THE NAVAJO NATION

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Detailed Information

Permitting Authority: NNEPA

County: Coconino **State:** Arizona **AFS Plant ID:** 04-005-N0423

Facility: Navajo Generating Station
Document Type: STATEMENT OF BASIS

PART 71 FEDERAL OPERATING PERMIT
DRAFT STATEMENT OF BASIS
Navajo Generating Station

Permit No. NN-ROP-13-06

1. Facility Information

a. Permittee

Navajo Generating Station
5 Miles East of Page, off U.S. Highway 98
Page, Arizona 86040

Mailing Address:
P.O. Box 850
Page, Arizona 86040

Managing Participant Name: Salt River Project Agricultural Improvement and Power District (SRP)*
Managing Participant Mailing Address: P.O. Box 52025, PAB 352
Phoenix, Arizona 85072-2025

*Note: This facility is co-owned by 6 entities. SRP is listed as the managing participant in this permit since it acts as the facility operator, and has accepted the responsibility to obtain environmental permits for Navajo Generating Station, including an Acid Rain permit and Part 71 Permit. In addition to SRP (21.7%), the other 5 co-owners of this facility are:

1. U.S. Bureau of Reclamation (USBR) (24.3%)
2. Los Angeles Department of Water and Power (LADWP) (21.2%)
3. Arizona Public Service Company (APS) (14.0%)
4. Nevada Power Company (NPC) (11.3%)
5. Tucson Electric Power (TEP) (7.5%)

b. Contact Information

Facility Contact:	Paul Ostapuk O&M Manager	Phone: (928) 645-6577 Facsimile: (928) 645-7298
Responsible Official:	Robert K. Talbot Plant Manager	Phone: (928) 645-6217 Facsimile: (928) 645-7298

c. Description of Operations, Products

The facility is a 2,250 net Megawatt coal-fired power plant. Bituminous coal is mined by Peabody Energy at the Kayenta Mine complex and delivered by electric rail to NGS. Coal is then transferred via enclosed conveyor systems to the boilers or to a storage pile for later use.

The management of coal combustion residues and the delivery of limestone for the SO_2 scrubbers is contracted to a third party entity but SRP remains the responsible party for truck loading and unloading operations, material transfer, storage, and disposal activities. Coal combustion residues include fly ash, bottom ash, and scrubber byproducts. Bottom ash and scrubber byproducts are handled in a wet state which minimizes the potential for dust emissions.

d. History

The facility consists of three (3) coal-fired utility boilers and two oil-fired auxiliary boilers. The permittee receives the coal, which has an average sulfur content between 0.5% and 0.75% by weight, from a nearby coal mine. Coal-fired boilers U1, U2, and U3 and oil-fired auxiliary boilers AUX-A and AUX-B commenced construction in 1970. The construction of these boilers predated EPA's preconstruction permit regulations.

Particulate emissions from boilers U1 through U3 are controlled by Electrostatic Precipitators (ESP). Flue Gas Desulfurization (FGD) systems for SO_2 control were installed in 1997, 1998, and 1999 on boilers U3, U2, and U1, respectively. The associated limestone handling system was constructed in 1997. In 2008, the source received a PSD permit to install Low-NO_X burners (LNBs) and Separated Over-fire Air (SOFA) systems on the three existing boilers. The LNB/SOFA systems were installed in 2009, 2010, and 2011 on boilers U3, U2, and U1, respectively.

e. Existing Approvals

The source has been operating under Part 71 Operating Permit NN-ROP-05-06, issued on July 3, 2008, and the following approvals:

(a) PSD Permit #AZ 08-01, issued on November 20, 2008.

(b) Title V Permit Reopening #NN-ROP-05-06-A, issued on October 28, 2011.

(c) PSD Permit Amendment #AZ 08-01A, issued on February 6, 2012.

f. Proposed Modifications to the Part 71 Permit:

The permittee requested the following changes made to their Part 71 permit:

(1) Changes to the maximum heat input capacity of the boilers:
The maximum heat input capacity for each of the boilers U1, U2, and U3 has been reduced from 7,725 MMBtu/hr to 7,410 MMBtu/hr. This change was requested by the permittee because the heating value of coal received at this plant has decreased in recent years and the revised heat input of 7,410 MMBtu/hr for each boiler better reflects the estimated maximum boiler capacity. This change will not result in increases of emissions from these units and is considered a minor permit modification.

(2) Revise the insignificant activities listed:
The list of insignificant activities and emissions in Section 1.j of this Statement of Basis has been updated based on information submitted by the permittee on July 24, 2014. The new emergency fire pump (NGS-120A) is subject to the New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII) and the applicable requirements of this NSPS will be included in this Part 71 permit. These changes are considered a significant permit modification.

(3) Update the unit description for coal hopper feeders (L1-L12):
The permittee installed a wet dust suppression system (Mee Fog System) to control the twelve (12) coal hopper feeders (L1-L12) in 2007. This information was not include in the permit application for the previous Part 71 permit, issued on January 4, 2008. However, the installation of this control equipment decreases the particulate emissions from these units and is considered a minor permit modification.

(4) Add operating limits for auxiliary boilers AUX A and AUX B:
In order to be qualify for "limited-use" units under 40 CFR Part 63, Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters), the permittee requested to include an operating limit of 10% of the annual capacity into this Part 71 renewal permit for the auxiliary boilers. This Part 71 permit will also include additional recordkeeping requirements for these auxiliary boilers. These proposed changes are considered significant permit modifications.

(5) Installation of PM CEMS with Boilers U1, U2, U3:
In an addendum to Title V renewal application received on January 21, 2015, the permittee stated that has elected to comply with the new PM emission limit in National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (NESHAP, Subpart UUUUU) and new PM Continuous Emission Monitoring Systems (CEMS) have been installed and operated for each of the boilers U1, U2, U3 to show compliance with the PM emission limit in this NESHAP. Since the PM emission limit in this NESHAP, Subpart UUUUU is most stringent applicable PM emission limit for boilers U1, U2, and U3, operating PM CEMS according to the NESHAP requirements exempts the permittee from Continuous Assurance Monitoring (CAM) requirements (40 CFR Part 64). The permittee requested the existing CAM requirements be removed from the Part 71 renewal permit. This change is considered a significant permit modification.

The procedure for reviewing this Part 71 renewal permit fulfills the minor permit modification requirements specified in 40 CFR § 71.7(e)(1) and NNOPR § 405(D), and the significant permit modification requirements specified in 40 CFR § 71.7(e)(3) and NNOPR § 405(E).

g. Permitted Emission Units and Control Equipment

Unit ID/ Stack ID	Unit Description	Maximum Capacity	Commenced Construction Date	Control Method
U1/ Stack S1	One (1) pulverized coal-fired boiler, using No. 2 fuel oil for ignition fuel. Stack S1 is equipped with SO_2, NO_X, CO, and PM CEMS and a COMS.	7,410 MBtu/hr; 750 Net MW	1970	ESP1; FGD system SCBR1 (1999); LNB/SOFA*(2011)
U2/ Stack S2	One (1) pulverized coal-fired boiler, using No. 2 fuel oil for ignition fuel. Stack S1 is equipped with SO_2, NO_X, CO, and PM CEMS and a COMS.	7,410 MBtu/hr; 750 Net MW	1970	ESP2; FGD system SCBR2 (1998); LNB/SOFA*(2010)
U3/ Stack S3	One (1) pulverized coal-fired boiler, using No. 2 fuel oil for ignition fuel. Stack S1 is equipped with SO_2, NO_X, CO, and PM CEMS and a COMS.	7,410 MBtu/hr; 750 Net MW	1970	ESP3; FGD system SCBR3 (1997); LNB/SOFA*(2009)
AUX A	One (1) auxiliary boiler; using No. 2 fuel oil as fuel	308 MMBtu/hr	1970	N/A
AUX B	One (1) auxiliary boiler; using No. 2 fuel oil as fuel	308 MMBtu/hr	1970	N/A
Coal Handling Operations				
CT1	One (1) railcar unloading operation	10,000 tons/hr	1970	wet suppression
L1 - L12	Twelve (12) hopper feeders	2,400 tons/hr (total)	1970	wet suppression
BC-1 through BC-4	Four (4) conveyors to the yard surge bin	1,800 tons/hr (each)	1970	DC-8
BC-4A	One (1) conveyor to the batch weight system	100 tons/hr	1970	DC-8

Unit ID/ Stack ID	Unit Description	Maximum Capacity	Commenced Construction Date	Control Method
BFD-5A, BC-5	Two (2) reclaim conveyors	1,800 tons/hr (each)	1970	DC-8
BC-6	One (1) conveyor to the yard surge bin	1,500 tons/hr	1970	DC-8
BC-6A through BC-6C	Three (3) conveyors to the stacker/reclaimer	1,800 tons/hr (each)	1970	wet suppression/ enclosure
BC-7	One (1) conveyor to the emergency reclaim hopper	1,500 tons/hr	1970	wet suppression
YSB-1	One (1) yard surge bin	1,800 tons/hr	1970	DC-8
BC-8A, BC-8B	Two (2) conveyors to plant surge bin	1,500 tons/hr (each)	1970	DC-8
BC-8AS, BC-8BS	Two (2) screens	1,500 tons/hr (each)	1970	DC-8
PSB-1	One (1) plant surge bin	3,000 tons/hr	1970	DC-5
BC-9A, BC-9B	Two (2) conveyors to the coal silos for boilers U1 and U2	1,500 tons/hr (each)	1970	DC-5
BC-10A, BC-10B	Two (2) conveyors to the coal silos for boiler U3	1,500 tons/hr (each)	1970	DC-5
CC-1A through CC-9A; CC-1B through CC-9B	Three (3) enclosed cascading conveying systems to the coal storage silos for boilers U1, U2, and U3	1,500 tons/hr (each)	1970	DC-1 through DC-4, DC-6, and DC-7
Silos 1A through 1G	Seven (7) storage silos for boiler U1	3,000 tons/hr (each)	1970	DC-1, DC-2, and baghouse PR-1.
Silos 2A through 2G	Seven (7) storage silos for boiler U2	3,000 tons/hr (each)	1970	DC-3, DC-4, and baghouse PR-2.
Silos 3A through 3G	Seven (7) storage silos for boiler U3	3,000 tons/hr (each)	1970	DC-6, DC-7, and baghouse PR-3.
CS	Outdoor coal storage piles	3,300 tons/hr (total)	1970	wet suppression
Limestone handling system associated with the FGD systems				
Unloading Bay A and B	Two (2) truck unloading operations	38 tons/hr (each)	1997	N/A
O-LSH-HOP-A	One (1) limestone unloading hopper	300 tons/hr	1997	DC-9
O-LSH-HOP-B	One (1) limestone unloading hopper	300 tons/hr	1997	DC-10
O-LSH-FDR-A	One (1) conveyor	300 tons/hr	1997	DC-9
O-LSH-FDR-B	One (1) conveyor	300 tons/hr	1997	DC-10
O-LSH-CNV-A	One (1) conveyor	300 tons/hr	1997	DC-9
O-LSH-CNV-B	One (1) conveyor	300 tons/hr	1997	DC-10
O-LSH-SILO-A and B	Two (2) limestone storage silos	300 tons/hr (each)	1997	DC-11
O-LSP-FDR-A and B	Two (2) enclosed feeders to the slurry preparation system	36 tons/hr (each)	1997	N/A
O-LSP-CNV-A and B	Two (2) enclosed cleanout conveyors	5 tons/hr (each)	1997	N/A
O-LSP-MILL-A and B	Two (2) ball mills	36 tons/hr (each)	1997	N/A
LS	Limestone storage piles	600 tons/hr (total)	1997	wet suppression
Fly ash handling system				
Silo 1	One (1) fly ash bin for boilers U1 and U2	46 tons/hr	1970	DC-S1/2
Silo 2	One (1) fly ash bin for boiler U3	46 tons/hr	1970	DC-S3

Unit ID/ Stack ID	Unit Description	Maximum Capacity	Commenced Construction Date	Control Method
Silo 1 and 2 Loading	Two (2) partially enclosed fly ash truck loading operations	38 tons/hr (each)	1970	DC-S1/2 and DC-S3
DWB-A through DWB-F	Six (6) bottom ash truck loading operations. The bottom ash is processed in a wet form	46 tons/hr (each)	1970	wet suppression
Soda ash/lime handling systems				
SAB-1A, SAB-2A, SAB-1B, SAB-2B	Four (4) soda ash storage bins	0.4 tons/hr (each)	1970	dust collector BH-6
LB-1 and LB-2	Two (2) lime storage bins	0.57 tons/hr (each)	1970	dust collector BH-7
Miscellaneous Operations				
	Six (6) cooling towers	813,000 gal/min (total)	1970	N/A
TR	Fugitive emissions from unpaved roads	N/A	1970	wet suppression

*Note: LNB/SOFA = Low-NO_X burner (LNB) and Separated Overfire Air (SOFA) system.

h. Unpermitted Emission Units and Control Equipment

No unpermitted emission units were found to be operating at this source during this review process.

i. New Emission Units and Control Equipment

There is no new emission unit or control equipment proposed during this review process.

j. Insignificant Activities and Emissions

This stationary source also emits air pollutants from insignificant activities and at insignificant emissions levels, defined in 40 CFR § 71.5(c)(11)(ii) as emissions from an emissions unit with the potential to emit non-hazardous regulated air pollutants in an amount less than 2 tons per year or a single HAP in an amount less than 1,000 pounds per year or the de minimis level established under CAA § 112(g), whichever is less. These emissions come from the following insignificant activities and emissions units:

(a) Nine (9) diesel-fired emergency generators, as specified in Table 1 below:

Table 1 – Diesel-Fired Emergency Generators

Unit ID	Unit Description	Installation Date	Max. Power Output (hp)	Type of Engine* (CI or SI)
EG1	Emergency generator for boilers U1 and U2	1983	515	CI
EG2	Emergency generator for boiler U3	1976	280	CI
EG3	Warehouse emergency generator	Before 4/1/2006	70	CI

Unit ID	Unit Description	Installation Date	Max. Power Output (hp)	Type of Engine* (CI or SI)
NPG-746	Emergency generator	2003	469	CI
NGS-120A	Emergency fire pump	2010	300	CI
NPG-529	Portable generator	1987	335	CI
NPG-384	Portable generator	1977	141	CI
NPG-811	Portable generator	2007	34	CI
NPG-818	Portable generator	2007	717	CI

*Note: CI = Compression Ignition; SI = Spark Ignition

(b) Equipment used during facility-wide welding activities, identified as WL.

(c) Equipment used during abrasive blasting operations.

(d) Fuel and oil storage tanks as described in Table 2 below:

Table 2 - Fuel and Oil Storage Tanks

Unit ID	Type of Liquid Stored	Construction Date	Max. Capacity (gallons)
NGS-062A	Diesel	1991	14,000
NGS-063A	Diesel	1991	14,000
NGS-064A	Gas	1991	12,000
NGS-065A	Used Oil	1991	2,500
NGS-067A	Used Oil	1991	550
NGS-068A	30 Wt Engine Oil	1991	550
NGS-070A	30 Wt Engine Oil	1991	550
NGS-071A	10 Wt Engine Oil	1991	550
NGS-072A	Diesel	1991	2,000
NGS-073A	Diesel	1991	10,000
NGS-074A	Diesel	1991	10,000
NGS-075A	Diesel	1974	5,040,000
NGS-075B	Diesel	2000	172,000
NGS-076A	Clean Lube Oil	1973	16,000
NGS-077A	Dirty Lube Oil	1973	16,000
NGS-078A	10 Wt Engine Oil	1991	550
NGS-079A	Mobile Diesel	Early '70s	200
NGS-080A	Mobile Diesel	Early '70s	200
NGS-081A	Mobile Diesel	Early '70s	200
NGS-082A	30 Wt Engine Oil	1991	550
NGS-083A	10 Wt Engine Oil	1991	550
NGS-084A	Mobile Diesel	Early '70s	200
NGS-085A	Mobile Diesel	1974	400
NGS-086A	Mobile Diesel	1974	350
NGS-088A	Mobile Diesel	1974	400
NGS-090A	Turbine Lube Oil	1974	7,450
NGS-091A	Turbine Lube Oil	1974	650
NGS-092A	Turbine Lube Oil	1974	650
NGS-093A	Turbine Lube Oil	1975	7,450

Unit ID	Type of Liquid Stored	Construction Date	Max. Capacity (gallons)
NGS-094A	Turbine Lube Oil	1975	650
NGS-095A	Turbine Lube Oil	1975	650
NGS-096A	Turbine Lube Oil	1976	7,450
NGS-097A	Turbine Lube Oil	1976	650
NGS-098A	Turbine Lube Oil	1976	650
NGS-099A	H2 Seal Oil	1975	650
NGS-100A	H2 Seal Oil	1974	650
NGS-101A	H2 Seal Oil	1976	650
NGS-102A	Transformer Oil	1973	5,600
NGS-103A	Transformer Oil	1973	5,750
NGS-104A	Transformer Oil	1973	5,750
NGS-106A	Diesel	1974	10,000
NGS-107A	Lube Oil	1991	750
NGS-108A	Diesel	1991	900
NGS-109A	Diesel	1974	400
NGS-110A	Lube Oil	1982	300
NGS-111A	Lube Oil	1982	300
NGS-112A	Lube Oil	1982	300
NGS-113A	Used Diesel	2012	500
NGS-113B	Used Diesel	2012	500
NGS-113C	Used Diesel	2012	500
NGS-114A	Diesel	2002	100
NGS-115A	Diesel	Unknown	200
NGS-116A	Diesel	2002	100
NGS-117A	Diesel	2003	500
NGS-118A	Diesel	2003	500
NGS-119A	Diesel	1991	150
NGS-120A	Diesel	2010	150
NGS-121A	Lube Oil	N/A	550
NGS-122A	Diesel	2003	500
NGS-123A	Diesel	2002	140
NGS-124A	Diesel	N/A	100
NGS-125A	Diesel	Unknown	200
NGS-126A	Variouse Oils	2008	12 tanks, \60 gal each
NGS-127A	Diesel/Unleaded Fuel	2005	550/100
NGS-128A	Diesel/Unleaded Fuel	2005	550/100
NGS-129A	Diesel	Unknown	200
NGS-130A	Diesel	2002	100
NGS-131	Used Oil for Heating	N/A	550
NGS-131A through 131O	Used Oil	1991	540 (each)
NGS-132A	Diesel	2002	100
NGS-133A	Diesel	2002	100
NGS-134A through 134D	Used Oil	N/A	250 (each)
NGS-135	Used Oil	N/A	100

(e) Landscaping, building maintenance, or janitorial activities.

(f) Hand-held or manually operated equipment used for buffing, polishing, carving, cutting, drilling, machining, routing, sanding, sawing, surface grinding, or tuning of precision parts, metals, plastics, masonry, glass, or wood.

(g) Equipment used during powder coating operations.

(h) Lab equipment used exclusively for chemical and physical analyses.

(i) Equipment used during maintenance painting and surface coating.

(j) Equipment used during parts cleaning.

(k) Equipment used during maintenance sand blasting.

(l) Other emissions units with the potential to emit insignificant levels of regulated air pollutants or HAPs, as described in Table 3 below:

Table 3 - Other Emissions Units with Insignificant Emissions Levels

Unit Description	Max. Capacity (gallons)	Number of Units
Main turbine lube oil reservoir	7,450	3
M T lube oil filter canisters	100	6
Aux turbine lube oil reservoir	650	2
Electro hydraulic control reservoir	400	3
Pulverizer lube oil reservoir	100	7
Pulverizer lube oil reservoir	300	14
Condensate pump reservoir	85	9
Boiler Feed BP oil reservoir	22	9
Inst / service air compressor	50	9
Soot blowing air compressor	250	3
Primary air fan	85	6
Induced draft fan	110	12
Forced draft fan	10	6
Coal belt gear case	35	35
Cooling tower circ pump	10	6
Cooling fan gear case	34	30
Brine concentrator compressor	100	1
Brine concentrator compressor	150	2
Chrystallizer compressor	275	1
Transformer (spare) (mineral oil)	265	2
Emergency diesel fire pump	250	1
Transformer (main)	9,550	12
Transformer (aux)	6,672	3
Transformer (main station service)	21,980	1

Unit Description	Max. Capacity (gallons)	Number of Units
Transformer (main station service)	17,730	1
Reactor tank	5,500	12
Reactor tank	6,142	12
Thyrite varister oil tank	2,446	12
Large capacitor oil tanks	3.2	5,581
Small capacitor oil tanks	2.8	2,210
Transformer (50 KV at RR)	4,180	3
Circuit breaker oil tank (230 KV)	2,575	5
Transformer 4,160 V	1,409	14
Transformer 4,160 V	1,193	2
Transformer 480 V	268	28
Transformer 480 V	338	30
Transformer 480 V	343	5
Transformer/rectifier set	165	80
Transformer/rectifier set	140	32
Transformer/rectifier set	132	64
Transformer/rectifier set	117	64
Transformer 4,160 V (lake pump)	1,259	3
Transformer 480 V (lake pump)	160	2
Waste oil storage tank (cent yard)	500	1
Generator, diesel (Generac)	265	1
Recycle slurry system gear box	16	12
Recycle slurry system gear box	22	12
Oxidation air system oil res.	60	9
Recycle valve Hydraulic sys.	120	3
Reactivator agitator	13	30
Limestone feed tank agitator	24	3
Absorber sump agitator	0.75	6
Ball mill gear box	52	2
Ball mill lube reservoir tank	110	2
Limestone conveyor gear box	39	3
Limestone transfer tank agitator	44	1
Filtrate raw water tank gear box	44	1
Ball mill sump tank agitator	7	2
LSP sump agitator	0.75	3
Filtrate transfer tank agitator	24	1
Secondary vacuum pump gear box	4.5	3
Absorber holding tank agitator	23	10
Bi-product sump agitator	1.5	2
Primary dewatering agitator	2	6
Conveyer feedbelt gear box	1.5	2
Antifreeze storage tank (NGS-069A)	550	1
Waste antifreeze storage tank (NGS-066A)	1,000	1
Sulfuric acid tank (NGS-201)	20,000	1
Sulfuric acid tank (NGS-202, 203, and 204)	15,000	3
Sulfuric acid tank (NGS-205)	10,000	1
Ammonia tank (NGS-208)	10,000	1

Unit Description	Max. Capacity (gallons)	Number of Units
Ferric chloride tank (NGS-209)	16,000	1
Acid or caustic tank (NGS-210 and 211)	24,000	2
Sodium hydroxide tank (NGS-206 and 207)	10,000	2
Sodium hypochlorite tank (NGS-212, 213, and 214)	4,500	3
Scale inhibiter tank (NGS-215 through 220)	2,000	6
Dust Suppressant (Dusbloc) Tank	1,000	1
Dust Suppressant (Dusbloc) Tank	4,000	1

k. Enforcement Issue

There are no enforcement actions pending.

l. Emission Calculations

See Appendix A of this document for detailed calculations (pages 1 through 16).

m. Potential to Emit

Potential to emit (PTE) means the maximum capacity to emit any CAA-regulated air pollutant under the facility's physical and operational design. Any physical or operational limitation on the maximum capacity of this facility to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, may be treated as a part of its design if the limitation is enforceable by US EPA or NNEPA. Actual emissions are typically lower than PTE.

	Potential to Emit (tons/year)							
Process/facility	PM	PM10	PM2.5	SO_2	NOx	VOC	CO	HAPs
Boiler U1	1,947	1,097	488	3,246	7,789	75.3	4,868	22.7
Boiler U2	1,947	1,097	488	3,246	7,789	75.3	4,868	22.7
Boiler U3	1,947	1,097	488	3,246	7,789	75.3	4,868	22.7
Auxiliary Boilers	3.92	1.96	0.49	13.9	47.1	0.39	9.81	1.19
Coal Handling	5.91	3.41	2.51	-	-	-	-	-
Coal Piles (Fugitive)	5.43	2.57	0.39	-	-	-	-	-
Limestone Handling	4.61	2.98	2.98	-	-	-	-	-
Limestone Piles (Fugitive)	4.60	2.17	0.33	-	-	-	-	-
Fly Ash Handling	29.2	29.2	29.2	-	-	-	-	0.01
Soda Ash/Lime Handling	0.26	0.26	0.26	-	-	-	-	-
Cooling Towers	19.2	19.2	19.2	-	-	-	-	-
Unpaved Roads (Fugitive)	546	141	14.1	-	-	-	-	-
Emergency Generators (Insignificant)	1.57	1.57	1.57	1.47	22.2	1.77	4.78	Negligible
Other Insignificant Activities*	15.3	15.3	15.3	-	-	Less than 5.00	-	Negligible
PTE of the Entire Source	6,478	3,512	1,549	9,752	23,437	233	14,620	69.3
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10 for a single HAP and 25 for total HAPs

*Note: This is an estimate on the PM/PM10/PM2.5 emissions from the welding and blasting operations, and VOC/HAP emissions from the parts cleaning, surface coating operations, and the storage tanks.

(a) The potential to emit of PM_{10}, $PM_{2.5}$, SO_2, VOC, CO and NO_x are equal to or greater than 100 tons per year. In addition, the potential to emit of HAPs from this source is greater than 10 tons per year of a single HAP and greater than 25 tons per year of total HAPs. Therefore, this source is considered a major source under 40 CFR § 71.2 (defining "major source" for purposes of the Federal Operating Permit Program).

(b) This source is located in an attainment area and is in one of the 28 source categories listed in 40 CFR § 52.21(b)(1)(i)(a). The potential to emit PM and all relevant criteria pollutants of this source is greater than 100 tons per year. Therefore, this source is an existing major source under the Prevention of Significant Deterioration (PSD) program.

n. Actual Emissions

The following table shows the actual emissions from the source. This information reflects the 2012 emission inventory data submitted by the permittee to NNEPA and the greenhouse gas (GHG) information reported to U.S. EPA under the GHG reporting program (40 CFR Part 98).

Pollutant	Actual Emissions (tons/year)
PM_{10}	432
SO_2	4,404
VOC	200
NO_X	16,276
Hydrogen Chloride	6.0
Hydrogen Fluoride	9.0
Greenhouse Gas (GHG)	17,022,237

2. Tribe Information

a. General

The Navajo Nation has the largest land base of any tribe in the country, covering more than 27,000 square miles in three states: Arizona, Utah, and New Mexico. The Navajo Nation currently is home to more than 260,000 people. Industries on the Navajo Nation include oil and natural gas production, coal and uranium mining, electric generation and distribution, and tourism.

b. Local air quality and attainment status

All areas of the Navajo Nation are currently designated as attainment or unclassifiable for all pollutants for which a National Ambient Air Quality Standard (NAAQS) has been established.

3. Prevention of Significant Deterioration (PSD) Applicability

This source is in one of the 28 source categories listed in 40 CFR § 52.21(b)(1)(i)(a) and has potential to emit PM and all relevant criteria pollutants greater than 100 tons per year. Therefore, this source is considered an existing PSD major source. This source commenced construction in 1970 and commenced modifications in 1997 (installation of the FGD systems) and 2008 (installation of LBN/SOFA systems). The construction of this source predated the PSD applicability date of June 1, 1975. Therefore, this source was not required to obtain a preconstruction permit when it was constructed in 1970. The modifications in 1997 (installation of the FGD systems) did not result in an emissions increase above the PSD significance thresholds in 40 CFR § 52.21. Therefore, the modification that commenced in 1997 did not trigger PSD.

A PSD permit was issued to this source on July 3, 2008 for the installation of LNB/SOFA systems for the existing three boilers U1 through U3. An amendment to this PSD permit was issued on February 8, 2012. According to the requirements in the amended PSD permit, the permittee is required to comply with the following emission limits for each of the boilers U1 through U3:

(a) CO emissions shall not exceed the following (BACT requirements):

(1) 0.23 lb/MMBtu based on a 30-day rolling average, and

(2) 0.15 lb/MMBtu based on a 12-month rolling average.

(b) NO_X emissions shall not exceed 0.24 lb/MMBtu based on a 30-day rolling average.

In addition, the permittee is required to install CO CEMS (Continuous Emissions Monitoring System) to demonstrate compliance with the CO emission limits specified in the PSD permits.

The above emission limits and the associated compliance monitoring, recordkeeping, and reporting requirements have been included in this Part 71 permit renewal.

4. Federal Rule Applicability

(a) This source is subject to the source-specific Federal Implementation Plan (FIP) for Navajo Generating Station, Navajo Nation (40 CFR § 49.5513) which was promulgated on March 5, 2010 and later amended on August 8, 2014 to incorporate the Regional Haze Best Available Retrofit Technology (BART) requirements.

Pursuant to 40 CFR § 49.5513(d), the permittee shall comply with the following emission limits on a plant-wide basis:

(1) The SO_2 emissions shall not exceed 1.0 lb/MMBtu averaged over any three-hour period;

(2) The PM emissions shall not exceed 0.06 lb/MMBtu as averaged from at least three sampling runs per stack, each at a minimum of 60 minutes in duration and collecting a minimum sample of 30 dry standard cubic feet;

For the stacks of Units U1, U2, and U3, opacity shall not exceed 20% averaged over a 6 minute period, excluding condensed water droplets, or 40% averaged over 6 minutes during absorber upset transition periods, pursuant to 40 CFR § 49.5513(d)(4).

For dust emissions associated with coal transfer and storage and other dust-generating activities, opacity shall not exceed 20%, as determined using 40 CFR Part 60, Appendix A-4, Method 9. The permittee is required to operate and maintain the existing dust suppression methods for controlling dust from the coal handling and

storage facilities. A dust control plan was submitted by the permittee on June 4, 2010 and a revised plan was received on February 2, 2015. The revised dust control plan is included in this Part 71 permit renewal as Attachment A.

The permittee shall also comply with the testing, monitoring, reporting, and recordkeeping requirements specified in 40 CFR § 49.5513(e) and (f).

This FIP was amended on August 8, 2014 to include BART requirements (effective October 7, 2014). Pursuant to 40 CFR § 49.5513(j)(3), total cumulative NO_X emissions from Units 1, 2, and 3, from January 1, 2009 to December 31, 2044 shall not exceed the 2009-2044 NO_X Cap (494,899 tons). Compliance with this NOx emission limit must be demonstrated by the operation of the existing NO_X CEMS. The applicable operating, maintenance, recordkeeping, and reporting requirements for the NOx CEMS specified in the FIP have been incorporated into this Part 71 permit.

This FIP also requires the source to select and implement one of four operating scenarios listed under 40 CFR § 49.5513(j)(3)(i) to ensure compliance with the NO_X emission cap limit. However, pursuant to 40 CFR § 49.5513(j)(4)(i), the permittee has until December 1, 2019 to notify U.S. EPA of its choice of operating scenario. Therefore, the requirements associated with these four operating scenarios are not included in this Part 71 permit. Pursuant to 40 CFR § 49.5513(j)(4)(iii), the source is required to submit a permit revision application no later than December 31, 2020 to incorporate the specific requirements, including compliance monitoring, recordkeeping, and reporting requirements, associated with the selected operating scenario.

(b) The existing boilers U1 through U3 are considered utility units under the definition of 40 CFR § 72.2. Therefore, these boilers are subject to the Acid Rain Program requirements (40 CFR Part 72 through 40 CFR Part 78), pursuant to 40 CFR § 72.6(a)(3). An Acid Rain Renewal Application was received on June 19, 2013 and the renewal of the acid rain permit will be issued with this Part 71 permit renewal. Pursuant to 40 CFR § 72.9, the permittee shall comply with the following:

(1) The SO_2 and NO_X continuous emission monitoring requirements in 40 CFR Part 75.

(2) Acid rain emissions limitations for sulfur dioxide in 40 CFR Part 73. Pursuant to 40 CFR § 73.10(b) and the allowance allocations provided on October 30, 2000, the phase II SO_2 allowance allocations for the boilers at this source are listed in the table below:

Emission Unit	SO_2 Allowance for years 2010 and beyond (tons/yr)
Boiler U1	24,949
Boiler U2	23,354
Boiler U3	23,693
Facility Total	71,996

Beginning in 2007, the SO_2 allowance allocations apply to the entire facility, instead of each individual emission unit at this facility.

(3) Acid rain emissions limitations for nitrogen oxides in 40 CFR Part 76 for coal-fired boilers. Beginning in calendar year 2008, the permittee shall comply with the NOx emission limit of 0.40 lbs/MMBtu for each of the boilers U1, U2, and U3, pursuant to 40 CFR § 76.7(a)(1).

(c) 40 CFR § 52.145(d) (Visibility Protection) includes the following specific requirements for the three (3) coal-fired boilers at Navajo Generating Station: (1) Pursuant to 40 CFR § 52.145(d)(2), the SO_2 emissions from each of the coal fired boilers (boilers U1, U2, and U3) shall not exceed 42 ng/J (0.1 lbs/MMBtu) heat input; and (2) Pursuant to 40 CFR § 52.145(d)(3), compliance with the emission limit shall be determined daily on a plant-wide rolling annual basis.

(d) This source is subject to the Regional Haze Rule (40 CFR § 51.308) because it is a BART-eligible source (that is, a fossil-fuel fired steam electric plant of more than 250 MMBtu/hr heat input which was not in operation prior to August 7, 1962, was in existence on August 7, 1977, and has the potential to emit greater than 250 tons per year of any air pollutant, see 40 CFR § 51.301) that may reasonably be anticipated to cause or contribute to any impairment of visibility in a mandatory Class I area. Pursuant to 40 CFR § 51.308(e), States are required to submit implementation plans that, among other measures, contain either emission limits representing Best Available Retrofit Technology (BART) for BART-eligible sources that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area, or alternative measures that provide for greater reasonable progress than BART. Under the Clean Air Act, 42 USC § 7601(d), and the Tribal Authority Rule, 40 CFR § 49.11(a), EPA may promulgate a federal implementation plan in the absence of a tribal implementation plan. Under this authority, EPA promulgated a source-specific FIP containing BART requirements for this source; the FIP is codified at 40 CFR § 49.5513(j).

(e) The Clean Air Mercury Rule (CAMR, CAA § 112(n)) was promulgated on May 18, 2005 and was developed to permanently cap and reduce the mercury (Hg) emissions from coal-fired power plants. However, on February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision that vacated the Clean Air Mercury Rule. *See New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008). Therefore, CAMR requirements are not included in this Part 71 permit renewal. However, mercury emissions from utility power plants are regulated under 40 CFR Part 63,

Subpart UUUUU (see below for discussion of applicable 40 CFR Part 63, Subpart UUUUU requirements).

(f) This existing source is a major source for HAPs. The three boilers at this source (U1 through U3) are considered existing coal-fired electric generating units (EGUs) and are subject to National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63, Subpart UUUUU), which were promulgated on February 16, 2012 and later revised on November 19, 2014.

Pursuant to 40 CFR § 63.9984(b), facilities subject to subpart UUUUU must comply with the requirements of this NESHAP by April 16, 2015, unless they receive approval for an extension to the compliance date under 40 CFR § 63.6(i). The permittee requested an extension on the compliance date for the mercury provisions of this NESHAP due to the technical difficulties associated with installing add-on mercury controls. This extension request was granted by U.S. EPA and NNEPA on January 27, 2014. The extended compliance date for the mercury provisions is April 16, 2016. The source must also comply with the following implementation schedule included in the extension approval letter:

(1) By April 1, 2015, submit to NNEPA a title V permit modification application that incorporates the final mercury control strategy.

(2) By October 1, 2015, commence construction to incorporate the mercury control strategy on-site.

(3) By April 16, 2016, complete on-site construction and comply with all mercury provisions of this NESHAP.

The permitee is also required to submit interim progress reports and a final report to NNEPA and U.S. EPA.

The permittee shall comply with the following emission limits, pursuant to 40 CFR § 63.9991(a) and Table 2 of this NESHAP:

(1) By April 16, 2015, filterable PM emissions shall not exceed 0.03 lb/MMBtu or 0.3 lb/MWh.

(2) By April 16, 2015, SO_2 emissions shall not exceed 0.2 lb/MMBtu or 1.5 lb/MWh.

(3) By April 16, 2016, Mercury (Hg) emissions shall not exceed 1.2 lb/TBtu or 0.013 lb/GWh.

The permittee has elected to use PM CEMS and SO_2 CEMS to demonstrate compliance with the filterable PM and SO_2 emissions limit. The associated

compliance, monitoring, testing, notification, recordkeeping, and reporting requirements, regarding to PM and SO_2 emissions, are included in the permit as Attachment C.

Since the control device and compliance methods for mercury have not yet been determined, the detailed monitoring, testing, recordkeeping, and reporting requirements regarding to Hg emissions under this NESHAP are not included in this Part 71 renewal permit. The permittee plans to submit the permit modification for Hg compliance plans in 2015.

(g) Each of the boilers at this source (U1 through U3, AUXA, and AUXB) has a maximum heat input greater than 250 MMBtu/hr. However, these boilers commenced construction before August 17, 1971 and the permittee stated that no modification or reconstruction to the boilers has occured since the construction of these boilers. Therefore, the New Source Performance Standards (NSPS) for Fossil-Fuel-Fired Steam Generators (40 CFR Part 60, Subpart D), which apply to generators that commenced construction or modification after August 17, 1971, are not applicable to the boilers at this source.

(h) This existing source is a major source for HAPs. Boilers U1 throught U3 are subject to NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63, Subpart UUUUU). Therefore, these three boilers are not subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR Part 63, Subpart DDDDD), pursuant to 40 CFR § 63.7491(a). However, the No. 2 fuel oil-fired auxiliary boilers (AUX A and AUX B) are subject to this NESHAP. According to the initial notification submitted by the permittee on May 30, 2013, the auxiliary boilers operate less than 10% of the annual capacity and are considered "limited-use" units, as defined in 40 CFR § 63.7575.

Pursuant to 40 CFR § 63.7500(c), limited-use boilers are only required to complete a tune-up every 5 years. There are no specific emission limits, energy assessment, or operating limits for these type of boilers. Pursuant to 40 CFR § 63.7495(b), the compliance date for the existing affected units is January 31, 2016.

In addition, 40 CFR § 63.7555(d)(3) requires the permitting authority to include a federally enforceable condition in the permittee's Part 71 permit to limit the operation of the auxiliar boilers (AUX A and AUX B) to not more than 10% of the annual capacity for each unit, in order to ensure they continue to qualify for "limited-use" unit status. The permittee has requested the inclusion of this opertating limit in the Part 71 renewal permit.

(i) The coal handling operations at this source process more than 200 tons of coal per day. However, all of the coal handling operations at this source commenced construction before October 24, 1974 and the permittee stated that no modification to the coal handling operations has occured since the construction of these units.

Therefore, pursuant to 40 CFR § 60.250, the requirements of the New Source Performance Standards for Coal Preparation and Processing Plants (40 CFR Part 60, Subpart Y) are not applicable.

(j) Lime is considered a nonmetallic mineral as defined in 40 CFR § 60.671. The limestone handling system at this source commenced construction after August 31, 1983 and performs grinding operations. Therefore, pursuant to 40 CFR § 60.670, the limestone handling system at this source is subject to the requirements of the New Source Performance Standards (NSPS) for Nonmetallic Mineral Processing Plants (40 CFR Part 60, Subpart OOO). The affected facilities include each grinding mill, screening operation, belt conveyor, storage bin, and enclosed truck loading station associated with the limestone handling system.

Pursuant to 40 CFR § 60.672, the permittee shall comply with the following emission limitations:

(1) Emissions from any stack shall not exceed a PM limit of 0.05 g/dscm (0.022 gr/dscf) and an opacity limit of 7%.

(2) Fugitive emissions shall not exceed 10% opacity, except for crushers at which a capture system is not used.

(3) Fugitive emissions from crushers at which a capture system is not used shall not exceed 15% opacity.

(4) Truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of 40 CFR § 60.672.

(5) If an affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits specified above, or the building enclosing any affected facility shall not emit any fugitive emissions exceeding 7% opacity or any emissions from a vent exceeding a PM limit of 0.05 g/dscm (0.022 gr/dscf).

(6) Stack emissions from any baghouse that controls emissions from only an individual, enclosed storage bin shall not exceed 7 percent opacity.

The permittee shall also comply with the testing requirements in 40 CFR § 60.675 and the recordkeeping and reporting requirements in 40 CFR § 60.676.

(k) The emergency fire pump (NGS-120A) was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006. Therefore, this unit is subject to the requirements of the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII), pursuant to 40 CFR § 60.4200(a)(2)(ii). All other emergency generators

at this facility are not subject to these NSPS because they were either installed before April 1, 2006 or are not stationary units.

The emergency fire pump (NGS-120A) has a maximum capacity of 300 hp and was manufactured in 2010. The emissions from this unit shall comply with the following emission limits, pursuant to 40 CFR § 60.4205(c) and Table 4 of these NSPS:

(1) NMHC + NO_X emissions shall not exceed 4.0 g/KW-hr or 3.0 g/HP-hr.

(2) PM emissions shall not exceed 0.2 g/KW-hr or 0.15 g/HP-hr.

Engine NGS-120A has a displacement less than 9 liters per cylinder. Pursuant to 40 CFR § 60.4207(b), the permittee must use diesel fuel that meets the requirements of 40 CFR § 80.510(b) for nonroad diesel fuel (ultra low sulfur diesel fuel), except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

The permittee shall comply with the operating requirements specified 40 CFR § 60.4211(a) and the engine certification requirements in 40 CFR § 60.4211(c). There are no initial notification requirements for this emergency fire pump, pursuant to 40 CFR § 60.4214(b).

(l) The emergency generators and fire pumps at this source are considered stationary reciprocating internal combustion engines (RICE) and are subject to the NESHAP for Stationary Reciprocating Internal Combustion Engines (40 CFR Part 63, Subpart ZZZZ). Stationary diesel generators EG1, EG2, EG3, NPG-746, and NGS-120A are subject to this NESHAP. All the affected units are compression ignition engines (CI).

The applicable requirements for the affected units can be divided into the following three categories:

(1) Units with no specific requirements:

For the existing emergency generators with capacities greater than 500 hp (EG1), the permittee is not required to meet the requirements of this subpart and of 40 CFR 63, Subpart A, pursuant to 40 CFR § 63.6590(b)(3)(iv). No initial notification is required.

(2) Units with specific requirements:

For the existing emergency generators with capacities equal to or less than 500 hp (EG2, EG3, and NPG-746), the permittee shall comply with the following work practice requirements specified in Table 2c of this subpart, pursuant to 40 CFR § 63.6602:

(1) Change oil and filter every 500 hours or annually;

(2) Inspect air cleaner every 1,000 hours or annually;

(3) Inspect hoses and belts every 500 hours or annually; and

(4) Minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

The initial compliance date for units EG2, EG3, and NPG-746 is May 3, 2013, pursuant to 40 CFR § 63.6595(a).

(3) Units subjected to NSPS under 40 CFR Part 60, Subpart IIII:

The emergency fire pump (NGS-120A) is an emergency unit with a maximum capacity less than 500 hp and is subject to the requirements of NSPS for Stationary CI ICE, 40 CFR Part 60, Subpart IIII. For this unit, compliance with this NESHAP is demonstrated by complying with the requirements specified in the NSPS for Stationary CI ICE, 40 CFR Part 60, Subpart IIII, pursuant to 40 CFR § 63.6590(c).

The following table summarizes the capacity, construction date, unit category type, and applicable requirements for each emergency generator subject to 40 CFR Part 63, Subpart ZZZZ:

Unit ID	Max. Capacity (hp)	Construction Date	Unit Category	Subpart ZZZZ Requirements
EG1	515	before 12/19/2002	Existing RICE	None
EG2	280	before 06/12/2006	Existing RICE	Work Practice
EG3	70	before 06/12/2006	Existing RICE	Work Practice
NPG-746	469	before 06/12/2006	Existing RICE	Work Practice
NGS-120A	300	after 06/12/2006	New RICE	Compliance through compliance with 40 CFR Part 63, Subpart IIII

(m) Tank NGS-064-A is used to store gasoline. However, this tank commenced construction in 1991. Therefore, pursuant to 40 CFR § 60.110, the New Source Performance Standards for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978 (40 CFR Part 60, Subpart K) are not applicable.

(n) Tank NGS-064-A is used to store gasoline and commenced construction in 1991. However, the maximum capacity of this tank is less than 40,000 gallons. Therefore, pursuant to 40 CFR § 60.110a, the New Source Performance Standards for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or

Modification Commenced After May 19, 1978 and Prior to July 23, 1984 (40 CFR Part 60, Subpart Ka) are not applicable.

(o) The diesel storage tank NGS-075B has a maximum storage capacity greater than 75 cubic meters (19,813 gallons) and was constructed after July 23, 1984. Since the diesel fuel stored in this tank has a maximum true vapor pressure of less than 3.5 kPa, tank NGS-075B is exempt from the requirements of the New Source Performance Standards for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (40 CFR Part 60, Subpart Kb), pursuant to 40 CFR § 60.110b(b). Therefore, the requirements of this NSPS are not applicable.

(p) The parts washers at this source do not use halogenated HAP solvents. Therefore, pursuant to 40 CFR § 63,460(a), these units are not subject to the requirements of the NESHAP for Halogenated Solvent Cleaning (40 CFR Part 63, Subpart T).

(q) There are specific SO_2, NO_X, and CO emission limits (in lbs/MMBtu) for boilers U1 through U3. The FIP for this source (40 CFR § 49.5513) and the PSD Permit #AZ 08-01, issued on November 20, 2008, require the source to install and operate CEMS to ensure continuous compliance with the SO_2, NO_X, and CO emission limits. These requirements have been incorporated into this part 71 renewal permit. Therefore, the SO_2, NOx, and CO emissions from boilers U1 through U3 are exempt from the requirements of 40 CFR Part 64 (Compliance Assurance Monitoring (CAM)), pursuant to 40 CFR § 64.2(b)(1)(vi).

The FIP for this source (40 CFR § 49.5513) has specific PM emission limits for boilers U1 through U3 and the CAM requirements used to apply to these units. However, the permittee recently installed PM CEMS for each of the boilers U1, U2, and U3 to demonstrate compliance with the PM emission limits specified in NESHAP, Subpart UUUUU. Since the PM emission limit in this NESHAP is more stringent than the PM emission limits in FIP, compliance with the PM emission limit for NESHAP, Subpart UUUUU using the new PM CEMS is sufficient to demonstrate compliance with PM emission limit in FIP. Therefore, the PM emissions from boilers U1 through U3 are exempt from the CAM requirements, pursuant to 40 CFR § 64.2(b)(1)(vi). A permit condition (Condition II.M) has been added to this Part 71 permit renewal to require the operation of PM CEMS with the stacks associated with boilers U1, U2, and U3.

There are no specific PM/PM_{10} emission limitations for the coal handling operations or the ash handling operations. Therefore, pursuant to 40 CFR § 64.2(a), the requirements of 40 CFR Part 64 (CAM) are not applicable to these units.

The limestone handling operations at this source are subject to the PM emission limit in 40 CFR Part 60, Subpart OOO. The control devices associated with the limestone handling operations are baghouses DC-9, DC-10, and DC-11. The pre-control PTE of baghouse DC-9, DC-10, and DC-11 is each less than the major source threshold of 100

tons/yr. Therefore, pursuant to 40 CFR § 64.2(a), these baghouses are not subject to 40 CFR Part 64 (CAM).

(r) The permittee is subject to the requirements of the Asbestos NESHAP (40 CFR Part 61, Subpart M). The applicable requirements are specified in the permit document.

(s) The permittee is subject to the requirements of 40 CFR Part 82 (Protection of Stratospheric Ozone). The applicable requirements are specified in the permit document.

Summary of Applicable Federal Requirements

Federal Air Quality Requirement	Current or Future Requirement
Federal Implementation Plan for NGS (40 CFR § 49.5513)	Current
Acid Rain Regulations (40 CFR Parts 72-78)	Current
Visibility FIP (40 CFR § 52.145(d))	Current
NSPS for Nonmetallic Mineral Processing Plants (40 CFR Part 60, Subpart OOO)	Current
NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII)	Current
NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63, Subpart UUUUU)	Current
NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD)	Current
NESHAP for Stationary Reciprocating Internal Combustion Engines (40 CFR Part 63, Subpart ZZZZ)	Current
Asbestos NESHAP (40 CFR Part 61, Subpart M)	Current
Protection of Stratospheric Ozone (40 CFR Part 82)	Current
Regional Haze BART Requirements (40 CFR § 51.308)	Current (Included in the NGS FIP)

5. Additional Requirement

In order to demonstrate compliance with 40 CFR Part 60, Subpart OOO for the existing limestone handling system, a reopening permit was issued on November 13, 2003 and included the following testing, monitoring, and recordkeeping requirements for baghouses DC-9, DC-10, and DC-11, which are used to control the emissions from the limestone handling system:

(a) Stack testing for particulate matter emissions from the exhaust stacks of baghouses DC-9, DC-10, and DC-11 shall be conducted once every five (5) years using EPA Method 5 or Method 17. In addition, if during any twelve (12) consecutive month

period visible emissions are observed three times from any one baghouse, the permittee shall conduct a performance test on that baghouse within 120 days of the third observation.

(b) The permittee shall conduct a weekly visual emission survey of the exhaust stacks of baghouses DC-9, DC-10, and DC-11 while the equipment is operating and during daylight hours, by a person certified in EPA Method 9. If any visible emissions are observed, the permittee shall conduct an opacity test using EPA Method 9 within 24 hours while the equipment is operating in accordance with 40 CFR § 60.675.

(c) The permittee shall record and maintain the following records for each visible emission observation or Method 9 opacity test:

(1) the date and time of the observation and the name of the observer.

(2) the unit ID number.

(3) a statement of whether visible emissions were detected, and if so, whether they were observed continuously or intermittently.

(4) the results of the Method 9 test, if required.

6. Endangered Species Act

Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. § 1536, and its implementing regulations at 50 CFR Part 402, USEPA is required to ensure that any action authorized, funded, or carried out by USEPA is not likely to jeopardize the continued existence of any Federally-listed endangered species or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. NNEPA is issuing this federal Part 71 permit pursuant to a delegation from USEPA. However, this permit does not authorize the construction of new emission units or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations. Therefore, NNEPA and USEPA have concluded that the issuance of this permit will have no effect on listed species or their critical habitat.

7. Use of All Credible Evidence

Determinations of deviations from, continuous or intermittent compliance with, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit; other credible evidence (including any evidence admissible under the Federal Rules of Evidence) must be considered by the source, NNEPA, and U.S. EPA in such determinations.

8. **NNEPA Authority**

Authority to administer the Part 71 Permit Program was delegated to the Navajo Nation EPA by USEPA Region IX in part on October 13, 2004 and in whole on March 21, 2006. This permit is issued pursuant to the May 2005 Voluntary Compliance Agreement between the permittee and the Navajo Nation, which provided for Navajo regulation of NGS for CAA purposes. The permittee shall comply with the terms of this permit and shall be subject to enforcement of the permit by the Navajo Nation EPA and USEPA, pursuant to the terms of the Voluntary Compliance Agreement. The permittee's agreement to comply is effective upon the permittee's written acceptance of the permit and expires at the end of the permit term, unless the permit is renewed. The permittee's agreement to comply may be withdrawn during the permit term only if the Voluntary Compliance Agreement is terminated or expires as provided in that Agreement.

9. Public Participation

a. <u>Public Notice</u>

As required by NNOPR § 403(A), this permit renewal is being publicly noticed and made available for public comment. The content, methods, and timing of public notice are described in NNOPR § 403(B)-(D), and include a 30- day public comment period. *See also* 40 CFR § 71.11(d) (equivalent public notice and comment provisions).

Public notice of this proposed permit action will be provided by mailing a copy of the notice to the permittee, U.S. EPA Region 9, and the affected states (Utah and Arizona). A copy of the notice will also be provided to all persons who submit a written request to be included on the mailing list to the following individual:

Tennille Begay
Navajo Nation Operating Permit Program
P.O. Box 529
Fort Defiance, AZ 86504

E-mail: tbbegay@navajo-nsn.gov

Public notice will be published in a daily or weekly newspaper of general circulation in the area affected by this source.

b. <u>Opportunity for Comment</u>

Members of the public may review a copy of the draft permit prepared by NNEPA, this statement of basis for the draft permit, the application, and all supporting materials submitted by the source at:

Navajo Nation Air Quality Control Program
Route 112 North, Bldg No. F004-51

Fort Defiance, AZ 86504

Copies of the draft permit and this statement of basis can also be obtained free of charge from NNEPA's website:

www.navajonationepa.org/airqty/permits

or by contacting Tennille Begay at the NNAQCP address listed above or by telephone at (928) 729-4248. All documents will be available for review at the NNAQCP office indicated above during regular business hours.

If you have comments on the draft permit, you must submit them during the 30-day public comment period. All comments received during the public comment period and all comments made at any public hearing will be considered in arriving at a final decision on the permit. The final permit is a public record that can be obtained by request. A statement of reasons for any changes made to the draft permit and responses to comments received will be sent to persons who commented on the draft permit.

If you believe that any condition of the draft permit is inappropriate, you must raise all reasonably ascertainable issues and submit all arguments supporting your position by the end of the comment period. Any supporting documents must be included in full and may not be incorporated by reference, unless they are already part of the administrative record for this permit or consist of tribal, state or federal statutes or regulations or other generally available referenced materials.

Any comments on the acid rain permit shall be submitted to following individual at US EPA:

Geoffrey Glass (AIR-3)
EPA Region 9
75 Hawthorne Street
San Francisco, CA 94105

c. Opportunity to Request a Hearing

A person may submit a written request for a public hearing to Tennille Begay, at the address listed in Section 9(a) above, by stating the nature of the issues to be raised at the public hearing. Based on the number of hearing requests received, NNEPA will hold a public hearing whenever it finds there is a significant degree of public interest in a draft operating permit. If a public hearing is held, NNEPA will provide public notice of the hearing and any person may submit oral or written statements and data concerning the draft permit.

d. <u>Mailing List</u>

If you would like to be added to NNEPA's mailing list to be informed of future actions on this or other Clean Air Act permits issued on the Navajo Nation, please send your name and address to Tennille Begay at the address listed in Section 9(a) above.