb CO per MM Btu (LHV basis) on a 3-hour rolling average basis.
- CO - The other proposed process heaters (HCKR-FRN1, HCKR-FRN2, HCKR-BOIL1, HCKR-BOIL2, and SRU3-HOH) are each limited to 0.09 lb CO per MM Btu (LHV basis) on a 3-hour rolling average basis.
- VOC – The proposed combustion sources shall exclusively combust gaseous fuels.
- PM_{10} – The proposed combustion sources shall exclusively combust gaseous fuels.
- SO_2 – Fuel sulfur limit shall not exceed 60 PPM H_2S 365-day rolling average.
- SO_2 – The proposed Sulfur Recovery Unit No. 3 Tail Gas Incinerator (SRU3-TGI) is limited to 192 ppmvd SO2 at zero percent oxygen on a 12-hour rolling average basis. In addition, SRU3-TGI is initially limited to 192 ppmvd SO2 at zero percent oxygen on a 365-day rolling average basis. Within 120 days after completing 18 months of operation, Navajo shall submit a permit revision application proposing a new 365-day rolling average limit based on data collected during the initial 18 months of operation.
- VOC – The proposed naphtha storage tank (NAP-TK) and sour water storage tank (NEW-SOURTK) shall be equipped with an external floating roof using double seals to reduce VOC emissions to the atmosphere. The maximum true vapor pressure of any volatile organic liquid stored in either tank shall not exceed 11.0 psia.
- VOC – All fugitive piping components in VOC service associated with the proposed process units shall be monitored under the MACT subpart CC leak detection and repair program, or an approved equivalent program, to reduce VOC emissions.
- VOC – Consistent with MACT Subpart CC, the gasoline truck loading rack shall be limited to 10 mg of VOC emissions per liter of gasoline loaded,
- VOC – The proposed oil-water separator shall be covered and the vapor space vented to a carbon canister system to reduce VOC emissions.
- PM_{10} – The proposed cooling tower shall be equipped with high-efficiency drift eliminators to reduce PM_{10} emissions.
- During heater startup and shutdown, Navajo shall implement each heater's Burner Management System

The following BACT work practices and equipment shall apply to the new SRP (SRU3/TGTU3/TGI3):

- Maintain at least 98% SRP on-stream operations. This includes curtailing refinery operations as necessary when SRU capacity is limited during planned startup, shutdown, and maintenance events.
- Construct a 20,000 barrel sour water storage tank in addition to the existing 10,000 barrel tank.

- Maintain adequate SRP excess capacity to reduce the frequency and quantity of refinery excess SO2 emissions. After the refinery expansion project proposed units are constructed, the proposed SRU3 will provide at least 25% excess capacity.
- Continue to maintain and use a sulfur shedding plan to prevent or reduce acid gas flaring events from refinery upsets. An acid gas flaring event is defined as excess SO_2 emissions greater than 500 pounds in a 24-hour period. The plan shall state specific actions that may be taken to reduce or prevent acid gas flaring. The actions taken during any event will be based on the refinery operators' discretion, considering safety and other factors related to prudent operation. This plan is subject to review by NMED or EPA, and shall be amended upon written request by NMED or EPA. The sulfur shedding plan may included, but is not limited to the following options:
  a. Store sour water to reduce acid gas generation from the sour water strippers
  b. Reduce the operating rate of one or more amine strippers to lower the acid gas generation rate
  c. Reduce one or more hydrotreating unit throughput rates to lower acid gas generation rate.
- Use hydrogen, when available, as SRU fuel during startup and hot standby to minimize carbon deposits on the SRU catalysts.
- During startup and shutdown process vessels shall be depressurized into other process equipment rather than venting to a flare. The permittee shall document instances when this is not practicable.

The following BACT work practices shall apply to the new flare (FL-405):

- The flare shall be used only for controlling startup, shutdown, maintenance, or malfunction emissions and is not authorized for controlling routine process vents.

TT. New Storage Tanks T-0078 and T-0079

Each of the two new hydrocarbon storage tanks T-0078 and T-0079 (50,000 bbl and 80,000 bbl, respectively) shall be equipped with an external floating roof, double seals and the other equipment specified by the AP-42 Chapter 7.1 (Nov. 2006) emission calculation to reduce VOC emissions to the atmosphere. The maximum true vapor pressure of any volatile organic liquid stored in either tank T-0078 or T-0079 shall not exceed 11.0 psia. (M25-R2)

3. Refinery Emission Limits

The non-exempt emission sources at the refinery shall consist only of the sources listed in Table I and Tables 2A through 2G of this permit. (2.e)

A) The allowable hourly and yearly emission rates associated with the equipment listed in Table I for the equipment whose installation predates the effective date of 20.2.72 NMAC (August 31, 1972) and which was not modified since that date shall be taken as the "potential emission rate" of that unit as defined in 20.2.72.107 NMAC and the potential to emit of that unit defined under 20.2.74 NMAC. The allowable hourly and yearly emission limits of all refinery emission sources are as listed in Tables 1 and 2A through 2G. (1.e)

B) In accordance with NSPS Subpart J, the 12-hour rolling average SO_2 concentration from Unit H-473 shall not exceed 250 ppmv each on a dry basis and zero percent excess air. (M-12) (M-15)

C) In addition to operating those sources of air emissions, Navajo Refining may: (1.d, 11.2.a, 12.2, 13.2, 14.2)

1) operate air emission sources used strictly for maintenance of grounds or buildings, including, but not limited to welding, painting, general repairs, grinding, woodworking, and cutting; and controlling pests; (1.d)

2) operate mobile air emission sources, including but not limited to forklifts, front end loaders, bulldozers, graders, maintenance and delivery vehicles, cranes; (1.d)

3) refuel mobile sources or small portable equipment; (1.d)

4) operate building space heaters. (1.d)

D) The following shall apply to boilers B-7 and B-8:

1) In accordance with 20.2.33.108.A NMAC, NO_x emissions from boilers B-7 and B-8 shall not exceed 0.2 lb/MMBTU.

2) In accordance with the Consent Decree lodged December 20, 2001, NO_x emissions from boilers B-7 (no later than December 31, 2002) and B-8 (no later than December 31, 2003) shall not exceed the limit in Table 1 on any rolling 3-hour sampling period. Demonstration of compliance with the NOx limit for B-7 and B-8 shall be established by averaging the CEMS Data over any 3-hour period and comparing the average concentration to the parametric limit of = 42.1 ppm NO_x, corrected to 6.1% O_2 as determined by the CEMS installed pursuant to permit condition 4.Q.1. (M-17; CD ¶16.D)

E) Emissions from H-9, H-11 and H-421 shall not exceed the values stated in Table 1.

F) Pursuant to Application 195-M-15 (GOHT Application) H_2S in the fuel gas for heaters H-9, H-11, H-18, H-19, H-20, H-21, H-28, and H-601 shall not exceed 0.05 grains/dscf on a rolling 12-month average basis. (M-21)

G) <u>Consent Decree Limits on PM and SO_2 emissions from the FCCU:</u>

By no later than December 31, 2003, the WGS on the FCCU Regenerator shall comply with the following limits: (M-17; CD ¶12.B & ¶13.B)

1. SO_2 concentration not to exceed 25 ppmvd on a 365-day rolling average basis and 50 ppmvd on a 7-day rolling average basis, each corrected to 0% oxygen. Compliance with this emissions limit shall be demonstrated on an ongoing basis through the use of CEMS (permit condition 4.M); and
2. A particulate matter (PM) emission limit of 1.0 pound of PM per 1000 pounds of coke burned on a 3-hour average basis (CD ¶13.B).
3. As the FCCU Regenerator is subject to the provisions of 40 CFR § 60.102 (NSPS Subpart J), it shall not discharge to atmosphere gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one-hour period.

H) <u>Consent Decree Limits on NO_X and CO emissions from the FCCU:</u>
The FCCU shall comply with NO_X and CO emission limits as follows:

1. The concentration-based (ppmvd) NO_X emission limit based on 3-hour rolling and 365-day rolling averages, corrected to 0% oxygen as established pursuant to permit condition 2.DD, unless EPA rejects the proposed limit and establishes a different NOx emission limit, in which case the FCCU shall comply with EPA's established limit. Under no circumstances shall this emission limit be greater than a concentration-based limit that would be equivalent to 34.9 lbs/hr. The 3-hour FCCU NOx emission limits, whether established pursuant to permit condition 2.DD or by EPA, shall not apply during periods of Hydrotreater Outage provided that the FCCU (including associated air pollution control equipment) is maintained and operated in a manner that minimizes emissions in accordance with an EPA-approved good air pollution control practices plan. Navajo shall comply with the plan at all times, including periods of startup, shutdown, and malfunction of the hydrotreater. The 365-day rolling average NOx emissions limit shall apply during periods of hydrotreater outages. (M-17; CD ¶11.E.i, ¶11.E.ii, & ¶11.G)
2. The NSPS Subpart J emission limit of 500 ppmvd CO corrected to 0% O_2 on a 1-hour average basis and 100 ppmvd CO corrected to 0% O_2 on a 365-day rolling average basis, by no later than December 31, 2003. (M-17; CD ¶14.B)

I) <u>Establishing NO_X Emissions Limits for Controlled Heaters</u>
Within 120 days after startup of operations of each NOx controlled heater (as identified at permit condition 2.OO.1), a permit revision application shall be submitted under 20 2.72.219(D) NMAC to propose NO_X permit emissions limits in lbs/MMBTU on a 3-hour average basis. The proposed permit limit shall be based on actual performance as demonstrated by performance tests and, if applicable CEMS data, and shall be low enough to ensure proper operation of the NO_X Control Technology and high enough to provide a reasonable certainty of compliance. (M-17;

CD ¶16.D). The following combustion sources shall not exceed the 3-hour rolling average lb NOx per MM Btu limits listed in Table 1:

- Heater H-601 (M-17, CD ¶16.D, 05/14/2004 report of 03/02/2004 test results) (Supersedes previous Condition 3.E.1 for H-601)
- Heaters H-352, H-353, H-354, and H-20 (M-25)
- Heater H-600 (CD ¶16.D, M25-R2)

J) In addition to the controlled heaters identified in the Consent Decree, the following combustion sources shall not exceed the 3-hour rolling average lb NOx per MM Btu limits listed in Table 1:

- Heaters H-362, H-363, H-364, and H-2421 (M-20).
- Heater H-19 (M-21)
- Heater H-H2 (M-22)
- Heaters H-H2-2, ROSE2-HOH, HCKR-FRN1, HCKR-FRN2, HCKR-BOIL1, HCKR-BOIL2, and SRU3-HOH (M-25)

4. Monitoring of Operations

A. A VOC Leak Detection, Maintenance and Repair (LDMAR) program, utilizing the methods found in 40 CFR 60 Subpart GGG, shall be implemented for the VOC-service equipment within the battery limits of the relocated Alkylation Unit, (including equipment associated with the added butane treater), the existing VOC-service equipment in the North Division Crude Unit, the VOC service equipment in Cooling Tower Y-7 (redesignated as Y-8), the CBG components, the Naphtha Light Oil (FUG-BLND) fugitive components, the existing naphtha unit including those components associated with the naphtha splitter project fugitive components, and the existing and proposed components (FUG-02, FUG-08, FUG-18, & FUG-35) associated with the PTRP are subject to Navajo's VOC Leak Detection, Maintenance and Repair (LDMAR) program. This VOC LDMAR program has been placed in the permit in accordance with Navajo's request and in accordance with 20.2.74 and 20.2.72 NMAC, section 210.B.1.b, in order to make the LDMAR offsets used for netting under the PSD regulation federally enforceable. (M-3) (13.1.d) (M-17) (M-18) (M-19) (M24-R1) (M24-R4).

B. A continuous SO_2 monitor (SO_2 CEMS) and flow meter shall be installed on Unit H-473, the tail gas incinerator stack of SRU1/SRU2, and the tail gas incinerator stack of SRU3 (SRU3-TGI). The monitor shall complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15 minute period or less. One-hour averages shall be computed from four or more data points equally spaced over each one-hour period. The data from the SO_2 stack gas monitor and flow meter shall be analyzed on an hourly basis for SO_2 concentration and volume flow rate. CEMS readings obtained during calibration of the instrument shall be excluded from the averages used to determine compliance. (M-4) (12.1.b.2, 12.4.a). (M-12) (M-15) (M-25)

C. A flow meter shall be installed on the sour water stripper streams into:
- SRU1. (M-4) (12.1.b.2)
- SRU2. (M-12) (12.4.a)
- SRU3 (M-25)

D. The gas stream feeding SRU1, SRU2, and SRU3 from the amine regeneration units and the sour water stripper shall be initially tested daily (excluding weekends and holidays) for H_2S concentration. If data submitted by Navajo indicates a different sampling frequency is justified, the Department may change the sample period for the upstream analyses. (M-12) (12.4.a) (M-25)

E. Calibration. The SO_2 CEMS and flow meter on the SRU1/SRU2 and SRU3 incinerator stacks, and the instruments used to measure sulfur concentration and flow rates of the gas streams into SRU1, SRU2, and SRU3, shall be calibrated and maintained at a frequency and method specified by the manufacturer. (M-4) (12.7) (M15)

In addition, the SO2 CEMS shall follow the quality assurance and quality control procedures in 40 CFR 60 Subpart J and Appendix F.

F. An alarm system in good working order shall be connected to Flare FL-403 which will signal non-combustion of the gas. (M-5-Rev.) (11.1.e)

G. **[COMPLETE]** Within ninety (90) days of the date of Permit No. 195-M-6 (March 13, 1996), Navajo shall submit for Department approval a plan to meter all acid gas, in standard cubic feet (SCF) per hour, sent to flare FL-403. The flow meter shall be operated continuously 24 hours per day, 365 days per year except for periods of flow meter maintenance or repair. The upper range of the flow meter shall be sufficient to record the highest expected flow rate of acid gas sent to flare. Navajo Refining will provide the Department with the minimum sensitivity of the flow meter as part of the plan to be submitted to the Department. Within the limits of technical feasibility and cost, the sensitivity of the flow meter shall be as close as possible to 50 SCF per hour, equivalent to about 4 pounds per hour of H_2S. (M-6) (1.f.iii)

[ONGOING] The flow meter shall be operated and calibrated at a frequency and by the procedure specified by the manufacturer. A chart recorder or data logger (electronic storage) shall keep a continuous and permanent record of the amount of gas measured by the flow meter. (M-6) (1.f.iii)

H. **[CANCELLED]** ~~The VOC and benzene emissions from the 70-gallon-per-minute groundwater stripper shall be determined using the concentration and volume flow of the inlet and outlet water streams to the stripper. The emissions shall be determined once per month the same day of the week (for example the second Wednesday of every month) at approximately the same time of~~

~~day. Navajo shall submit a test plan for Department approval within ninety (90) days of the date of Permit No. 195-M-7. (M-6) (5.d), (M-7)~~

I. Data Capture. The minimum acceptable level of data capture for all instruments measuring flow and concentration of sulfur streams into the SRU1, SRU2, and SRU3 including the CEMS and flow meters on the incinerator stacks shall be at least 90% for each month. The 10% lost data will include all periods when the concentration and corresponding flow are not being measured as a result of calibrations or breakdowns. (M-4) (12.1.b.2)

J. The fuel gas required to provide supplemental heat to either Flare FL-400 or FL-403 as required under Condition 2.J shall be monitored during flaring by a flow meter. The flow meter shall be operated continuously 24 hours per day, 365 days per year except for periods of flow meter maintenance or repair. The upper range of the flow meter shall be sufficient to record the highest expected flow rate of fuel gas sent to flare. The reading of this flow meter and the flow meter to measure acid gas flow as required under Condition 4.G shall be used to determine compliance with Condition 2.J.

K. Leak detection and monitoring of the Amine treating/regeneration area shall be performed according to the requirements stipulated in 40 CFR 60, Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries. Specifically, Navajo Refining Company shall meet the requirements, as applicable, of §60.592 - Standards, which references §60.482-1 to §60.482-10 and §60.483 to §60.487 of 40 CFR 60, Subpart VV, with the additional enhancements described in Condition 5.I.7. (M-17)

L. Unless or until Navajo implements another EPA-approvable alternative monitoring procedure (AMP), CCR off-gas streams that enter the refinery fuel gas system downstream of the H_2S CMS shall be monitored for H_2S as follows:

a) CCR stabilizer off gas stream once per shift by Draeger Tube
b) H_2 recycle gas stream once per day by Draeger Tube
c) CCR feed stream once per day by Houston-Atlas analyzer

If any Draeger Tube analysis exceeds 40 ppm, a gas sample will be collected for verification by the Houston Atlas analyzer. If the Houston Atlas analysis yields H_2S results greater than 40 or 160 ppm, samples will be collected every three hours until the H_2S concentration decreases to below 40 ppm.

M. By no later than December 31, 2003, a continuous emissions monitor system (CEMS) for CO, O_2, SO_2 and NO_x shall be installed, calibrated, maintained, and operated on the FCC Catalyst Regenerator vent stack(s) downstream of the scrubber in accordance with 40 CFR Part 60, §60.13, Appendix A, and the applicable performance specifications of Appendices B (Specifications 2 and 3) and F. The CEMS shall be used to demonstrate compliance with emissions limits and to report compliance with the terms and conditions of the Consent Decree. The CEMS and process data shall be made available, by permittee, to applicable Federal and State Agencies (NMED) upon demand as soon as practicable. (M-17; CD ¶11.F, 12 D, and 14.C)

N. Certain added equipment components within battery limits of the FCCU process area are subject to the MACT Subpart CC monitoring requirements and will be incorporated into the existing MACT LDMAR program for FCCU components (i.e., FUG-FCCU). Equipment components added within battery limits of the amine process area will be incorporated into the existing LDMAR program for amine unit components (i.e., FUG-AMINE). The following process unit fugitive source areas, certain equipment may be in HAP service and subject to the MACT Subpart CC monitoring requirements. Therefore the fugitive sources in HAP service for the following areas shall be incorporated into the existing MACT CC LDMAR program:

- JP-8 unit, when in naphtha hydrotreating operation, (FUG-06-NHDU) (M20).
- South Crude Unit (FUG-02-SP CRUDE) (M21).
- Hydrogen Plant (FUG-63-H2 PLANT-1) (M22).
- Naphtha Unit 06 (FUG-06-NHDU) (M24-R1).
- PTRP (M24-R4)
- 2007 refinery expansion project units (FUG-31-SRU3/TGTU3/TGI3, FUG-34-Hydrocracker, FUG-SAT GAS-2, FUG-25-ROSE-2, FUG-64-H2-PLANT-2)(M-25).

In addition, as BACT, VOC sources in the 2007 refinery expansion project that are not subject to MACT Subpart CC shall be included in the MACT CC LDAR monitoring program to minimize VOC emissions.

O. <u>CEMS to Monitor SO_2 Emissions from the Tail Gas Incinerators (H-473 and TGI3)</u>
Tail gas incinerator SO_2 emissions from the SRPs shall be monitored during all periods of operation of the Artesia SRPs, and excess emissions reported by the permittee, as required by 40 CFR §§ 60.7(c), 60.13, and 60.105(a)(5). The permittee shall continue to conduct emission monitoring from the SRPs with CEMS at all of the tail gas emissions points, unless an SO_2 alternative monitoring procedure has been approved by EPA, per 40 CFR § 60.13(a), for any of the emissions points. (M-17; CD ¶18.C.ii,M-25)

P. <u>Fuel Gas CMS to Demonstrate Compliance with NSPS Subpart J and PSD BACT Requirements for Fuel Gas Combustion Devices (Flares, Heaters, and Boilers)</u>

i) To comply with NSPS Subpart J, 40 CFR § 60.105(a), and the PSD BACT requirements of the 2007 refinery expansion project, the permitee shall install, calibrate and maintain a continuous monitoring system (CMS) to continuously measure and record either the hydrogen sulfide (H_2S) in the refinery fuel gas streams being burned in the Heaters and

Boilers or the concentration of sulfur dioxide emissions to the atmosphere.

ii) Flaring Devices which combust routinely-generated refinery fuel gases shall be equipped with a CEMS as required by 40 CFR § 60.105(a) or with a parametric monitoring system approved by EPA as an alternative monitoring system under 40 CFR § 60.13(i). The permittee shall comply with the reporting requirements of 40 CFR Part 60, Subparts A & J for such Flaring Devices. (M-17; CD ¶19.D, M-25)

Q. <u>Testing and Monitoring NOx Emissions from Controlled Heaters and Boilers subject to the Consent Decree</u>

For the Controlled Heaters and Boilers as listed in the Consent Decree, continuous compliance with their respective NO_x permit emissions limits shall be demonstrated by monitoring as follows: (M-17; CD ¶16.C)

1. For heaters and boilers (including B-7 & B-8) with a heat input capacity greater than 150 MMBTU/hr of HHV, the permitee shall install or continue to operate CEMS to measure NO_x and O_2 no later than the date of installation of the applicable NO_x Control Technology (permit Condition 2.OO) on the heater or boiler. Each CEMS shall be installed, certified, calibrated, maintained, and operated in accordance with the requirements of 40 CFR §§ 60.11, 60.13, and Part 60 Appendix A and the applicable performance specification test of 40 CFR Part 60 Appendices B and F. These CEMS will be used to demonstrate compliance with emission limits. The permittee shall make CEMS and process data available to the applicable Federal and State Agencies upon demand as soon as practicable; (M-17; CD ¶16.C.i)

2. For heaters and boilers with a heat input capacity of equal to or less than 150 MMBTU/hr (HHV) but greater than 100 MMBTU/hr (HHV), Navajo shall (a) install or continue to operate CEMS to measure NOx and O_2 by no later than the date of the installation of the applicable NOx Control Technology on the heater or boiler (Permit Condition 2.OO); or (b) submit for EPA approval, by no later than 60 days after the date of installation of the applicable NOx Control Technology on the heater or boiler, a proposal for monitoring based on operating parameters, including but not limited to, firebox temperature, air preheat temperature, heat input rate, and combustion O_2; Navajo shall evaluate the necessity of using firebox or bridgewall temperatures and additional operating parameters and agrees to use such parameters as a means of monitoring performance where Navajo and EPA mutually-agree to their effectiveness; and (M-17; CD ¶16.C.ii) This condition currently includes the following heaters and boilers:

   - (None as of M-25)

3. For heaters and boilers with a heat input capacity of equal to or less than 100 MMBTU/hr of HHV (e.g., Heaters H-20, H-600, and H-601), the permittee shall, no later than 60

days after the date of installation of the applicable NO_x Control Technology (permit Condition 2.OO), conduct an initial performance test. The results of this test shall be reported based upon an average of three (3) one-hour testing periods and shall be used to develop representative operating parameters for each unit, which will be used as indicators of compliance. (M-17; CD ¶16.C.iii). This condition currently includes the following heaters and boilers:

- Heaters H-352, H-353, and H-354 (M-20)
- Heater H-20 (M-21)
- Heaters H-600 and H-601

4. For heater H-601 compliance shall be indicated by continuously monitoring stack oxygen (O_2) to maintain a 3-hour average below 6.0 vol%. As a further check of compliance, Navajo will monitor stack NOx at least twice a month using a portable analyzer to assure that the measured NOx value does not exceed the compliance threshold of 38 ppmv NOx. (M-17; CD ¶16.C.iii)

R. Testing and Monitoring NOx Emissions from Heaters and Boilers permitted after the Consent Decree

For the Heaters and Boilers permitted after the Consent Decree, continuous compliance with their respective NO_x permit emissions limits shall be demonstrated by monitoring as follows:

1. For heaters and boilers with a heat input capacity greater than 150 MM Btu/hr (LHV Basis), the permittee shall install and operate CEMS to measure NO_x and O_2 by the start up date of each heater or boiler. Each CEMS shall be installed, certified, calibrated, maintained, and operated in accordance with the requirements of 40 CFR §§ 60.11, 60.13, and Part 60 Appendix A and the applicable performance specifications of 40 CFR Part 60 Appendices B and F. These CEMS will be used to demonstrate compliance with emission limits. The permittee shall make CEMS and process data available to the applicable Federal and State Agencies upon demand as soon as practicable. This condition currently includes the following heaters and boilers:

   - Heaters H-H2-2 (M-25)

2. For heaters and boilers with a heat input capacity of equal to or less than 150 MM Btu/hr (LHV) but greater than 100 MM Btu/hr (LHV), Navajo shall:
   (a) install and operate CEMS to measure NOx and O_2 by the start up date of each heater or boiler; or
   (b) submit for NMED approval, by no later than 90 days after the start up date of each heater or boiler, a proposal for monitoring based on operating parameters. Operating parameters to consider include, but are not limited to, firebox temperature, air pre-heat

temperature, heat input rate, and combustion O_2. Navajo agrees to use such parameters as a means of monitoring performance.

This condition currently includes the following heaters and boilers:
- Heater H-H2 (M-22)
- Heater ROSE2-HOH (M-25)

3. For heaters and boilers with a heat input capacity of equal to or less than 100 MM Btu/hr (LHV basis), the permittee shall conduct an initial performance test by no later than 180 days after the start up date. The results of this test shall be reported based upon an average of three (3) one-hour testing periods and shall be used to develop representative operating parameters for each unit, which will be used as indicators of compliance. This condition currently includes the following heaters and boilers:

   - Heaters H-362, H-363, H-364, and H-2421 (M-20)
   - Heater H-19 (M-21)
   - Heaters HCKR-BOIL1 and HCKR-BOIL2 (M-25)

S. Cooling tower monitoring (Unit CT-Y9):
1. The proposed cooling tower high-efficiency drift eliminators shall be visually inspected for structural integrity annually. The cooling tower water shall be sampled and tested for total dissolved solids (TDS) on a quarterly basis.
2. The permittee shall monitor the cooling water inlet and outlet streams for hydrocarbons on an annual basis using either EPA Method 8015 with a large enough sample to achieve accurate quantification of hydrocarbon content, EPA Method 8260, EPA Method 8270 or a similar method as approved by the Department prior to testing. (M-25)

5. 20.2.77 NMAC - Federal New Source Performance Standards (NSPS)

The Department has identified the following boilers, heaters, tanks, VOC fugitive components, and wastewater systems as being subject to the federal NSPS, 40 CFR Part 60. The Department believes this list to be accurate and complete. However, failure of this permit to list all sources subject to federal NSPS does not relieve Navajo Refining from complying with any and all terms of the federal NSPS. Where the NSPS allows alternate methods of emission control, recordkeeping, or reporting, these methods may be implemented in accordance with the NSPS provisions.

A NSPS Subpart A, "General Provisions", 40 CFR 60.1

Navajo Refining shall comply with Subpart A, including but not limited to:
1. In accordance with 60.7 for any affected facility, as the term is defined in 40 CFR 60.2, notification of the date of commencement of construction, the actual date of initial startup,

and notification of any physical or operational change that may increase the emission rate of a regulated pollutant.

2. In accordance with 60.7 for any affected facility, as the term is defined in 40 CFR 60.2, maintain **records** of the occurrence and duration of any startup, shutdown or malfunction of an affected facility; maintain **records** of malfunction of air pollution control equipment; and maintain **records** of any periods during which a required CEM (such as the H_2S fuel gas monitor) is inoperative.

3. In accordance with 60.7, submit excess emissions **reports** for excess emissions from affected facilities.

4. In accordance with 60.11(d), implement good air pollution control practices to minimize Hydrocarbon (HC) and Acid Gas (AG) Flaring Incidents. (M-17; CD ¶19.C)

5. Flare FL-405 shall comply with the applicable requirements of 40 CFR 60.18 General control device requirements.

B NSPS Subpart Db, "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units"

Permit Number	Affected Heater or Boiler
195-M-14	Boilers B-7 and B-8
195-M-25	ROSE2-HOH

C NSPS Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units"

Permit Number	Affected Heater or Boiler
195-M-9-R-3	Heater H-444 [Suspended Indefinitely]

D NSPS Subpart J, "Standards of Performance for Petroleum Refineries"

Permit Number	Affected Heater or Flare
195-M3	70-H1/2/3 (redesignated as H-352, H-353, H-354), 70-H4 (redesignated as H-355), and H-40, FL-403 (14.3.a)
195-M4	H-460 and H-463 (12.3.a)

195-M5-Rev.	H-21 (formerly H-421) (11.3.a)
195-M6	H-18 (3)
(Consent Agreement, permit pending)	H-28 (replaced H-10 in 1993)
195-M7/M12	Sulfur Recovery Plant is comprised of two Claus Sulfur Recovery Units (nominally rated SRU2 – 100 LTD and SRU1 – 40 LTD) with treating unit and tail gas incinerator (nominally rated TGU – 70 LTD) and Unit H-473. (M-12, CD ¶18.A)
195-M9	Boiler B-6 (Replaced Boiler B-3)
195-M9-R-3	Heater H-444 [Suspended Indefinitely]
195-M14	Heater H-30, Boilers B-7 and B-8
195-M15	Heaters H-601, H-20, Flare FL-404
195-M15-R2	Hot Oil Heater H-464
195-M17	All remaining process heaters, boilers, and flares which combust gases generated at the refinery including B-105, and H-SDA. (M-17; CD ¶17.B & ¶19.A)
195-M17	Beginning December 31, 2003, the FCCU Catalyst Regenerator for the following pollutants: SO_2, CO, PM, opacity [40 CFR §60.100 (b)] (M-17; CD ¶15)
195-M20	Heaters H-362, H-363, H-364, and H-2421 and option for oxygen enrichment increasing SRU nominal capacity to 130 LTPD (M-20)
195-M21	Heater H-19 (H-20 already included by 195-M-15) (M-21)
195-M22	Heater H-H2 (M-22)
195-M25	ROSE2-HOH, HCKR-FRN1, HCKR-FRN2, HCKR-BOIL1, HCKR-BOIL2, H-H2-2, SRU3-HOH, H-473, SRU3-TGI, FL-405

Navajo Refining shall comply with Subpart J, including but not limited to:

1. In accordance with 60.104, the fuel gas to be combusted in affected heaters and affected flare pilots shall be sweetened refinery fuel gas with a maximum H_2S concentration of 0.1 grain/DSCF; (12.3.a)

2. In accordance with 60.105, the H_2S concentration of the refinery fuel gas supplied to the affected heaters or flare pilots shall be monitored by a continuously recording H_2S monitor; (14.3.a)

3. The H_2S monitor shall be operated, maintained, and certified in accordance with 60.105;

4. In accordance with 40 CFR Section 60.104, the SRUs with tail gas cleanup unit together with the tail gas incinerator shall not discharge any gases into the atmosphere greater than

250 ppmv (dry basis) of sulfur dioxide on a 12-hour rolling average at zero percent excess air except during start-up, shutdown or malfunction of the SRPs, or during malfunction of the TGTU. For the purpose of determining compliance with the SRPs' emissions limits of 40 CFR § 60.104(a)(2), the 'start-up/shutdown' provisions set forth in NSPS Subpart A shall apply to the SRPs and not to the independent start-up or shutdown of the TGTU. However, the malfunction exemption set forth in NSPS Subpart A shall apply to both the SRPs and the TGTU. (CD ¶18.B.i and ¶18.C.i)

5. The combustion of gases generated by the start-up, shutdown or malfunction of a refinery process unit or released to a Flaring Device as a result of relief valve leakage caused by excessive pressure build-up or other emergency malfunction shall be exempt from the requirement to comply with 40 CFR § 60.104(a)(1). (CD ¶19.B.ii)
6. Any other applicable requirement of NSPS Subpart J.

E NSPS Subpart K, "Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978".

Permit Number	Affected Tank
No permit	T-437, T-838

Navajo Refining shall comply with Subpart K, including but not limited to:

1. In accordance with 60.112, an affected tank storing a petroleum liquid which has a true vapor pressure $\geq$1.5 psia but $\leq$11.1 psia shall be equipped with any of: an external floating roof, a vapor recovery system, or their equivalents. If the true vapor pressure is $\geq$11.1 psia, the storage vessel shall be equipped with a vapor recovery system or equivalent;

2. In accordance with 60.113, Navajo Refining shall maintain for all affected tanks a record of the petroleum liquid stored, the period of storage, temperature during the storage period, and the maximum true vapor pressure of that liquid during the respective storage period;

3. Any other applicable requirement of Subpart K shall be observed.

In accordance with 60.113 (c), tanks storing petroleum liquids whose true vapor pressure is always <1.0 psia are exempt from the requirements of Subpart K.

F NSPS Subpart Ka, "Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984".

Permit Number	Affected Tank
195	T-439 (17)
195-M-1	T-401 and T-402 (18)
195-M-6	T-435
No permit	T-124, T-400, T-434, T-438

Navajo Refining shall comply with Subpart Ka, including but not limited to:

1. In accordance with 60.111a, No. 2 through No. 6 fuel oil or gas turbine fuels 2-GT and 4-GT, and diesel fuels 2-D and 4-D are not considered petroleum liquids for applicability of Subpart Ka. Therefore tanks which otherwise would be subject to Subpart Ka are exempt from the requirements of the subpart;

2. In accordance with 60.112a, an affected tank storing a petroleum liquid which has a true vapor pressure $\geq$ 1.5 psia but $\leq$11.1 psia shall be equipped with any of: an external floating roof with a double seal closure, an internal floating roof with a single seal closure, or a vapor recovery system;

3. In accordance with 60.113a, for external floating roof tanks: periodically measure seal gaps, keep records of gap measurements, report to the Department tanks that do not meet the gap requirements of 60.112a, and provide the Department at least 30 days notice prior to any gap measurement so that a Department observer may be present;

4. In accordance with 60.115a, maintain appropriate records for each affected tank, including the liquid stored, the period of storage, and the maximum true vapor pressure of the liquid during its storage period;

5. Any other applicable requirement of Subpart Ka shall be observed

G NSPS Subpart Kb, "Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After January 23, 1984"

Permit Number	Affected Tank
195-M5-Rev.	T-450 (Construction of this tank was re-authorized on May 6, 1997. Increase in throughput and vapor pressure of material stored in this tank

	are authorized in permit No. 195-M-7.)
No permit	T-13-S, T-128, T-834
195-M9-R3	**[SUSPENDED INDEFINITELY**] Two 2000 barrel polymer concentrate tanks
195-M14-R2	T-802
195-M15-R1	2 new 100,000 BBL (est) gas oil storage tanks – exempt from permitting because the vapor pressure is well below the 0.2 psia threshold for exemption criteria under 20.2.72 202.B.2 NMAC (recordkeeping requirements of Kb only)
195-M18-R1	Diesel storage tank T-815
195-M19	~~2 new 90,000 BBL (est.) storage tanks T-811 and T-812~~ [Never constructed]
195-M25	naphtha storage tank (NAP-TK), sour water storage tank (NEW-SOURTK), pitch tanks (PITCH-TK1, PITCH-TK2)
195-M25-R2	New 50,000 bbl and 80,000 bbl storage tanks (T-0078 and T-0079) to be constructed instead of T-811 and T-812.

Navajo Refining shall comply with Subpart Kb, including but not limited to:

1. In accordance with 60.11~~2~~0b, an affected tank whose design capacity is ≥950 BBL containing a volatile organic liquid (VOL) with a vapor pressure ≥0.~~7~~5 psia but <11.1 psia; or an affected tank whose design capacity is ≥472 BBL containing a VOL with a vapor pressure ≥~~4.0~~2.14 psia but <11.1 psia shall be equipped with one of the following: a properly sealed internal floating roof, a double seal external floating roof, or a closed vent system;

2. In accordance with 60.113b, for affected external floating roof tanks, Navajo Refining shall **periodically measure** gap widths, make necessary repairs or empty the tank within 45 days of identification of any tank not meeting the minimum gap requirements, and shall **notify** the Department at least 30 days in advance of any gap measurements so that a Department observer may be present;

3. In accordance with 60.115b, Navajo shall maintain appropriate **records** for each affected tank, including **records** of each tank inspection, and submit appropriate **reports**, including an initial **report** certifying the control equipment, a **report** of the results of any required seal gap measurements, and a **report** containing the particulars of any gap that did not meet the requirements of the subpart and the repairs undertaken;

4. In accordance with 60.116b, maintain appropriate **records** showing tank dimension and capacity, the VOL stored, the period of storage, and the maximum true vapor pressure of the VOL during the respective storage period;

5. For affected vessels containing waste mixtures or mixtures of indeterminate or variable composition, such as slop oil, Navajo shall comply with the requirements of 60.116b (f) regarding the range of vapor pressures;

6. Any other applicable requirement of Subpart Kb shall be observed.

H NSPS Subpart UU, " Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture"

Permit Number	Affected Tank
195-M-9-R-3	Two 2000 barrel polymer concentrate tanks [Suspended Indefinitely]

I NSPS Subpart GGG, "Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries".

Permit Number	Affected Units
195-M2	All VOC-service equipment within the battery limits of the CCR Reformer and in the expanded Naphtha HDS Unit. (14.3.b)
195-M4	All VOC-service equipment within the SRU. (12.3.b)
195-M12	All VOC service equipment within the SRU2/TGU2 and Unit H-473.
195-M15	All VOC-service equipment within battery limits of the GOHT Unit, including the H2 service valves. Also, affected equipment installed within battery limits of other process units modified under 195-M15.
195-M17	Beginning December 31, 2003, NSPS Subpart GGG becomes applicable to the primary FCCU wet gas compressor, C-952. (M17; CD ¶23.D)
195-M20	All VOC-service equipment within the Diesel Hydro-desulphurization Unit (DHDU). (M20)
195-M21	All VOC-service equipment within the South Crude Unit (M21)
195-M22	All VOC-service equipment within the Hydrogen Plant (M22)
195-M24-R1	All VOC service equipment (FUG-06-NHDU) within the existing naphtha unit including those components associated with the naphtha splitter project (M-24-R1)
195-M24-R4	All VOC service equipment associated with the PTRP.
195-M25	All VOC service equipment associated with the refinery expansion.

Navajo Refining shall comply with Subpart GGG, including but not limited to:

1. In accordance with 60.592, Navajo shall comply with the leak detection and monitoring program of 60.482-1 through 60.482-8 for all affected pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, and valves;

2. Delay of repair for leaking components is allowed in accordance with 60.482-9;

3. Control devices used to dispose of VOC leaks from affected closed vent systems shall comply with the requirements of 60.482-10; Flares shall meet 40 CFR 60, Subpart A, Section 60.18.

4. In accordance with 60.486, leaking components shall be visibly tagged and information on leaking components shall be appropriately recorded in a log. A record shall be kept of all components subject to 60.482-1 through 60.482-10 showing: a) ID numbers of all affected components; b) the dates of each compliance test; c) the IDs of valves designated as unsafe-to-monitor and a plan to monitor these valves; d) the IDs of valves designated as difficult-to-monitor and the schedule of monitoring of each valve; and e) any other applicable requirement of 60.486. (12.4.b, 14.4)

5. In accordance with 60.487, Navajo shall submit appropriate semiannual reports to the Department identifying leaking and unrepaired components, explaining any delays of repair, stating dates of process unit shutdowns, filing revisions to the list of affected components, and any other applicable provisions of 60.487. (12.5.b)

6. Any other applicable requirement of Subpart GGG shall be observed.

7. The leak detection and monitoring program of NSPS Subpart GGG shall be enhanced at Navajo's Artesia refinery by implementing the following (M-17; CD ¶23)

   A first attempt at repair shall be made on valves with a reading greater than 200 ppm VOC (excluding control valves or valves for which the monitoring technician is not authorized to repair). No skip period will be provided
   Unless unsafe or technically infeasible, Navajo will attempt "drill and tap" repairs on valves (other than control valves) having leak rates in excess of 10,000 ppm VOC after the initial and second repair attempts (non-drill and tap) have been made. Only after two unsuccessful "drill and tap" attempts have been made will the valve be placed on the delay of repair list.

   By no later than December 20, 2003, Navajo will utilize an internal leak definition of 500 ppm VOC for all valves, excluding pressure relief valves.

   By no later than June 20, 2003, Navajo will utilize an internal leak definition of 2,000 ppm VOC for 50 percent of the total number of monitored pumps (combined number of pumps for all monitoring programs).

By no later than December 20, 2003, Navajo will utilize an internal leak definition of 2,000 ppm VOC for 85 percent of the total number of monitored pumps (combined number of pumps for all monitoring programs).

By no later than April 20, 2004, Navajo will utilize an internal leak definition of 2,000 ppm VOC for all monitored pumps.

Best efforts will be made to isolate and make a first attempt at repair for pumps with a leak rate for 2,000 – 9,999 ppm VOC within 15 days of monitoring.

J NSPS Subpart QQQ, "Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems"

Beginning December 31, 2003, all remaining and newly installed individual drain systems, oil-water separators, and aggregate facilities not previously specified shall be affected facilities, as the term is used in the NSPS, 40 CFR Part 60, and shall be subject to and comply with the requirements of 40 CFR Part 60, Subpart QQQ. (M-17; CD ¶29) (M-20)(M-22)(M24-R1)(M-25)

Navajo Refining shall comply with Subpart QQQ, including but not limited to:

1. In accordance with 60.692-2, each affected drain shall be equipped with water seal controls, shall be checked monthly for low water level, and shall have water added to drains as needed. Each affected junction box shall be equipped with a tightly sealed cover, shall be inspected semiannually, and shall have broken seals or covers repaired within 15 days. Each affected sewer line shall not be open to the atmosphere or contain cracks, shall be inspected semiannually, and shall have all cracks repaired within 15 days. Any other applicable requirements of 60.692-2 shall be observed;

2. In accordance with 60.692-3 (a), each affected oil-water separator tank (such as the API Oil/Water Separator associated with the Alkylation Unit) (11.1.b.4), slop oil tank, storage vessel, or other auxiliary equipment shall be equipped with a fixed roof that tightly and completely covers the affected unit; shall not have its vent space purged except to a control device; shall have all access doors tightly closed; shall have all seals, doors, and other openings checked for integrity; shall have all broken seals or gaskets repaired within 15 days; and shall comply with all other applicable requirements of 60.692-3;
3. In accordance with 60.692-3 (e), slop oil from an affected oil water separator tank and oily wastewater from affected slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in a closed system. Equipment used in handling such slop

oil shall be equipped with an appropriate fixed roof;

4. In accordance with 60.692-5, enclosed combustion devices and vapor recovery systems used as control devices shall have the efficiency required by 60.692-5 (a) or (b). Flares shall meet the requirements of 60.18. Closed vent systems shall be operated with no detectable emissions;

5. In accordance with 60.692-6, repair of affected equipment shall be carried out before the end of the next refinery or process unit shutdown. Delay of repairs is only allowed if repair is technically impossible without a complete or partial refinery or process unit shutdown;

6. In accordance with 60.696, before any equipment is installed to comply with this subpart, the equipment shall be inspected for indications of potential emissions, defects, or other problems. Closed vent systems shall be tested for no-detectable-emissions using Method 21 of NSPS Appendix A. All other applicable requirements of 60.696 shall be observed;

7. In accordance with 60.697, records shall be kept for affected drain systems including the location, date, and corrective action when the water seal is dry or otherwise breached or other problem identified that could result in VOC emissions. For affected junction boxes, records shall be kept of the location, date, and corrective action when a broken seal, gap, or other problem is identified that could result in VOC emissions. For affected sewer lines and oil-water separators, records shall be kept of the location, date, and corrective action for required inspections when a problem is discovered that could result in VOC emissions. For completely closed systems, records shall be kept of the location, date, and corrective action for required inspections during which detectable emissions are discovered that could result in VOC emissions; (14.4)

8. In accordance with 60.697, records shall be kept of the expected date of repair, the actual date of repair, and the reasons for delay of repair for VOC emission points in affected units. Records shall be kept of the design specifications of all equipment used to comply with this Subpart. Records shall be kept which demonstrate the efficiency of equipment used in closed systems and the operating parameters to be monitored and periods when the controls are not properly operating. Any other applicable provisions of 60.697 shall be observed;

9. In accordance with 60.698, initial reports shall be submitted showing that the appropriate equipment has been installed to comply with this Subpart and that the required initial inspection has been adequately completed. Semiannual reports as applicable shall be submitted showing that required inspections have been carried out. A semiannual summary shall be submitted identifying dry or breached seals, missing or improperly installed drain caps, or the presence of cracks, gaps, or other problems that could result in VOC emissions, including information on repairs or other corrective action; plus failures of any affected VOC

control system; and with regard to delay of leak repair, the date of the next process unit shutdown and the reasons why compliance with the standards is technically impossible without a process unit shutdown. (14.5.a)

6. 20.2.78 NMAC - Federal National Emission Standards for Hazardous Air Pollutants (NESHAP)

A. 40 CFR 61 Subpart A, "NESHAP General Provisions,"
Navajo Refining shall comply with all applicable requirements of Subpart A.

B. 40 CFR 61 Subpart V "National Emission Standard for Equipment Leaks (Fugitive Emission Sources)"
The Department has identified the facility as being potentially subject to the federal NESHAP, 40 CFR Part 61, Subpart V. Navajo Refining shall comply with Subpart V, as applicable, including but not limited to

1. Applicable standards in sections 61.242-1 through 61.244.
2. Applicable monitoring in section 61.242-1 through 61.244.
3. Applicable testing in section 61.245.
4. Applicable recordkeeping in section 61.246.
5. Applicable reporting in section 61.247.

C. 40 CFR 61 Subpart FF "National Emission Standard for Benzene Waste Operations"
The Department has identified the facility as being subject to the federal NESHAP, 40 CFR Part 61, Subpart FF. Navajo Refining shall comply with Subpart FF, as applicable, including but not limited to:

1) Standards as required by sections 61.342 through 61.352.
2) Monitoring as required by section 61.354.
3) Testing as required by section 61.355.
4) Recordkeeping as required by 61.356.
5) Reporting as required by section 61.357.

7. 20.2.82 NMAC – Maximum Achievable Control Technology Standards for Source Categories of Hazardous Air Pollutants (MACT)

The Department has identified the following process units as being subject to the federal MACT, 40 CFR Part 63. The Department believes this list to be accurate and complete. However, failure of this permit to list all sources subject to federal MACT does not relieve Navajo Refining from complying with any and all terms of the federal MACT. Where the MACT allows alternate methods of emission control, recordkeeping, or reporting, these methods may be implemented in accordance with the

MACT provisions.

A. MACT Subpart A, "General Provisions," 40 CFR 63.1
Navajo Refining shall comply with all applicable requirements of Subpart A.

B. MACT Subpart R, "National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations"

Permit Number	Affected Unit
195-M-25	Loading Spot TL-4

C. MACT Subpart CC, "National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries"

Navajo Refining shall comply with Subpart CC, as applicable, including but not limited to:

1. Standards and Provisions as required by sections 63.642 through 63.644 and 63.646 through 63.652, with the additional enhancements described in Condition 5.I.7 being applied to 63.648. (M-17)
2. Monitoring, recordkeeping and implementation plan for emission averaging as required by section 63.653.
3. Testing as required by section 63.645.
4. Recordkeeping and reporting as required by section 63.654.

D. MACT Subpart UUU, "National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units"

Navajo Refining shall comply with Subpart UUU, as applicable, for the following units:

- FCCU
- CCR
- SRUs 1,2, and 3

E. MACT Subpart DDDDD, " National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters", 40 CFR 63.7480 through 63.7575, or the site-specific version equivalent to MACT Subpart DDDDD proposed by Navajo as part of the M25 application.

Navajo Refining Company shall comply with the applicable portions of Subpart DDDDD, as promulgated on 09/13/2004 and amended 12/06/2006, for new or reconstructed large gaseous fuel category heaters, including but not limited to the 400 ppmvd CO limit, corrected to 3% O_2. Compliance will be demonstrated as follows:

1. Subject heaters greater than 10 MM Btu/hr but less than 100 MM Btu/hr (e.g., H-19, H-362, H-363, H-364 H-2421, HCKR-BOIL1 and HCKR-BOIL2) shall demonstrate compliance with the CO emissions limit using a 3-run average from an annual performance test. (M-20) (M-21) (M-25)
2. Subject heaters greater than 100 MMBtu/hr (e.g., Heater H-H2, ROSE2-HOH and H-H2-2) shall install a CO CEMS to demonstrate compliance on a 30-day rolling average basis. (M-22) (M-25)

8. Applicable Regulations, New Mexico Administrative Code, Title 20, Chapter 2 (20 NMAC Chapter 2)

The Department has identified the following as subject to the requirements of 20 NMAC, Chapter 2. The Department believes this list to be accurate and complete at the time of permit issuance. However, failure of this permit to list all sources subject to the NMAC does not relieve Navajo Refining from complying with any and all terms of the NMAC.

A. 20.2.7 NMAC (Excess Emissions During Malfunction, Startup, Shutdown, or Scheduled Maintenance, 11/30/95) applies to the refinery. (12.5.c, 13.5.b, 14.5.b)

B. 20.2.33 NMAC (Gas Burning Equipment – Nitrogen Dioxide, 10/31/02) applies to existing and new gas burning equipment having a heat input of greater than 1,000,000 million British Thermal Units per year (M-22). It applies to process heaters H-H2, H-H2-2, and ROSE2-HOH, and boilers B-7 and B-8. These units shall be equipped with ultra low-NOx emitting burners emitting less than 0.2 lb NOx per MM Btu.

C. 20.2.36 NMAC (Petroleum Refinery - Sulfur, 11/30/95) applies to the refinery as a whole. The sulfur recovery requirements of 20.2.36 NMAC shall be interpreted as stated in Condition 2.Gof this permit. Quarterly refinery-wide sulfur balance reports shall be filed in accordance with 20.2.36.113 NMAC. All flares and stacks shall meet the applicable height requirements of 20.2.36.114 NMAC. Any other applicable requirements of 20.2.36 NMAC shall be observed. (11.5.a.4)

D. 20.2.37 NMAC (Petroleum Processing Facilities, 11/30/95) applies as follows:

1. Section 200.A (Mercaptans) and section 200.B (Hydrogen Sulfide) apply to mercaptan and H_2S emissions from the refinery. Section 200.C applies to FL-400, FL-401, FL-402, FL-403, FL-404, and FL-405, and requires an alarm in good working order to signal non-combustion of the gas. (11.1.e) (M-17)

2. Section 201.A (CO), applies to the refinery's FCCU regenerator stack.

3. Section 202.B (PM), applies to the refinery's FCCU regenerator stack.

4. Section 203 (Ammonia, undiluted emissions = 25 ppmv), applies to all emission points of the refinery. (M-17)

5. Section 204 (Hydrocarbon Separation Facility), applies to all oil/water separators at the refinery. [Applicability to be resolved at a later date.]

6. Section 205 (Facilities - Storage - Handling - Pumping - Blowdown System) applies to certain of the following: storage tanks for organic compounds, loading and unloading of organic compounds, seals on pumps and compressors, and disposal (flaring) of hydrocarbon gases.

E. 20.2.38 NMAC (Hydrocarbon Storage Facilities, 11/30/95) applies to the refinery as follows:

1. Section 109 (Tank Storage Associated with Petroleum Production or Processing Facility [Sour Hydrocarbon Liquids]) applies to the loading of hydrocarbons containing H_2S.

2. Section 110 (Tank Battery or Storage Facility - Within Municipality [Sour Hydrocarbon Liquids]) applies to certain tanks storing sour hydrocarbon liquids whose vapors contain $\geq$24 ppm H_2S.
3. Section 113 (New Tank Battery and the Pecos-Permian Interstate Air Quality Control Region [Sour Hydrocarbon Liquids]) applies to certain tanks storing sour hydrocarbon liquids whose vapors contain $\geq$24 ppm H_2S.

F. 20.2.60 NMAC (Open Burning, 11/30/95) applies to all refinery areas. Fire training exercises shall require advance notification to the NMED.

9. Compliance tests and Certification Tests

A. Compliance tests.

Initial compliance tests, unless satisfactorily completed, are required for the following units:

Permit Number	Unit to be tested
195-M2	Combined heaters 70-H1/2/3 (redesignated as H-352, H-353, H-354), heater 70-H4 (redesignated as H-355), H-18, and H-40 for NO_x, CO, and SO_2. (14.7)
195-M3	Heater 3F-1 (H-600) for NO_x, CO, and SO_2. (13.7)
195-M4	Heater H-460 and tail gas incinerator H-463 for NOx, CO, and SO_2. (12.7)
195-M5-Rev.	Heater H-21 (formerly H-421) for NO_x, CO, and SO_2. (11.7) Floating roof tank T-450 for VOC was required to be tested but the

	tank was never constructed and hence testing was not done. It will be required to be tested under permit 195-M-7 (11.7)
195-M6	Heater H-9 and expanded heater H-18 for NO_x, CO, and SO_2. (4.i).
195-M7	Tank No. T-450 for VOCs in accordance with CFR Title 40, Part 60, Subpart Kb, Section 60.113b.
	Demonstrate the system setup and flow meters used to provide fuel gas as required under Condition 2.K.3.
	KES/SOLSEP in accordance with CFR Title 40, Part 60, Subpart QQQ, Section 60.696. [Removed in 195-M-7]
	Tail gas incinerator H-463 for SO_2.
	Conduct all applicable tests in accordance with CFR Title 40, Part 60, Subpart J, Section 60.106 and Section 60.108. 195-M-9.
	Boiler B-6 for NO_x, CO and SO_2
195-M12	Tail gas incinerator, Unit H-473, for SO_2
195-M14	Boiler B-7 for NO_x, CO, and SO_2 Boiler B-8 for NO_x, CO, and SO_2 Heater H-30 for NO_x, CO, and SO_2
195-M15	FCCU for NO_x, CO, SO_2, and PM Heater H-601 for NO_x, CO, and SO_2 Heater H-11 for NO_x, CO, and SO_2 **[Cancelled]** Heater H-20 for NO_x, CO, and SO_2 **[Cancelled]** Heater H-9 for NO_x, CO, and SO_2 Heater H-21 for NO_x, CO, and SO_2
195-M17	Heater H-SDA, for NO_x, CO, and SO_2
195-M20	Heater H-362, for NO_x, CO, and SO_2 (annually NOx and CO only) Heater H-363 for NO_x, CO, and SO_2 (annually NOx and CO only) Heater H-364 for NO_x, CO, and SO_2 (annually NOx and CO only) Heater H-2421 for NO_x, CO, and SO_2 (annually NOx and CO only)
195-M21	Heater H-19, for NO_x, CO, and SO_2 (annually NOx and CO only) Heater H-20 for NO_x, CO, and SO_2 (annually NOx and CO only)
195-M22	Heater H-H2, for NO_x, CO, and SO_2
195-M25	Heater ROSE2-HOH for NOx and CO
	Heater HCKR-BOIL1 for NOx and CO (annually NOx and CO)
	Heater HCKR-BOIL2 for NOx and CO (annually NOx and CO)
	Heater H-H2-2 for NOx and CO
	SRU3 Tail Gas Incinerator SRU3-TGI for SO_2

195-M25-R2	Heater H-600 for NO_X

Compliance tests may be re-imposed if Department inspections indicate possible noncompliance with permit Conditions subject to such testing, or noncompliance during the initial performance or subsequent tests, or if the tests were technically unsatisfactory. (4)

The test for any single unit shall be conducted within sixty (60) days after that unit achieves the maximum production rate at which the unit will normally be operated. If the maximum production rate does not occur within one hundred twenty (120) days of unit startup, then the test for each unit shall be conducted no later than one hundred eighty (180) days after initial startup of the unit. (4)

B. Monitor Certification Tests.

In addition to the H_2S monitor certification required by NSPS Subpart J, initial certification tests are required for the following units:

Permit Number	Unit to be Certified
195-M-2	The H_2S CEMS for refinery fuel gas serving heaters 70/H1/2/3, 70-H4, H-40 and H-18.
195-M-4	The SO_2 CEMS on the SRU incinerator stack.
195-M-7	Recertification of the SO_2 CEM on the SRU incinerator stack reflecting the NSPS Subpart J span of 500 ppmv.
195-M-12	The SO_2 CEM on Unit H-473, the SRU2/TGU2 incinerator stack, shall be certified initially and re-certified periodically, reflecting the NSPS subpart J span of 500 ppmv.
195-M-17	The CEMS on the FCCU Catalyst Regenerator stack and the NOx/O_2 CEMs applicable to Boilers B-7 and B-8 shall be certified initially for conformance with NSPS Subpart 60, Appendix B, Performance Specifications and then re-certified periodically.
195-M-22	The CO CEMS on the Heater H-H2 stack shall be certified initially for conformance with MACT Subpart DDDDD, which incorporates 40 CFR Part 60, Appendix B, Performance Specification 4A, and then re-certified as specified by MACT (M-22).
195-M-25	The CO CEMS on Heaters ROSE2-HOH and H-H2-2 stacks shall be certified initially for conformance with MACT Subpart DDDDD, and then re-certified as specified by MACT (M-25).
195-M-25	The NOx CEMS on Heaters ROSE2-HOH and H-H2-2 stacks shall be certified initially and then re-certified annually (M-25).
195-M-25	The SO_2 CEMS on the SRU3-TGI stack shall be certified initially for conformance with NSPS Subpart J, and then re-certified as specified by

NSPS (M-25).

All CEMS certifications and re-certifications shall be conducted in accordance with the applicable portions of 40 CFR Appendix A Reference Methods and Appendix B Performance Standards.

C Pretest Requirements and Test Report Requirements

1. The owner or operator shall notify the Department at least thirty (30) days prior to the test date to allow a representative of the Department to be present at the test. The notification shall be made by the submittal of a written test protocol for review by the NMED. The protocol shall describe the test methods to be used (including sampling methods and calibration procedures), shall list the equipment or devices to be tested (including sample locations), and shall describe data reduction procedures. Any variation from established sampling and analytical procedures or from facility operating Conditions shall be presented for NMED approval; (4.a) (M-25)

2. The test protocol and compliance test report shall conform to the standard format specified by the Department. The most current version of the format may be obtained from the Enforcement Section of the Air Quality Bureau. (4.b)

3. The permittee shall provide:
   a. sampling ports adequate for the test methods applicable to the facility,
   b. safe sampling platforms,
   c. safe access to sampling platforms and
   d. utilities for sampling and testing equipment.

   Sample ports of a size compatible with the test methods shall be located on the stacks of units to be tested in accordance with the provisions of EPA Method 1 of CFR, Title 40, Part 60, Appendix A. The stack shall be of sufficient height and diameter so that a representative test of the emissions can be performed in accordance with EPA Method 1. (4.c)

4. For stacks that have no ladders, thereby preventing access to the sampling port, the permittee shall also provide a one-quarter (1/4) inch stainless steel sampling line adjacent to the sampling ports and extending down to within four (4) feet above ground level to provide access for future audits. The line shall extend into the stack a distance of 1/4 the stack diameter, but not less than one inch from the stack wall. The sampling line shall be maintained clear of blockage at all times. This line shall be in place at the time of any required compliance tests. For any source for which compliance tests are not required or for previously existing sources this line shall be installed no later than one hundred and eighty (180) days from the date of Permit No. 195-M-6: March 13, 1996. (4.d)

5. Where necessary to prevent cyclonic flow in the stack, flow straighteners shall be installed. (4.f)

6. A copy of the compliance test report shall be submitted to the NMED Enforcement Section within thirty (30) days after completion of testing. (4.h)

D Compliance test Methods

1. **[CANCELLED**] VOC and benzene emissions from the groundwater stripper may be determined from water flow and concentration measurements. (5.d)

2. Heater and boiler tests shall be conducted in accordance with EPA Reference Methods 1 through 4, Method 7 (A-E) for oxides of nitrogen (NOx), Method 10 for carbon monoxide, and Method 6 or 6C for sulfur dioxide contained in CFR Title 40, Part 60, Appendix A, and with the requirements of Subpart A, General Provisions, 60.8(f). The results of the NOx tests shall be expressed as nitrogen dioxide (NO_2) using a molecular weight of 46 lb/lb mole in all calculations (each ppm of NO/NO_2 is equivalent to 1.194×10^{-7} lb/SCF). (4) (11.7)

3. During compliance tests, the following operational parameters shall be monitored and recorded for each heater or boiler:

   a. The heating value of the fuel (BTU/SCF) and the sulfur content of the fuel (grains/SCF). One determination shall be made within an hour of the first of the three test runs. A second determination shall be made within an hour of the completion of the third test run. If more than three hours delay occurs between the end of one test run and the start of another test run, a determination of the heating value shall also be made within an hour of the start of the next test run. (4.e.i)

   b. A continuous measurement of the fuel flow rate (SCF) to each heater during each test run and the total fuel used by each heater during each test run. (4.e.ii)

   c. The firebox temperature of each heater recorded at the beginning and at the end of each test run. (4.e.iii)

   d. For boilers, the steam generation rate (lb/hr).

   The information required by this Condition, including the calculated NOx emission factors for each heater (lb/MMBTU), shall be included with the test report that is required to be furnished to the Department and shall be listed in tabular form or as part of the summary page of the test report. (4.e)

4. Each test run shall be conducted at 90% of full capacity or greater, and at additional loads as specified by Department personnel at the time of the test or pre-test meeting. (4.g)

10. Recordkeeping

In addition to the applicable recordkeeping required by NSPS Subparts A, Db, J, K, Ka, Kb, GGG, QQQ, NESHAP Subpart(s) A, V and FF, MACT Subpart(s) A, CC, UUU and DDDDD (M-22), and the applicable parts of 20.2 NMAC, the following records shall be made and shall be maintained at the refinery for a minimum of five (5) years from the time of recording. The records shall be made readily available to the Department or a Department inspector upon request. The Department shall handle any confidential information in accordance with the provisions of 20.2.1.115 NMAC.

A. The recordkeeping requirements of 40 CFR 60 Subpart GGG, as found in section 60.486, for the LDMAR program associated with VOC-service equipment within the battery limits of the relocated Alkylation Unit, the existing North Crude Fractionation Unit (M-3) (13.4); the CBG Project components (M-18), the Naphtha Light Oil project fugitive components (M-19), the existing naphtha unit (FUG-06-NHDU) naphtha splitter project (M24-R1), PTRP (M24-R4) and the refinery expansion fugitive equipment components (M25).

B. Records of the hourly flow and concentration data from the SRU's SO2 CEM and associated flowmeter; (M-4) (12.4.a)

C. Records of the H_2S concentration of the gas streams feeding the SRU1 and SRU2. The records shall include the volumetric flow rates and concentrations of H2S upstream of the two SRUs, the concentrations and mass flow rates of SO_2 in the combined incinerator stack of TGU1, the sulfur removal efficiency in SRU1/SRU2/TGU1 and the mass sulfur balance across SRU1/SRU2/TGU1 from these data. (M-12)

D. Records of the type and quantity of the refinery fuel gas used to fire Diesel HDS charge heater H-21; (M-5-Rev) (11.4.2)

E. Records of all periods of operation during which the flare pilot flame is absent in flare FL-403 and the steps taken to re-ignite the pilot; (M-5-Rev) (11.4.4)

F. Records of the daily feedstock throughput to the Diesel HDS unit in BBL/day; (M-5-Rev) (11.4.6)

G. Records of all calibration and maintenance performed for the instruments that measure sulfur flow and concentration into and out of the SRU; (M-5-Rev) (11.7)

H. Records of the daily charge rate (BBL) into the Powerformer/Penex unit when the unit is operated in the Powerformer mode and when the unit is operated in the Penex mode; (M-6) (5.a)

I. Records of the actual daily crude oil feed charge to the South Crude Unit for each day of the month; (M-6) (5.b) (M-24)

J. Records of the daily average fuel flow and the monthly average heating value of the fuel to each of heaters H-9 and H-18; (M-6) (5.c)

K. [CANCELLED] Records of the VOC and benzene emissions from the 70-gallon-per-minute groundwater stripper using the concentration and volume flow of the inlet and outlet water streams to the stripper as determined from Condition 4.I, Monitoring of Operations. (M-6) (5.d)

L. Records of repairs, maintenance, and calibration of the acid gas flowmeter for Flare FL-403. (M-6) (1.f.iii)

M. Records of repairs, maintenance, and calibration of the fuel gas flowmeter(s) to provide supplemental heat to flare FL-400 and flare FL-403 and records of the quantity of supplemental heat used during each flaring incident (M-7; M-17)

N. Records as required under CFR Title 40, Part 60, Subpart Kb, Section 60.115b for the 80,000 bbl swing tank.(M-7)

O. [CANCELLED in M13] Records as required under CFR Title 40, Part 60, Subpart QQQ, Section 60.697 for the KES/SOLSEP.

P. Records of required Drager Tube and Houston Atlas H_2S analyses of the CCR off-gas streams that enter the refinery fuel gas system downstream of the fuel gas CEMS.

Q. Records of the actual FCCU charge rate of the refinery for each day of the month. (M-15)

R. Records of measurements taken by the CEMs on the FCCU Catalyst Regenerator stack, Boiler B-7 stack, Boiler B-8 stack and B-105 (M-17; CD ¶16)

S. Records of the combined firing rate (MMBtu/hr from fuel rate or steam production) of boilers B-7, B-8, and B-105 during periods when all three boilers are operated. (M-17)

T. Additional Records required by the Consent Decree (not an exhaustive listing)

   a) A list of all Controlled Heaters and Boilers on which NO_x Control Technology (permit condition 1.OO) was installed; (M-17; CD ¶16.E.i)

   b) The type of NOx Control Technology (permit condition 1.OO) that was installed on each heater and boiler with a detailed description of the manufacturer name and model and the designed emission factors; (M-17; CD ¶16.E.ii)

   c) The results of all performance tests conducted on each heater and boiler to date; (M-17; CD ¶16.E.iii)

d) A list of all heaters and boilers scheduled to have NO_x Control Technology (permit condition 1.OO) installed during the next calendar year, the projected date of installation, and the type of NO_x Control Technology that will be installed on these units; and (M-17; CD ¶16.E.iv)

e) An identification of proposed and established permit limits applicable to each heater or boiler for which NO_x Control Technology (permit condition 1.OO) has been installed pursuant to this paragraph. (M-17; CD ¶16.E.v)

f) CEMS data for all heater and boilers equipped with CEMS. (M-17; CD ¶16.C)

g) A record of the date when Boiler B-105 is retrofitted with low NOx burners and the date B-105 resumes operation. (M-17)

h) Records demonstrating on an on-going basis that the permittee has not burned fuel oil in any combustion unit except as provided for by permit condition 2 GG. (M-17; CD ¶17.C)

i) Modifications to the FCCU's good air pollution control practice plan to minimize NOx emissions shall be summarized on an annual basis. (M-17; CD ¶11.G)

j) Records demonstrating ongoing compliance with the FCCU's NO_2, SO_2, PM_{10} and CO emission limits. (M-17; CD ¶11.F, CD ¶12.D & CD ¶14.C)

k) Records demonstrating ongoing compliance with the emission limit specified by 40 CFR 60.104(a)(1) for flaring devices (including FL-400, FL-402 & FL-403) combusting routinely-generated refinery fuel gases. (M-17)

l) Records of SO_2 emissions and the root cause analysis conducted and corrective action taken by the permittee for each acid gas flaring and tail gas incidents occurring at the refinery. The protocol for this report shall be as provided for in paragraphs 20 A,D & E of the Consent Decree. (M-17; CD ¶20.A)

m) Records of emissions and the root cause analysis conducted and corrective action taken by the permittee for each hydrocarbon flaring incident using the protocol outlined in paragraphs 20.A – 20.B of the Consent Decree. (M-17; CD ¶21.A)

11. <u>Reporting</u>

In addition to the applicable reports required by NSPS Subpart(s) A, Db, J, K, Ka, Kb, GGG, and QQQ, NESHAP A, V and FF MACT Subpart(s) A, CC, UUU and DDDDD and by the applicable parts of 20.2 NMAC, the following information shall be submitted to the Department. The reports shall be submitted to the Air Quality Bureau within forty five (45) days of the end of each calendar quarter. If any reports indicate potential non-compliance with the terms of this permit, the Bureau may impose a more frequent reporting time-frame. (12.5.a) The Department shall handle any confidential information in accordance with the provisions of 20.2.1.115 NMAC. (6)

A. Reports on a Daily Basis

For SRU1/SRU2 (/H-473) the **reports** shall contain for each day in the quarter:

1. a. The maximum hourly, combined, SO_2 emission rate (pound per hour) for each day of the quarter. (M-4) (12.5.a.11)

   b. For any hourly period when the SO_2 emission rate exceeds the combined limit of 30.0 pounds per hour, the emission rate, date and times during which the excess emission took place; (M-4, revised M-12, M-14-R1, M-15, and M-20) (12.5.a.11)

B. Reports on a Monthly Basis

The **report** shall contain for each month in the quarter:

1. The data capture percent for each SO_2 incinerator stack gas monitor, for the flowmeters for the SRU inlet streams, and for the flowmeter at each incinerator stack. (M-12)
2. The charge rate (in BBL) to the Powerformer/Penex unit when operated in the Powerformer mode and the charge rate (in BBL) when operated in the Penex mode; (M-6) (6.a)
3. For each calendar month, the calculated daily average crude oil feed charge to the South Crude Unit; (M-6) (6.b) (M-24)
4. The daily average fuel flow (SCF) and the monthly average heating value of the fuel to each of heaters H-9 and H-18; (M-6) (6.c)
5. **[CANCELLED]** The VOC and the benzene emission rate (pph) from the groundwater stripper determined from the test required by Condition 4.I, Monitoring of Operations; (M-6) (6.d)
6. The total amount of acid gas flared each month, expressed as short tons of SO2, obtained from the acid gas flowmeter(s) and H_2S concentration of the acid gas. (M-6) (6.e).

C. Reports on a Semiannual Basis

Although not required by NSPS Subpart GGG, this permit assigns the semiannual reporting requirements of 40 CFR 60 Subpart GGG, as found in Section 60.487, to the VOC Service equipment in the relocated Alkylation Unit, the North Crude Fractionation Unit, the CBG Project components, and the Naphtha Light Oil project fugitive components. Semiannual reporting of LDAR monitoring results for the Amine Unit is to be provided with the MACT periodic report. (13.5.a) (M-18) (M-19)

In each MACT periodic report required under 40 CFR §63.654, the following information shall be provided:

1. The results of tank inspections and seal gap measurements made during the semiannual

period. (M-17)

2. The following information on LDAR monitoring: (M-17)
   a. a list of process units monitored during the quarter;
   b. number of valves & pumps monitored in each process unit;
   c. the number of valves & pumps found leaking;
   d. the number of 'difficult to monitor' pieces of equipment monitored;
   e. the projected month of the next monitoring event for that unit; and
   f. a list of all equipment currently on the "delay of repair" list and the date each component was placed on the list.

D. Reports on an Annual Basis

An annual **summary report** shall be submitted to the Department on or before February 15 of each year which shows:

1. The total BTU fuel consumption by each of heaters H-9 and H-18 for each month of the preceding calendar year. (6.f)

E. Miscellaneous Reporting

In addition, the permittee shall **notify** the Enforcement Section, Air Quality Bureau in writing of:

1. The actual date of initial startup of each new or modified source within fifteen (15) days after the startup date; (6.h)
2. The date when each new or modified emission source reaches the maximum production rate at which it will operate within fifteen (15) days after that date; (6.i)
3. Any change of operators within fifteen (15) days of such change; (6.j)
4. Any necessary update or correction no more than sixty (60) days after the operator knows or should have known of the Condition necessitating the update or correction of the permit. (6.k)

F. Reporting required by the Consent Decree (not an exhaustive listing)

1 The permittee shall notify the Department's Enforcement Section, Air Quality Bureau in writing of:

   a. the annual progress of installation of NO_x Control Technology required by Paragraph 16 of the Consent Decree. This report shall contain all items specified in Condition 10.T (a-e) above. The report shall be submitted to the EPA and the NMED on or before December 31st of each calendar year commencing with the year 2002.

(M-17; CD ¶16.E)

2 Investigation and Reporting

a. No later than forty-five (45) days following the end of an AG Flaring or TG Incident, the permittee shall submit to EPA and the NMED a report that sets forth the items detailed as follows. (M-17; CD ¶20.A)

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

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

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

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

v) An analysis of the measures, if any, available to reduce the likelihood of a recurrence of the AG Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis shall discuss the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation and maintenance change shall be evaluated. If the permittee concludes that the corrective action(s) is (are) required under Paragraph 20.B of the Consent Decree, the report shall include a description of the action(s) taken and, if not already completed, a schedule for its (their) implementation, including proposed commencement and completion dates. If the permittee concludes that corrective action is not required under Paragraph 20.B of the Consent Decree, the report shall explain the basis for that conclusion.

vi) To the extent that the investigations of the causes and/or possible corrective actions are still underway on the due date of the report, a statement of the anticipated date by which a follow-up report fully conforming to the requirements of Paragraph 20.A.iv and 20.A.v of the Consent Decree shall be submitted.

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

viii) As specified in Paragraph 20.D.iii of the Consent Decree, the report required under Paragraph 20.A.i (permit condition 10.F.10 above) of the Consent Decree shall include the data used in the calculation of the SO_2 quantity and rate emitted during AG Flaring Incident and an explanation of the basis for any estimates of missing data points.

b. For the purposes of determining the quantity and rate of SO_2 emissions the permittee shall measure the flow of gas to the AG Flaring Devices and determine the Hydrogen Sulfide concentration from the SRP feed gas analyzer by direct measurement, by Tutweiler, or Draeger tube analysis, or by any other method approved by EPA or the NMED. Calculations of SO_2 emitted during AG Flaring Incidents shall be performed in accordance with the procedures in Paragraphs 20.D.i through 20.D.iii of the Consent Decree. (M-17; CD ¶20.D)

c. Calculations of SO_2 emitted during TG Incidents shall be performed in accordance with the procedures in Paragraph 20.E.ii of the Consent Decree. (M-17; CD ¶20.E)

d. For hydrocarbon flaring incidents, the permittee shall follow the same investigative, reporting, and corrective action procedures as those outlined in paragraphs 20.A – 20.B of the Consent Decree for acid gas flaring incidents. The formulas and equations at Paragraph 20.D of the Consent Decree, used for calculating the quantity and rate of sulfur dioxide emissions during AG Flaring Incidents, shall be used to calculate the quantity and rate of sulfur dioxide emissions during HC Flaring Incidents. (M-17; CD ¶21)

e) If EPA does not notify the permittee in writing within thirty (30) days of receipt of the report(s) required by Paragraph 20.A of the Consent Decree that it objects to one or more aspects of the proposed corrective action(s), if any, and schedules(s) of implementation, if any, then that (those) action(s) and schedules(s) shall be deemed acceptable for purposes of compliance with Paragraph 20.B.i of the Consent Decree. Notwithstanding EPA's review of any plans, reports, corrective measures or procedures under this Paragraph 20 of the Consent Decree, the permittee shall be solely responsible for non-compliance with the Clean Air Act and its implementing regulations. (M-17; CD ¶20.B)

3 As specified in Section VIII, Paragraph 29.A, Plan to Comply with NSPS Subpart QQQ of the Consent Decree, by no later than 180 days after the Date of Lodging of the Consent Decree, the permittee shall submit a plan to EPA and NMED that sets forth with specificity the actions, including but not limited to, the installation of any necessary control equipment, the permittee will take to ensure that the Refinery complies, by no later than December 31, 2003, with the requirements of the NSPS at Subpart QQQ, 40 CFR §§60.690-60.699. The

plan shall include a proposed schedule of implementation for the installation of any necessary control equipment, and proposed schedules for compliance with the monitoring, testing, recordkeeping and reporting requirements of 40 CFR §§60.695-60.698. The plan shall be subject to the approval, disapproval, or modification(s) by EPA, which shall act in consultation with NMED. Within sixty (60) days after receiving any notification of disapproval or request for modification from EPA, the permittee shall submit to EPA and NMED a revised plan that responds to all identified deficiencies. Upon receipt of final approval or approval with conditions, the permittee shall implement the plan. (M-17; CD ¶29)

4 By no later than February 28, 2004, develop and submit to EPA and the NMED a plan to study how to limit AG Flaring and emissions in excess of 250 ppmvd of SO_2 (measured at 0% Oxygen) from the TGU during the limited periods in which the Artesia SRP experiences a Malfunction. The study plan shall include an implementation schedule to be implemented by the permittee. The permittee shall incorporate the results of this study into the PMO Plan prepared pursuant to Paragraph 20.D of the Consent Decree. (M-17; CD ¶30)

12. Revisions and Modifications (7)

A. Any future physical changes or changes in the method of operation may constitute a modification as defined by 20.2.72 NMAC, Construction Permits, (AQCR 702) and shall be preceded by the submittal of a permit application for review by the Department.

B. Changes in process equipment (including replacement) which emit or affect emissions and changes in process streams that eliminate bottlenecks may be a modification under 20.2.72 NMAC or 20.2.74 NMAC. No modification shall begin prior to issuance of a permit.

C. The construction or installation of any emissions unit not authorized under this permit, or any physical change in or change in the method of operation which results in an increase in the potential emission rate of any regulated air contaminant, would constitute a modification under 20.2.72 NMAC. Regulation 20.2.72 NMAC does not provide for and does not contain provisions for netting of emissions in order to avoid the construction permitting process.

D. Unless modified by conditions of this permit, the applicant shall construct or modify and operate the facility in accordance with all representations of the application and supplemental submittals that the Department relied upon to determine compliance with applicable regulations and ambient air quality standards. If the Department relied on air quality modeling to issue this permit, any change in the parameters used for this modeling shall be submitted to the Department for review. Upon the Department's request, the applicant shall submit additional modeling for review by the Department. Results of that review may require a permit modification. (20.2.72 NMAC, Section 210.A).

E. Changes in plans, specifications, and other representations stated in the application documents shall not be made if they cause a change in the method of control of emissions or in the character of emissions, or will increase the discharge of emissions. Any such proposed changes shall be submitted as a revision or modification.

13. Notification to Subsequent Owners (8)

The permit and Conditions apply in the event of any change in control or ownership of the facility. No permit modification is required in such case. However, in the event of any such change in control or ownership, the permittee shall notify the succeeding owner of the permit and Conditions and shall notify the Department of the change in ownership within fifteen (15) days of that change.

14. Right to Access Property and Review Records (9)

The Department and EPA shall be given the right to enter the facility at all reasonable times to verify the terms and Conditions of this permit. The company, upon either a verbal or written request from an authorized representative of the Department, shall produce any records or information necessary to establish that the terms and Conditions of this permit are being met.

15. Posting of the Permit (10)

A copy of this permit shall be posted and in view at Navajo Refining's main office building at all times and shall be made available to Department personnel for inspection upon request.

16. Permit Cancellations

20.2.72.11 NMAC Permit Cancellations, 2.74 Sections 300.C and 302.G requires that:

1. The Department shall automatically cancel any permit for any source which ceases operation for five (5) years or more, or permanently. Reactivation of any source after the five (5) year period shall require a new permit.

2. The Department may cancel a permit if the construction or modification is not commenced within two (2) years from the date of issuance or if, during the construction or modification, work is suspended for a total of one (1) year.

3. Approval to construct the sources authorized by PSD-NM-0195-M25 shall become invalid if: 1) construction is not commenced within eighteen (18) months after receipt of approval; 2) if construction is discontinued for a period of eighteen (18) months or more; or

3) if construction is not completed within a reasonable time. The secretary may extend the eighteen (18) month period upon a satisfactory showing that an extension is justified. (M-25)

4. If the permittee, applies for an extension, and the new proposed date of construction is greater than eighteen (18) months from the date the permit would become invalid, the determination of Best Available Control Technology shall be reviewed and modified as appropriate before such extension is granted. At such time, the permittee shall demonstrate the adequacy of any previous determination of Best Available Control Technology for the affected source(s). (M-25)

ADDITIONAL REQUIREMENTS

20.2.73 NMAC contains requirements related to Notice of Intent and Emission Inventory. Please refer to that regulation for details. (M-24)

Applications for permit revisions and modifications shall be submitted to:

Program Manager, Permits Section
New Mexico Environment Department
Air Quality Bureau
1301 Siler Rd., Building B
Santa Fe, New Mexico 87507

Compliance test protocols, test notifications, the second copy of test results, and excess emission reports, shall be submitted to:

Program Manager, Enforcement Section
New Mexico Environment Department
Air Quality Bureau
1301 Siler Rd., Building B
Santa Fe, New Mexico 87507

Regularly scheduled reports (annual, semiannual, quarterly, or monthly) shall be submitted to:

Program Manager, Compliance Section
New Mexico Environment Department
Air Quality Bureau
1301 Siler Rd., Building B
Santa Fe, New Mexico 87507

REVOCATION

The Department may revoke this permit if the applicant or permittee has knowingly and willfully misrepresented a material fact in the application for the permit. The Department will make revocations in writing. The Secretary of the Department will accept administrative appeals within thirty (30) days from the effective date of this permit in accordance with the Department's Rules Governing Appeals From Compliance Orders.

APPEAL PROCEDURES

20.2.72.207 NMAC, provides that any person who participated in a permitting action before the Department and who is adversely affected by such permitting action, may file a petition for hearing before the Environmental Improvement Board. The petition shall be made in writing to the Environmental Improvement Board within thirty (30) days from the date notice is given of the Department's action and shall specify the portions of the permitting action to which the petitioner objects, certify that a copy of the petition has been mailed or hand-delivered and attach a copy of the permitting action for which review is sought. Unless a timely request for hearing is made, the decision of the Department shall be final. The petition shall be copied simultaneously to the Department upon receipt of the appeal notice. If the petitioner is not the applicant or permittee, the petitioner shall mail or hand-deliver a copy of the petition to the applicant or permittee. The Department shall certify the administrative record to the board. Petitions for a hearing shall be sent to:

Environmental Improvement Board
1190 St. Francis Drive, Runnels Bldg.
P.O. Box 26110
Santa Fe, New Mexico 87502

If you have questions about this permit please call Kerwin Singleton of the New Source Review Section in Santa Fe at (505) 476-4350.

Enclosure: Industry/Consultant Feedback Questionnaire with envelope

Table 1 Allowable Emission Limits

			SO_2		NOx			CO		PM		VOC	
	Source ID	**MM Btu/hr**	**(lb/hr)**	**(ton/yr)**	**(lb/hr)**	**(ton/yr)**	**(lb/MM Btu)**	**(lb/hr)**	**(ton/yr)**	**(lb/hr)**	**(ton/yr)**	**(lb/hr)**	**(ton/yr)**
b, r, u, aa, cc	B-7	215	8.2	13.5	12.9	56.5	0.06	19.6	85.7	1.8	7.8	1.3	5.6
b, r, u, aa, cc	B-8	215	8.2	13.5	12.9	56.5	0.06	19.6	85.7	1.8	7.8	1.3	5.6
j, s, aa, cc	H-9	44	1.7	2.8	4.0	17.3	0.09	4.0	17.5	0.4	1.6	0.3	1.2
a, aa, cc	H-11	38	1.5	2.4	9.5	31.6	-	3.5	15.2	0.3	1.4	0.2	1.0
j, s, aa, cc	H-18	32	1.2	2.0	3.5	15.2	-	2.9	12.8	0.3	1.2	0.2	0.8
w, aa, cc	H-19	54	2.1	3.4	2.9	12.5	0.0527	4.9	21.5	0.4	2.0	0.3	1.4
b, w, ~~z~~, aa, cc	H-20	78	3.0	4.9	4.2	18.3	0.0535	7.1	31.1	0.6	2.8	0.5	2.0
l, s, aa, cc	H-28	9.3	0.4	0.6	1.4	7.2	-	0.9	3.7	0.1	0.3	0.1	0.2
m, r, aa, cc	H-30	42	1.6	2.6	3.2	14.0	-	3.8	16.8	0.4	1.5	0.3	1.1
d, aa, cc	H-40	42	1.6	2.6	3.8	16.6	-	3.8	16.8	0.4	1.5	0.3	1.1
d, aa, cc	H-352/353/354	63/81/56	7.6	12.5	9.1	39.4	0.045	18.2	79.7	1.7	7.2	1.2	5.2
d, aa, cc	H-355	24	0.9	1.5	216	9.5	-	2.2	9.5	0.2	0.9	0.1	0.6
a, aa, cc	H-303	11	0.4	0.7	1.2	5.2	-	1.0	4.4	0.1	0.4	0.1	0.3
a, aa, cc	H-312	35	1.3	2.2	4.6	20.2	-	3.2	13.9	0.3	1.3	0.2	0.9
v, aa, cc	H-362/363/364	40/50/35	4.8	7.8	6.9	30.1	0.055	11.4	49.7	1.0	4.5	0.7	3.3
g, s, aa, cc	H-421	27	1.0	1.7	2.4	10.6	0.09	2.5	10.8	0.2	1.0	0.2	0.7
f, aa, cc	H-460	5	0.2	0.3	0.8	3.3	-	0.5	2.0	<0.1	0.2	<0.1	0.1
t, aa, cc	H-464	9.6	0.4	0.6	0.5	2.3	-	0.9	3.8	0.1	0.4	0.1	0.3
e, aa, cc	H-600	84	3.2	5.3	4.6	20.3	0.05	7.6	33.5	0.7	3.03	0.5	2.2
s, aa, cc	H-601	78	3.0	4.9	3.5	15.4	0.045	7.1	31.1	0.6	2.8	0.5	2.0
v, aa, cc	H-2421	27	1.0	1.7	1.2	5.3	0.045	2.5	10.8	0.2	1.0	0.2	0.7
x, aa, cc	H-8801/8802	60/60	0.2	0.8	4.2	18.4	0.035	10.9	47.8	1.0	4.3	0.7	3.1
u, aa, cc	H-31	28	1.1	1.8	1.6	6.8	-	2.6	11.2	0.2	1.0	0.2	0.7
aa, cc	(ROSE2-HOH)	120	4.6	7.5	3.6	15.8	0.03	7.2	31.5	1.0	4.3	0.7	3.1
aa, cc	(HCKR-FRN1)	9.6	0.4	0.6	0.3	1.3	0.03	0.9	3.8	0.1	0.4	0.1	0.3
aa, cc	(HCKR-FRN2)	9.6	0.4	0.6	0.3	1.3	0.03	0.9	3.8	0.1	0.4	0.1	0.3
aa, cc	(HCKR-BOIL1)	35	1.3	2.2	1.1	4.6	0.03	3.2	13.9	0.3	1.3	0.2	0.9
aa, cc	(HCKR-BOIL2)	35	1.3	2.2	1.1	4.6	0.03	3.2	13.9	0.3	1.3	0.2	0.9
aa, bb, cc	(H-H2-2)	337	0.5	2.2	4.2	18.5	0.0125	20.2	88.6	2.8	12.2	2.0	8.8
aa, cc	(SRU3-HOH)	9.6	0.4	0.6	0.3	1.3	0.03	0.9	3.8	0.1	0.4	0.1	0.3
f, n, p, q, s, v,	H-473 (TGI)	NA	30.0	81.8	6.5	28.5	N/A	27.7	121.2	0.5	2.2	0.1	0.6

			SO_2		NOx			CO		PM		VOC	
	Source ID	MM Btu/hr	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/MM Btu)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)
aa, cc													
aa, cc	(SRU3-TGI)	NA	30.0	81.8	6.5	28.5	N/A	15.0	65.7	0.5	2.2	0.1	0.6
c, s. v, aa, cc	FCC Regenerator	NA	27.9	61.0	35.0	101.9	N/A	121.9	106.8	25.0	109.5	-	-
i, aa, cc	FL-400	NA	0.19	0.5	0.2	0.8	N/A	1.0	4.3	0.0	0.0	0.2	0.7
i, aa, cc	FL-401	NA	0.1	0.1	<0.1	0.2	N/A	0.2	1.1	0.0	0.0	<0.1	0.2
i, aa, cc	FL-402	NA	0.1	0.1	<0.1	0.2	N/A	0.2	1.1	0.0	0.0	<0.1	0.2
i, aa, cc	FL-403	NA	2.3	10.2	3.6	15.8	N/A	13.5	59.0	0.0	0.0	2.3	10.0
s, aa, cc	FL-404	NA	0.1	0.3	0.5	2.4	N/A	0.2	0.8	0.0	0.0	<0.1	0.1
aa, cc	FL-405	NA	0.1	0.4	0.5	2.4	N/A	0.2	0.8	0.0	0.0	<0.1	0.1
	TOTAL	NA	153.9	342.1	167.7	673.1	N/A	357.0	1136.4	43.3	189.6	15.4	67.3

a Source in existence prior to, and unmodified since, August 31, 1972. Emission rates not affected by modification are taken as both the potential emission rate and the potential to emit of that unit.
b Permit 155
c Permit 236 (no permit required based on no increase in emissions over the TCCU it replaced)
d Permit 195-M-2
e Permit 195-M-3
f Permit 195-M-4
g Permit 195-M-5
h Single stack for combined furnaces H-301, H-302, &H-304
i 3 refinery flares @ 15Mcfd each, except during upset conditions; FL-400 may burn natural gas, Refinery fuel gas, produced hydrogen, or any combination thereof for pilot and purge, depending on operational needs; FL-401 & FL-402 may burn natural gas for pilot and purge.
j Permit 195-M-6
k Permit 80
l Heater H-10 was replaced by H-28. The replacement was the subject of the consent agreement between the Department and Navajo Refining executed January 31, 1994.
m No permit required (NPR), file no. 31
n Permit 195-M-7. Added tail gas cleanup unit. (NSPS Subpart J limits SO_2 to 250 ppmv on a dry basis and at 0% excess air)
o Permit 195-M-9. Replaced Boiler 3 with Boiler 6
p Permit 195-M-10. Increased capacity of SRU with tail gas incinerator to 40 long tons per day.
q Permit 195-M-12. Added a second SRU with tail gas incinerator with 100 long ton per day capacity.
r Permit 195-M-14. Replaced Boilers B-1, B-2, B-4, B-6, B-103, B-104, B-105 with Boilers B-7, B-8. Replaced Heater H-26 with Heater H-30.
s Permit 195-M-15. Returned H-11 and H-20 emission limits to prior rates. They were not affected by the permitted Project since South Plant expansion portion was cancelled. Consistent with Title V permit Scenario 2.
t Permit 195-M-15-R2. Added hot oil heater H-464 for the SRP.
u Permit 195-M-17. Added H-SDA. Capped combined B-7, B-8, & B-105 emission limit at PTE for B-7 + B-8
v Permit 195-M-20. Added ULSD Project sources H-362, H-363, H-364 and H-2421. Revised H-473 emission rates to reflect option to install oxygen enrichment process on SRU2. Lowered FCC Regenerator SO2 emission rates to match Consent Decree limits. Removed shutdown sources Heater H-15, X-591 (combined stack for Heaters H301/H302/H304), and Compressor C-301.
w Permit 195-M-21. Added South Crude Unit Efficiency Project Heater H-19, revised Heater H-20 NOx emission rates to reflect burner retrofit.
x Permit 195-M-22. Added Hydrogen Plant heater H-H2.
y Permit 195-M-22. Added Hydrogen Plant Deaerator Vent that includes Ammonia emission limit (Condition 3.J.)
~~z Permit 195-M24. Added condition 3.I.6: Emission limit of lb NOx/MM Btu over a 3-hour rolling average period, in addition to the existing mass emission limits.~~ {Deleted as applicable requirement is stated in permit conditions 3.I and J. – Permit 195-M25}

aa Permit PSD-NM-195-M25. Added Refinery Expansion sources ROSE2-HOH, HCKR-FRN1, HCKR-FRN2, HCKR-BOIL1, HCKR-BOIL2, H-H2-2, SRU3-HOH, SRU3-TGI and FL-405. The permit application revised all other emission sources emission rates to reflect consistent emission estimation methodology.

bb The Steam Reformer Furnace (H-H2-2) shall not emit greater than 1.38 lb/hr and 6.04 ton/yr of NH_3, and shall not emit more than 0.032 lbs/mmbtu of NOx during startup, shutdown or maintenance activities.

cc. Permit PSD-NM-195-M25-R2: Added VOC emission rates

TABLE 2A

VAPOR PRESSURE LIMITATIONS FOR REFINERY NON-COMBUSTION SOURCES OF VOLATILE ORGANIC COMPOUNDS (VOC)

INTERNAL FLOATING ROOF STORAGE TANKS

Tank No.	**Typical Liquid Stored**	**Most Volatile Category of Allowable Liquids to be Stored**[1]	**Max Vapor Pressure (psia) of Most Volatile Liquid at Max Temp.**
IFR Tanks			
T-56	Gas Oils	Low Vapor Pressure[4]	0.5
T-106	Distillates	High Vapor Pressure[2]	11.00
T-107~~S~~	Gasolines	High Vapor Pressure[2]	11.00
T-108	Gasolines	High Vapor Pressure[2]	11.00
T-109	Gasolines	High Vapor Pressure[2]	11.00
T-111	Naphthas	High Vapor Pressure[2]	11.00
T-112	Naphthas	High Vapor Pressure[2]	11.00
T-11~~S~~	Gasolines	High Vapor Pressure[2]	11.00
T-124	Gasolines	High Vapor Pressure[2]	11.00
T-12~~S~~	Gasolines	High Vapor Pressure[2]	11.00
T-413	Distillates	High Vapor Pressure[2]	11.00
T-415	Gasolines	High Vapor Pressure[2]	11.00
T-417	Gasolines	High Vapor Pressure[2]	11.00
T-439	Crude Oil	High Vapor Pressure[2]	11.00

1 Liquids in lower volatility categories may also be stored (i.e., tanks allowed to store high vapor pressure category liquids can also store moderate and low vapor pressure category liquids; tanks allowed to store moderate vapor pressure category liquids can also store low vapor pressure category liquids).

2 High Vapor Pressure Liquids include: Crude, Naphtha (raw or treated), Unleaded Gasolines (sub-grade, regular, premium, and other blends), Alkylate, Reformate, FCC Gasoline, Ethanol, Isomerate, Straight Run Gasoline, and other refinery feedstocks, intermediates, products, byproducts, and wastes having a max vapor pressure of 11 psia or less under actual storage conditions.

TABLE 2B

VAPOR PRESSURE LIMITATIONS FOR REFINERY NON-COMBUSTION SOURCES OF VOLATILE ORGANIC COMPOUNDS (VOC)

EXTERNAL FLOATING ROOF STORAGE TANKS

Tank No.	Typical Liquid Stored	Most Volatile Category of Allowable Liquids to be Stored[1]	Max Vapor Pressure (psia) of Most Volatile Liquid at Max Temp.
EFR Tanks			
T-0078	Isomerates	High Vapor Pressure[2]	11.00
T-0079	Isomerates	High Vapor Pressure[2]	11.00
T-117	Gasolines	High Vapor Pressure[2]	11.00
T-401	Gasolines	High Vapor Pressure[2]	11.00
T-402	Gasolines	High Vapor Pressure[2]	11.00
T-411	Gasolines	High Vapor Pressure[2]	11.00
T-412	Gasolines	High Vapor Pressure[2]	11.00
T-435	Crude Oil	High Vapor Pressure[2]	11.00
T-437	Crude Oil	High Vapor Pressure[2]	11.00
T-450	Naphthas	High Vapor Pressure[2]	11.00
T-57	Naphthas	High Vapor Pressure[2]	11.00
T-802	Sour Water	High Vapor Pressure[2]	11.00
T-834	Distillates	High Vapor Pressure[2]	11.00
T-835	Distillates	High Vapor Pressure[2]	11.00
T-1225 (formerly NAP-TK)	Naphthas	High Vapor Pressure[2]	11.00
T-0737 (formerly NEW-SOURTK)	Sour Water	High Vapor Pressure[2]	11.00

1 Liquids in lower volatility categories may also be stored (i.e., tanks allowed to store high vapor pressure category liquids can also store moderate and low vapor pressure category liquids; tanks allowed to store moderate vapor pressure category liquids can also store low vapor pressure category liquids).

2 High Vapor Pressure Liquids include: Crude, Naphtha (raw or treated), Unleaded Gasolines (sub-grade, regular, premium, and other blends), Alkylate, Reformate, FCC Gasoline, Ethanol, Isomerate, Straight Run Gasoline, and other refinery feedstocks, intermediates, products, byproducts, and wastes having a max vapor pressure of 11 psia or less under actual storage conditions.

TABLE 2C

VAPOR PRESSURE LIMITATIONS FOR REFINERY NON-COMBUSTION SOURCES OF VOLATILE ORGANIC COMPOUNDS {VOCs)

FIXED ROOF STORAGE TANKS

Tank No.	Typical Liquid Stored	Most Volatile Category of Allowable Liquids to be Stored[1]	Max Vapor Pressure (psia) of Most Volatile Liquid at Max Temp.
Fixed-Roof Tanks			
T-110	Asphalt/Pitch	Low Vapor Pressure[4]	0.5
T-13	Slop	Moderate Vapor Pressure[3]	1.50
~~T-18~~	~~Slop~~	~~Moderate Vapor Pressure~~[3]	~~1.50~~
T-40	Distillates	Low Vapor Pressure[4]	0.5
T-400	Gas Oils	Low Vapor Pressure[4]	0.5
T-404	Carbon Black Oil (CBO)	Low Vapor Pressure[4]	0.5
T-405	CBO	Low Vapor Pressure[4]	0.5
T-409	Gas Oils	Low Vapor Pressure[4]	0.5
T-41	Distillates	Low Vapor Pressure[4]	0.5
T-410	Asphalt/Pitch	Low Vapor Pressure[4]	0.5
T-418	Distillates	Low Vapor Pressure[4]	0.5
T-419	Distillates	Low Vapor Pressure[4]	0.5
T-420	CBO	Low Vapor Pressure[4]	0.5
T-422	Distillates	Low Vapor Pressure[4]	0.5
T-423	Distillates	Low Vapor Pressure[4]	0.5
T-431	Distillates	Low Vapor Pressure[4]	0.5
T-432	Distillates	Low Vapor Pressure[4]	0.5

TABLE 2C –cont'd

EMISSION LIMITATIONS FOR REFINERY NON-COMBUSTION SOURCES OF VOLATILE ORGANIC COMPOUNDS {VOCs)

FIXED ROOF STORAGE TANKS

Tank No.	Typical Liquid Stored	Most Volatile Category of Allowable Liquids to be Stored[1]	Max Vapor Pressure (psia) of Most Volatile Liquid at Max Temp.
T-433	Gas Oils	Low Vapor Pressure[4]	0.5
T-434	Distillates	Low Vapor Pressure[4]	0.5
T-438	Gas Oils	Low Vapor Pressure[4]	0.5
T-49	Slop	Moderate Vapor Pressure[3]	1.50
T-55	Distillates	Low Vapor Pressure[4]	0.5
T-58	Distillates	Low Vapor Pressure[4]	0.5
T-59	CBO	Low Vapor Pressure[4]	0.5
T-61	Distillates	Low Vapor Pressure[4]	0.5
T-63	CBO	Low Vapor Pressure[4]	0.5
T-65	CBO	Low Vapor Pressure[4]	0.5
T-75	CBO	Low Vapor Pressure[4]	0.5
T-810	Slop	Moderate Vapor Pressure[3]	1.5
T-814	Asphalt/Pitch	Low Vapor Pressure[4]	0.5
T-815	Distillates	Low Vapor Pressure[4]	0.5
T-838	Distillates	Low Vapor Pressure[4]	0.5
T-1227 (formerly PITCH-TK1)	Asphalt/Pitch	Low Vapor Pressure[4]	0.5
PITCH-TK2	Asphalt/Pitch	Low Vapor Pressure[4]	0.5
PITCH-TK3	Asphalt/Pitch	Low Vapor Pressure[4]	0.5
RW-4	Gasolines	High Vapor Pressure[2]	11.00

Tank No.	Typical Liquid Stored	Most Volatile Category of Allowable Liquids to be Stored[1]	Max Vapor Pressure (psia) of Most Volatile Liquid at Max Temp.
RW-5	Gasolines	High Vapor Pressure[2]	11.00
RW-6	Gasolines	High Vapor Pressure[2]	11.00

1 Liquids in lower volatility categories may also be stored (i.e., tanks allowed to store high vapor pressure category liquids can also store moderate and low vapor pressure category liquids; tanks allowed to store moderate vapor pressure category liquids can also store low vapor pressure category liquids).

2 High Vapor Pressure Liquids include: Crude, Naphtha (raw or treated), Unleaded Gasolines (sub-grade, regular, premium, and other blends), Alkylate, Reformate, FCC Gasoline, Ethanol, Isomerate, Straight Run Gasoline, and other refinery feedstocks, intermediates, products, byproducts, and wastes having a max vapor pressure of 11 psia or less under actual storage conditions.

3 Moderate Vapor Pressure Liquids include: Desulfurized Naphtha (Splitter Bottoms), Light Slop, and other refinery feedstocks, intermediates, products, byproducts, and wastes having a max vapor pressure of 1.5 psia or less under actual storage conditions.

4 Low Vapor Pressure Liquids include: Diesel (raw or finished), Kerosene (raw or finished), JP-8, CBO, LCO, Slurry, Heavy Slop, Cutback Asphalt, Cutter, VGO, AGO, and other refinery feedstocks, intermediates, products, byproducts, and wastes having a max vapor pressure less than 0.5 psia under actual storage conditions.

TABLE 2D – STORAGE TANK THROUGHPUT AND TEMPERATURE LIMITS

Material	Throughput (bbl/yr)	Maximum Storage Temperature (ºF)
Asphalt/Pitch	8,760,000	510
Carbon Black Oil	1,291,609	250
Crude	76,212,000	Ambient
Distillate	55,076,588	310
Gas Oil	25,550,000	310
Gasoline (includes isomerates)	105,353,708	Ambient
Naphtha	34,669,066	Ambient
Slop	730,000	Ambient
Sour Water	35,040	Ambient

TABLE 2E – STORAGE TANK VOC AND H_2S EMISSION LIMITS[1]

Tank Type	VOC Emission Rate (tpy)	H_2S Emission Rate (tpy)
Fixed-Roof	228.3	0.0
Floating-Roof	86.5	<0.1

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TABLE 2F

EMISSIONS RATES FOR REFINERY NON-COMBUSTION SOURCES
OF VOLATILE ORGANIC COMPOUNDS (VOC)
FUGITIVE EMISSIONS FROM EQUIPMENT LEAKS

	Process Unit ID Number	Description	Maximum Hourly VOC Emission Rate (lb/hr)	Average Annual VOC Emission Rate (tons/yr)
a, v, x	FUG-02-SP CRUDE	South Division Crude Unit	9.0	39.5
f, m, v	FUG-10-FCCU	FCCU w/CVS	10.8	47.2
h, v	FUG-20-ISOM	Powerformer/Penex Unit w/CVS	5.8	25.4
a v	FUG-21-SP VACUUM	Flasher/Vacuum Unit	2.8	12.1
a, v	FUG-05-KERO	Kerosene HDS Unit	5.2	22.7
a, m ,u, v, x	FUG-06-NHDU	JP8 Hydrodesulfurization	12.6	55.2
a, e, p, v	FUG-18-LSR MEROX TRT	Merox/Merichem Treating Units	3.5	15.3
a, v	N/A	North Division Light Straight Run Stabilizer	N/A	N/A
a, s, v	FUG-35-SAT GAS	Saturates Gas Plant	18.3	80.0
a, v, x	FUG-29-BLENDER/TK FARM	Light Oil Tankage	6.8	29.9
a, v	FUG-ASPHALT STG	Asphalt/Heavy Oil Storage	3.5	15.3
a, v	FUG-FUEL GAS	Fuel Gas Distribution System	15.9	69.7
a, v	FUG-LPG	LPG Storage System	21.6	94.4
a, v	FUG-41-PBC	PBC Unit	3.4	14.7
b, m, r, v, x	FUG-70-CCR	CCR Reformer (w/in battery limits)	23.4	102.3
g, h, m, v, x	FUG-13-NHDU	Naphtha HDS Unit	9.6	42.2
a, p ,v, x	FUG-43-S ALKY	South Alky Unit (W-76)	1.7	7.5
c, p ,v	FUG-09-N ALKY	North Alkylation Unit (New-Inside battery limits)	12.0	52.5
v	FUG-44-DIST-HDU	Gas Oil Hydrotreater (incl. CVS)	9.3	40.6
v	FUG-45-DIST-HDU	Gas Oil Hydrotreater (incl. CVS)	2.6	11.2
a, m, v	FUG-07-N AMINE	Amine Unit-Treating/Regen.	6.3	27.5
v, x	FUG-SRU1/SRU2/TGTU	SRU1/SRU2/SWS w/CVS	2.4	10.4
v	FUG-07-SWS1	Sour Water Stripper	1.6	7.0
v, x	FUG-80-WWTP CVS	Oil/Water Separator	0.6	2.6
g, m, r, v, x	FUG-33-DIST HDU	Relocated Diesel HDS Unit w/CVS	12.9	56.4
o, v, x	FUG-03-ROSE-1	ROSE Solvent De-asphalting unit	6.0	26.3
v	FUG-08-TRUCK RK	Loading Racks	2.7	11.7
v	FUG-RLO-ASPHALT	Asphalt/Pitch Loading Rack	0.3	1.1
v	FUG-73-SP UTIL	Utilities	16.7	73.3
t, v	FUG-63-H2 PLANT-1	Hydrogen Plant	2.6	11.2
v	FUG-31-SRU3/TGTU3/TGI3	SRU3 Unit	0.7	3.1
v	FUG-34-HYDROCRACKER	WX Hydrocracker	6.2	27.2
v	FUG-SAT GAS - 2	Saturates Gas	6.8	29.9
v	FUG-25-ROSE-2	ROSE Unit	8.0	35.1
v	FUG-64-H2 PLANT-2	Hydrogen Plant	2.6	11.2

Subtotal (for informational purposes only) 253.6 1110.6

a	Source in existence prior to August 31, 1972. Emission rates not affected by modifications are taken as both the potential emission rate and the potential to emit of that unit.
b	Permit No. 195-M-2
c	Permit No. 195-M-3
e	While the Naphtha HDS Unit is operating, fugitive VOC emissions from the Heavy Naphtha Merox Unit are limited to 3.40 lb/hr and 14.90 T/yr. Therefore, while the Naphtha HDS Unit is operating, total fugitive VOC emissions from the Treating Units are limited to 13.98 lb/hr and 61.24 T/yr.
f	File No.236. No permit required based on no increase in emissions over the TCCU it replaced.
g	Permit No. 195-M-5-Rev
h	Permit No. 195-M-6
i	Permit No. 195-H-4 authorized 0.27 lb/hr, 1.2 t/yr for SRU fugitive. Permit No. 195-H-7 added 0.06 lb/hr, 0.28 T/yr for tail gas cleanup unit.
j	Permit No. 195-M-10
k	Permit No. 195-M-12
l	Permit No. 195-M-13
m	Permit No. 195-M-14-R2
n	Permit No. 195-M-15
o	Permit No. 195-M-17
p	Permit No. 195-M-18
q.	Permit No. 195-M-19
r.	Permit No. 195-M-20
s.	Permit No. 195-M-21
t.	Permit No. 195-M-22
u.	Permit No. 195-M24-R1
v.	Permit No. 195-M25
x.	Permit No. 195-M25-R2

TABLE 2G

EMISSION RATES FOR REFINERY NON-COMBUSTION SOURCES
Of VOLATILE ORGANIC COMPOUNDS (VOCs)
-MISCELLANEOUS SOURCES -

	Source ID	Description	Maximum Hourly VOC Emission Rate (lb/hr)	Average Annual VOC Emission Rate (tons/yr)
b, c	TLO-1	Asphalt Truck Loading and Off-Loading Rack #1	<0.1	<0.1
b, c	TL-2	Asphalt Truck Loading Rack #2	<0.1	<0.1
a, b, c	TL-4	Fuels Truck Loading Rack	10.7	6.4
b, c	TL-5	LPG Truck Loading Rack	0.0	0.0
b, c	TL-7	CBO/LCO Truck Loading Rack	6.3	1.6
b, c	RLO-8	Railcar Loading & Off-Loading Rack	6.3	2.1
b, c	TRLO-9	Truck/Railcar Loading & Off-Loading Rack	0.1	0.1
b, c	TLO-13	Butane Truck Loading & Off-Loading Rack	28.6	7.5
b, c	TLO-14	LPG Loading & Off-Loading Rack	0.0	0.0
b, c	RLO-19	Railcar Loading & Off-Loading Rack	0.8	0.9
		Subtotal (for informational purposes only)	52.8	18.6

a Controlled emission rate. The previous controlled rate was set by the terms of the consent agreement between Navajo Refining Co. and the Department executed January 28, 1994. The agreement required that the incinerator have a minimum 90% destruction efficiency for gasoline loading and a minimum 80% destruction efficiency for diesel fuel loading or Jet A fuel loading. This was achieved by a vapor combustor. This device has since been replaced with a carbon adsorption system compliant with MACT Subpart R, as subject per MACT Subpart CC. Emission limits changed in 195-M-17 to correspond to Title V permit values.

b Permit No. 195-M25

c. Permit No. 195-M25-R2

TABLE 2H

EMISSION RATES FOR REFINERY NON-COMBUSTION SOURCES

OF VOLATILE ORGANIC COMPOUMDS and PM
-COOLING TOWERS-

notes	Source ID	VOC lb/hr	VOC tons/yr	PM (lb/hr)	PM (tons/yr)
a, c	CT Y-1	1.8	7.9	0.2	0.7
a, c	CT Y-2	1.8	7.9	0.2	0.7
a, c	CT Y-4/5	2.0	8.7	0.2	0.8
a, c	CT Y-6/7	2.2	8.7	0.2	0.8
b, c, d	CT Y-8	6.5	28.3	0.4	1.7
c	CT Y-9	1.7	7.4	0.4	1.8
c	CT TT-1	1.1	4.7	0.1	0.4
c	CT TT-2	1.1	4.7	0.1	0.4
c	CT TT-3	1.1	4.7	0.1	0.4
c	CT TT-4	0.7	3.2	0.1	0.3
c	CT TT-5	0.7	3.2	0.1	0.3
c	CT TT-6	1.1	4.7	0.1	0.4
c	CT TT-7	0.7	2.8	0.1	0.2
c	CT TT-8	0.4	1.9	<0.1	0.2
c	CT TT-9	1.1	4.7	0.1	0.41
Subtotal (for informational purposes only)		20.3	88.1	2.1	9.4

a Source in existence prior to August 31, 1972.

b Permit No. 195-M-3

c Permit No. 195-M-25

d. Permit No. 195-M-25-R2 CT- Y-8 includes 0.58 lbs/hour CO and 2.54 tpy CO. This cooling tower provides 100% control of any NH_3 emissions from V-H2 and V-H2-2.

TABLE 2I

EMISSION RATES FOR REFINERY NON-COMBUSTION SOURCES
OF VOLATILE ORGANIC COMPOUNDS (VOCs)
API OIL/WATER SEPARATORS

	Source ID	Description	Maximum Hourly VOC Emission Rate (lb/hr)	Average Annual VOC Emission Rate (tons/yr)
a, b	NOWSU	Alkylation Oil/Water Separator	0.5	2.3
b	MAIN API	Above Ground API Oil-Water Separator	2.0	8.8
b	DAF-806	Existing WWTP DAF Unit	0.6	2.7
b	NEW-API	New WWTP Oil/Water Separator	2.0	8.8
b	NEW-DAF	New WWTP DAF Unit	0.6	2.7
b	T-801/T-836/NEW-WWTK	Wastewater Surge Tanks	3.0	8.1
	Subtotal (for informational purposes only)		8.7	33.3

a Permit No. 195-M-3

b Permit No. 195-M-25

TABLE 3
MAINTENANCE STARTUP AND SHUTDOWN EMISSION LIMITS

		NOx		CO		VOC		PM		PM10		SO2		H2S	
EPN	**Description of Emissions**	**(lb/hr)**	**(tons/yr)**	**(lb/hr)**	**(tons/yr)**	**(lb/hr)**	**(tons/yr)**	**(lb/hr)**	**(tons/yr)**	**(lb/hr)**	**(tons/yr)**	**(lb/hr)**	**(tons/yr)**	**(lb/hr)**	**(tons/yr)**
H-H2-2	Emissions during SCR downtime	10.1	1.2	20.2	2.4	2.0	0.2	2.8	0.3	2.8	0.3	0.5	0.1	--	--
NAP-TK	Emissions from roof landing	--	--	--	--	169.0	2.5	--	--	--	--	--	--	--	--
NEW-SOURTK	Emissions from roof landing	--	--	--	--	33.0	0.5	--	--	--	--	--	--	--	--
-	Emissions from catalyst handling	--	--	--	--	--	--	1.5	<0.1	0.7	<0.1	--	--	--	--
SRU3-TGI	Emissions from SRU3 startup and shutdown	6.5	<0.1	15.0	0.1	0.1	<0.1	--	--	--	--	159.0	0.4	6.5	<0.1
FL-405	Emissions from depressurizing equipment to flare	21.8	0.1	118.0	0.4	7.3	<0.1	--	--	--	--	31.9	0.1	0.3	<0.1
T-0078	Emissions from roof landing and tank refilling	--	--	--	--	177.0	2.7	--	--	--	--	--	--		
T-0079	Emissions from roof landing and tank refilling	--	--	--	--	306.0	4.6	--	--	--	--	--	--		
T-1225 (formerly NAP-TK)						187.0	2.8								

TABLE 4

GLOSSARY OF TERMS USED IN THIS PERMIT

AQCR	Air Quality Control Regulation, now obsolete, replaced in 1995 by the, NMAC-format regulations
AGO	Atmospheric Gas Oil
Alky	Alkylate or Alkylation
AP42	EPA's Compilation of Air Pollutant Emission Factors
API	American Petroleum Institute
AQB	Air Quality Bureau
ASME	American Society of Mechanical Engineers
Avg	Average
BACT	Best Achievable Control Technology
Battery Limits	Physical boundary defining specific process units
BD	Bone-dry (air)
Btu	British Thermal Unit
CBG	Clean Burning Gasoline
CBO	Carbon Black Oil
CCR	Continuous Catalyst Regeneration
CDU	Crude Distillation Unit
CEM, CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CIN	Control Identification Number
CT	Cooling Tower
CVS	Closed Vent System
DAF	Dissolved Air Flotation
DAO	De-asphalted Oil
DHDU	Diesel Hydrodesulfurization Unit
DSCF	Dry standard cubic foot (60oF, 14.7 psia)
EFR	External Floating Roof (Tank)
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
FCC	Fluid Catalytic Cracking
FCCREGEN	Fluid Catalytic Cracking Regenerator
FCCU	Fluid Catalytic Cracking Unit
FX	Fixed Roof (Tank)
GOHT	Gas Oil Hydrotreater Unit
HAP	Hazardous Air Pollutant
HDS	Hydrodesulfurizer
HHV	Higher Heating Value
HOH	Hot Oil Heater
HP	High Pressure
HZ	Horizontal (Tank)
IFR	Internal Floating Roof (Tank)
LDAR	Leak Detection and Repair
LDMAR	Leak Detection Monitoring and Repair
LHV	Lower Heating Value
LNB	Low NOx Burner
LP	Low Pressure

LPG	Liquefied Petroleum Gas
LTPD	Long Tons Per Day
MACT [federal]	Maximum Achievable Control Technology, National Emission Standard for Hazardous Air Pollutants by Source Category, 40 CFR Part 63
MM	1,000,000
MMBTU	Million BTU
MW	Molecular Weight
NAAQS	National Ambient Air Quality Standards
NESHAP	[federal] National Emission Standard for Hazardous Air Pollutants, 40 CFR Part 61
NGULNB	Next Generation Ultra-Low NOx Burner
NMAC	New Mexico Administrative Code
NPR	No permit required
NSPS	[federal] New Source Performance Standards, 40 CFR Part 60
PM	Particulate Matter
pph	Pounds per hour
ppm	Parts Per Million
PRV	Pressure Relief Valve
PSD	Prevention of Significant Deterioration
PTE	Potential To Emit
PTRP	Propane Test and Release Project
ROSE	Residuum Oil Supercritical Extraction
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SRU	Sulfur Recovery Unit
SWS	Sour water stripper
TCCU	Thermofor Catalytic Cracking Unit
TDS	Total Dissolved Solids
TGI	Tail Gas Incinerator
TGTU	Tail Gas Treating Unit
TGU	Tail Gas Unit
ULNB	Ultra Low NOx Burner
ULSD	Ultra Low Sulfur Diesel
USEPA	U.S. Environmental Protection Agency
VGO	Vacuum Gas Oil
VOC	Volatile Organic Compound (per 40 CFR 60.2)
VOL	Volatile Organic Liquid (per 40 CFR 60.111b)
VRU	Vapor Recovery Unit
WGS	Wet Gas Scrubber
WWTP	Wastewater Treatment Plant