DRAFT Statement of Basis - Narrative
NSR Permit

Company: El Paso Electric Company
Facility: Rio Grande Generating Station
Permit No(s): 1554M1
Tempo/IDEA ID No.: 122 - PRN201000001
Permit Writer: Cember Hardison

Fee Tracking

Tracking	**NSR tracking entries completed:** [x] Yes [] No
	NSR tracking page attached to front cover of permit folder: [x] Yes [] No
	Paid Invoice Attached: [] Yes [x] No
	Balance Due Invoice Attached: [x] Yes [] No
	Invoice Comments:

Permit Review	**Date to Enforcement:** 12-3-10	**Inspector Reviewing:** Judy Fisher
	Date Enf. Review Completed: 12-10-10	**Date of Reply:** 12-10-10
	Date to Applicant: 12-3-10	**Date of Reply:** 12-13-10
	Date of Comments from EPA: N/A	**Date to EPA:** N/A
	Date to Supervisor:	

1.0 **Plant Process Description:**

This facility is an electric power generating station located in Sunland Park, Doña Ana County, NM. El Paso Electric (EPE) currently uses three dry bottom, wall fired natural gas steam boilers, 6, 7, and 8, to run three turbine generators driven by high pressure, superheated steam. Total electric power production from the boilers is 288 MW gross, and 245 MW annual average. A natural gas fueled simple cycle GE Energy turbine proposed in this application would be used to generate 95.3 MW for a total annual average of 340.3 MW from the entire facility.

2.0 **Description of this Modification:**

Note: Effective January 1, 2011 the Environmental Protection Agency (EPA) implemented a regulation change that may cause this application to be subject to either Prevention of Significant Deterioration (PSD) permitting for TSP and PM2.5 or non-attainment permitting for PM10.

EPA changed the regulations to require that the condensable fraction of particulate matter (PM) emissions which include three sizes, TSP, PM10, and PM2.5, be included to determine if a PSD or non-attainment permit is required. For this facility, a PSD or non-attainment major modification happens when there is a <u>net</u> emissions increase that meets or exceeds the following significant emission levels: 100 tpy CO, 40 tpy NOx, 40 tpy VOCs, 25 tpy TSP, 15 tpy PM10, and 10 tpy PM2.5. El Paso Electric is currently working on a netting analysis and unless it shows that the "net" emissions increase of TSP, PM10, and PM2.5 are below the applicability thresholds stated above, the permit application will have to be denied since it was not submitted as a PSD or non-attainment application. If the permit application moves forward we will mail copies of El Paso's netting analysis to the 4 locations of application copies.

Permittee wants to construct a 95.3 MW natural gas fired simple cycle turbine used to generate electricity. The turbine would increase the annual average electric power production from 245 MW to a total annual average of 340.3 MW. This facility was constructed before 1972, before promulgation of the NSR regulation, and had not been modified until the addition of this turbine. Therefore, this is the first NSR permit for this facility. NSR conditions will apply only to the new equipment. Conditions to existing equipment will be applied through the Title V (TV) permit.

Facility modifications would include:
- Construct Unit GT-9, a 95.3 MW/142,576 hp natural gas fire simple cycle turbine, model GE LMS 100PA
- Install a selective catalytic reduction (SCR) system with associated ammonia system, ammonia tank, and fugitive ammonia emissions from the control device piping. The SCR will reduce turbine NOx emissions.
- Install an oxidation catalyst to reduce turbine CO and, at low loads, reduce VOC emissions
- Install Unit GC-9, a cooling tower for the new turbine
- Permit additional VOC fugitive emissions from fuel piping for the turbine, Unit FUG 9

Removal of Diesel Fuel:
The applicant is removing the option to use diesel fuel in the boilers which is currently allowed for a limited number of hours each year. Diesel has a higher total sulfur content than natural gas, so the allowable SOx emissions will be reduced.

Revisions to the Existing Units, boilers 6, 7, 8:
NOTE: The TV renewal application was submitted before this NSR application and includes the following revisions. The TV renewal permit may or may not be issued before this NSR permit. Therefore, the following summarizes the changes to the TV permit reported in the TV application and carried forward into this NSR application. There are no modifications as defined by 20.2.72.7.P NMAC to the existing units, only revisions to TV permitted limits.
- Removing 2nd and 3rd operating scenarios that allow diesel fuel with sulfur of 0.05% and 0.26% respectively.
- Boiler 8 - Adding a flue gas recirculation (FGR) control device to control NOx emissions from Boiler 8 to 20.2.33 NMAC emission limit of 0.30 lb/MMbtu.
- Boiler 8 - Increasing the NOx pound per hour emission limit from 403.4 to 460.5 pounds per hour (pph). The increase in pph emissions is not a modification since there is no increase in capacity and since the original emission limit was erroneously set at 403.4 pph but should have been 460.5 pph.
- Boilers 6, 7, & 8 - Increasing the 1-hr average pph CO emission limit (except unit 6) and removing the 3-hr average CO emission limit; and decreasing the CO ton per year (tpy) emission limit. Limiting short term emissions per hour, rather than over 3 hrs, is more

appropriate to demonstrate compliance with ambient standards. According to the applicant, increase in 1-hr CO emissions are due to the type of Continuous Emissions Monitoring (CEMs), which is a dilution-extractive CO CEMs that dilutes stack emissions with ambient air and not due to a modification. During winter months, the ambient CO increases due to the geography and weather patterns pulling in higher concentrations from increased open burning in Juarez. Additionally, the winter inversions keep the ambient CO from dispersing. (see applicant's email dated May 7, 2010 in TV application P127R2).

- Boiler 8 – Increasing the VOC tpy and PM10 pph and tpy emission limits. Limits are only changing due to changing the method of estimating these emissions.

Incorporating requirements of Consent Decree D-101-CV-2008-02777 Filed 7-31-09
From Section V.21. of Consent Decree (decree applies only to boilers 6, 7, & 8):
a. Annual tuning of the 3 boilers (6, 7, & 8) at the Rio Grande Generating Station as required by paragraph 1 (See specific tuning requirements in paragraph 1. Paragraph 1 also requires reporting average NOx (0.30 lb/MMbtu, hourly 3-hr rolling ave) and CO (pph, ave of CEMs data per hr) emissions before and after tuning;
b. Operation and maintenance of the Flue Gas Recirculation (FGR) system at the Unit 8 boiler, provided the FGR system is installed on unit 8 in accordance with paragraph 11 (FGR was approved and operating in July 8, 2010);
c. An averaging time [rolling ave.] of 3 hours for the 0.3 pound per million BTU maximum emission rate for NO2 set forth in Condition 3.1 of the existing operating Permit as provided in Paragraph 19; and
d. A precision of 2 significant figures for the 0.3 (0.30) pound per million BTU maximum emission rate for NO2 set forth in Condition 3.1 of the existing operating permit.
Paragraph I of the Consent Decree also requires:
I.B.3. Proper and efficient calibration of CEMs including installation of software so that the calibration periods are clearly indicated in data recorded by the system.
I.C.4. Using actual sulfur content data [in fuel], in accordance with 40 CFR 75, Appendix D, to calculate SO2 emissions for each unit (boiler).

EMISSIONS ESTIMATES & COMPLIANCE

<u>Boilers</u>
Boiler NOx pound per hour (pph) and ton per year (tpy) emission limits were determined by converting the limit of 0.30 lb/MMbtu (20.2.33 NMAC limit) using their respective heat rate capacities (MMBtu/hr). Boiler 8 pph emissions used 0.30 lb/MMbtu x 1535 MMBtu/hr and ton per year (tpy) NOx emissions used 0.257 lb/MMbtu x 1345 annual average MMBtu/hr. Permittee must keep the boiler 8 heat rate capacity to 1535 MMbtu/hr maximum and 1345 MMbtu/hr annual average. If boiler 8 is operated at a higher heat rate capacity resulting in an increase in emissions, the change in operations must be permitted and would be considered a modification under NSR rules.

Boiler CO pph emission limits were determined using historical continuous emissions monitoring system (CEMS) data and tpy CO emissions were determined with EPA's AP42 1.4-1.

Boiler CO and NOx Compliance: Permittee will conduct initial compliance tests and use CEMS to monitor NOx, CO, and CO2 from the boilers. 40 CFR 75 requires CEMs for NOx & CO2. Permittee must demonstrate compliance with both the lb/hr and tpy NOx and CO limits using the CEMs hourly emission data and actual number of hours operated over 12 months. NOx and CO start up and shut down emissions have historically been included in the facility emission limits.

Boiler PM and VOC Emission Limits & Compliance: Emissions were determined with EPA's current AP42 1.4-2. Applicant used Total PM emission factor (EF) from AP42 1.4-2 and set TSP = PM10 = PM2.5. Per AP42 1.4-2 footnote C, total, condensable, and filterable PM is considered to be <= PM10. VOC emissions were also determined using AP42 1.4-2. Compliance with the VOC & PM emission limits will be demonstrated through compliance with the NOx and CO emission limits.

Boiler SO2 Emission Limits & Compliance: SO2 emission limits for boilers were determined using the gas analysis sulfur detection limit of 0.03 gr/100 scf plus a safety factor of 1.5 for pph emissions and 1.25 for tpy emissions. Natural gas analyses show non-detectible sulfur, so a safety factor was added to account for possible fluctuation. Permittee will show compliance with SO2 emission limits by limiting total sulfur content in the fuel to 0.045 gr/100 scf of gas annually.

Boiler HAPs emissions were determined using California's AB2588 emission factors except for Hexane which used data from the Houston and Lighting Power Test report dated May 27, 1994. This test report is available on the EPA website nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=9100EWMJ.txt or can be found by searching EPA's National Service Center for Environmental Publications (NSCEP) website http://www.epa.gov/nscep/index.html. Boilers are not major for any HAPs and therefore, no maximum achievable control technologies (MACTS) in 40 CFR 63 apply.

Turbine

Turbine NOx, CO, VOC, TSP, PM10, and PM2.5 emission limits are based upon manufacturer data. The manufacturer provided data for 20 operating conditions that varied ambient temperatures and load. Pound per hour (pph) worst case manufacturer data were used which resulted under the low operating temperatures at 100% load scenario. The ton per year (tpy) emissions were based upon average ambient temperature at 100% load. 100% load showed worst case emissions at average ambient temperature.

Turbine Emissions Controls:

- NOx emissions are to be reduced using a selective catalytic reduction (SCR) system. The SCR will use a homogenous vanadia-titania base metal catalyst plus an ammonia (NH3) reductant (19% aqueous NH3) to convert NOx into nitrogen gas (N2) and water with about an 88.8% average control efficiency. The SCR system will emit NH3, called ammonia slip.
- CO emissions and VOC emissions at low loads are to be reduced with catalytic oxidization (called COR system by GE) made of precious metals with about a 77.5% control efficiency. Per GE, excess O2 in the flue gas and the catalyst are used to convert VOCs and CO to CO2 and water.

- Control of the SCR/COR systems will be by a programmable logic control (PLC) system.
- GE warrantees the SCR and COR catalysts for up to 3 years of operation based on 8760 hrs/yr, 26,280 total hours, or 3.25 years after catalyst delivery which ever comes first.

Turbine Start up and Shut Down NOx & CO:
From start up, until emissions compliance occurs takes no longer than 30 minutes. From time zero minutes (T0) to time ten minutes (T10) there is zero NOx control and from T10 to T29 there is an aggregate 50% NOx control. The selective catalytic reduction (SCR) system catalyst must be heated to 500-540 deg F before achieving permissive to inject ammonia into vaporizer, ammonia piping and AIG must be packed, then ammonia flow trimmed. This all takes 20 to 25 minutes. From T0 to T10 there is zero CO control and full CO control from 10 minutes on. CO catalytic oxidizer begins operating at ~500 deg F and is in full operation above 700 deg F. Manufacturer data showed VOC start up and shut down emissions equivalent to steady state VOC emissions. The CO and NOx pph emission limits reported in Table 2-E of the application include emissions during start up and shut down.

NOx Start Up Emissions determined as follows:
- 3.01 pounds NOx 7 minutes, per manufacturer start up data
- 15.03 pounds NOx 20 minutes rest of start up cycle. Used manufacturer worst case uncontrolled NOx w/ 44% control (81.07pph x (1-0.44) x (20 min/60 min))
- 4.9 pounds NOx 27 minutes steady state. Used manufacturer worst case controlled NOx emissions for 33 minutes (8.92 pph x 33min/60min).
- Total start up NOx for 1 hour: 3.01 + 15.03 + 4.9 = **22.9 pph NOx**

NOx Shut Down emissions:
- 0.44 pounds NOx 10 minutes. 3.97 pph manufacturer shut down data (3.97 pph x (100-88.8% control).

CO Start up Emissions determined as follows:
- 10.21 pounds CO for 7 minutes, per manufacturer start up data
- 7.56 pounds CO for 20 minutes remaining start up cycle. Used manufacturer worst case controlled CO emissions (22.69 pph x 20min/60min)
- 12.5 pounds CO for 33 minutes steady state. Used manufacturer worst case controlled CO emissions for rest of hour (22.68pph x 33 min/60 min)
- Total start up CO for 1 hour: 10.21 + 7.56 + 12.5 = **30.2 pph CO**

CO Shut Down emissions:
2.97 pounds CO 10 minutes. 13.21 pph x (100-77.5% control)

Annual NOx and CO Start up and Shut down Fraction:
Applicant requested one start up/shut down per day plus one additional per week for a total of 417 start up/shut downs per year. Actual operations may not require this many start ups.
- NOx Annual SU/SD: (18.04 lbs SU + 0.44 lbs SD) x 1ton/2000lb x 417 times/yr = 3.85 tons/yr
- CO Annual SU/SD: (17.77 lbs SU + 2.97 lb SD) x 1ton/2000lb x 417 times/yr = 4.33 tons/yr

Turbine NOx & CO compliance with both steady state and start up and shut down emissions will be shown using continuous emissions monitoring system (CEMs), initial EPA Method compliance tests, and periodic Relative Accuracy Test Audit (RATA) tests required by Acid Rain regulations (40 CFR 75).

Turbine VOC compliance will be shown by demonstrating compliance with NOx and CO limits.

Turbine NH3 emissions (ammonia slip) & compliance: Ammonia emissions from the turbine's SCR are based upon manufacturer emissions data. Excess ammonia slip can occur when catalyst temperatures are not optimum for chemical reaction and/or too much ammonia is injected. Therefore, compliance with NH3 pph and tpy emission limits will be met by operating the SCR system with optimal temperatures and ammonia injection according to manufacturer recommendations and monitored & recorded using the SCR/COR programmable logic control system (PLC).

Turbine PM Emissions (see GE document dated 5-28-10): GE Energy guaranteed total PM10 emissions to 5.9 lb/hr (5.5 pph from turbine + 0.4 pph from SCR & Cat Oxidizer). GE PM10 emissions assume a sulfur content of no more than 0.25 gr/100 scf in fuel and at 50% to 100% of steady state loads. Filterable PM10 are 2.1 pph and condensable are 3.8 pph. El Paso Electric must follow GE Guidelines for PM10 Guarantee & Testing. Manufacturer provided emissions data for only PM10. Permittee set emissions limits for TSP & PM2.5 equal to PM10 as they are required to report and model all 3 fractions. When asked for clarification if fractions less than or greater than PM10 exist the applicant stated it was their understanding that total particulate (PM10 and PM2.5, etc) numbers are all the same and all particulate matter is considered less than PM2.5. Finally, the vendor did not have speciation between the two sizes.

Turbine TSP, PM10, and PM2.5 compliance:

- EPA Method 5 stack test required to measure filterable TSP emissions within 60 days after achieving maximum production rate or no later than 180 days after source startup (if source does not achieve max production rate).
- Newly promulgated EPA Method 201A (PM2.5&PM10 fraction) & 202 (condensable) stack tests required to measure PM10 and PM2.5 filterable and condensable fractions.
- 202 & 201A tests required within 60 days after achieving maximum production rate or no later than 180 days after source start up (if max production rate not achieved). If the final revised test methods (proposed revisions dated March 25, 2009 EPA-HQ-OAR-2008-0348) are not promulgated when the turbine reaches maximum production rate, the timeline will start from the promulgation date of the revised test methods.

Turbine SO2 emissions & compliance: SO2 emissions were determined using the gas analysis fuel sulfur detection limit plus a safety factor of 1.5 for pph emissions and 1.25 for tpy emissions. Natural gas analyses typically show non-detectible sulfur, therefore, the safety factor was added to account for possible fluctuations. <u>However, GE Energy guaranteed total PM10 emissions</u> of 5.9 lb/hr (5.5 pph from turbine + 0.4 pph from SCR & Cat Oxidizer) <u>based on a sulfur content of no more than 0.25 gr/100</u> scf in fuel. <u>Therefore, fuel sulfur must be limited to the lower rate of 0.25 gr/100</u> scf rather than 0.45 gr/100 scf annual average.

Turbine HAPs emissions were determined using EPA's AP42 3.1-3. No individual HAP or the sum of HAPs are major, therefore, no MACTs from 40 CFR 63 are required.

All cooling tower Particulate Matter (PM) emissions (boilers and turbine) were determined using EPA's AP42 13.4 for TSP and the Frisbee Paper for PM10 and PM2.5. Chlorine is added as a biocide to the cooling towers and results in a HAP byproduct, hydrochloric acid (HCl). HCl emissions from the boiler & turbine cooling towers are insignificant. The permit will include operating conditions for the cooling towers, such as monitoring water circulation rate (gpm) and water TDS (ppmw) to ensure that PM emission limits are met. Permittee will be required to report manufacturer data supporting the parameters used to calculate emissions for the turbine cooling tower once installed

3.0 Source Determination:

1. The emission sources evaluated by the applicant are the sources listed in regulated equipment Table 2-A and exempt equipment Table 2-B.

2. Single Source Analysis: Do surrounding or associated sources belong to the same industrial grouping (i.e., same two-digit SIC code grouping, or support activity)? **No. EPE did not indicate that there are any surrounding or associated sources.**
   A. Common Ownership or Control: Are the surrounding or associated facilities under common ownership or control? **No**
   B. Contiguous or Adjacent: Are the surrounding or associated facilities located on one or more contiguous or adjacent properties? **No**

3. Is the source, as described in the application, the entire source for 20.2.70, 20.2.72, or 20.2.74 NMAC applicability purposes? **Yes**

4.0 PSD Applicability – This Section Revised 1-13-11

A. The source an existing PSD Major Source that has never undergone a PSD review.

B. The project emissions for this modification ~~are not significant~~ are significant as of January 1, 2011 unless El Paso Electric can show the "net" emissions increase of TSP, PM10, and PM2.5 are below significance levels.

Pollutant	Emission increase (tpy)	Significance Level (tpy)
NOx	39.1	40.0
CO	94.1	100.0
VOC	9.2	40.0
SOx	0.36	40.0
TSP filterable + condensable [1]	10.6 + 16.6 = 27.2	25.0
PM10 filterable + condensable [1]	9.3 + 16.6 = 25.9	15.0
PM2.5 filterable + condensable [1]	9.2 + 16.6 = 25.8	10 [2]

1. From FR Vol. 73, NO. 96, May 16, 2008, page 28334 - Prevention of Significant Deterioration and NA NSR permits issued after the effective date of this NSR implementation rule but before the end of EPA's transition period for the NSR program are not required to account for condensable emissions in PM2.5 or PM10 emissions limits. After January 1, 2011 (or any earlier date established in the upcoming rulemaking codifying test methods) EPA will require that NSR permitees include limits of condensable emissions, as appropriate. Note: Rule may not become effective until after incorporation into AQB's SIP.

EPA established the transition period to among other items, allow time to promulgate revised EPA test methods for condensable PM (Test 202) and fine particulate matter (PM2.5) (Test 201A).

AQB requires permittees to include the condensable fraction (if estimation method is available) to be reported and included in air dispersion modeling to demonstrate compliance with standards, but follows EPA's transition criteria to exclude condensables in NSR applicability.

2. Since a PM2.5 significance level has not yet been incorporated into SIP approved 20.2.74 NMAC, AQB uses the PM2.5 significance level of 10 tpy which is the significance level in 40 CFR 51.166.

C. Netting is ~~not~~ required since the project emissions are ~~not~~ significant.

D. BACT will be required for this modification if it is found to be a major modification.

5.0 **History (In descending chronological order, showing NSR and TV):** *The asterisk denotes the current active NSR and Title V permits that have not been superseded.

Permit Number	Issue Date	Action Type	Description of Action (Changes)
*1554-M1	Current Action	NSR Permit, minor 20.2.72	First NSR permit issued. Facility was constructed before 1972, before promulgation of the NSR regulation, and had not been modified until the addition of this turbine. Therefore, this is the first NSR permit for this facility. **Facility modifications include:** Construct Unit GT-9, a 95.3 MW/142,576 hp natural gas fire simple cycle turbine, model GE LMS 100PA; add a cooling tower (unit CT-9) and selective catalytic reduction (SCR) system with associated ammonia system, ammonia tank, and fugitive ammonia emissions from the control device piping. Turbine CO and VOC emissions will also be controlled with an oxidation catalyst. VOC fugitive emissions will also be added from fuel piping for the turbine, Unit FUG 9 **NOx 3129.9 tpy, CO 1108.0 tpy, VOC 78.7 tpy, SOx 1.6 tpy, TSP 197.4 tpy, PM10 122.6 tpy, PM2.5 117.7 tpy.** **TSP filterable 112.0 tpy, condensable 85.4; PM10 filterable 37.2 tpy, condensable 85.4 tpy; PM2.5 filterable 32.2 tpy, condensable 85.4.**
*P127-A-R2	Pending	Acid Rain Renewal	Acid Rain Renewal. No modifications.
*P127-R2	Pending	TV Renewal	**Revisions to the TV permit:** Remove 2nd and 3rd operating scenarios that allow diesel fuel with sulfur of 0.05% and 0.26% respectively; add flue gas recirculation (FGR) control device to control NOx emissions from Boiler 8 to demonstrate compliance with 20.2.33 NMAC emission limit of 0.30 lb/MMbtu; increase NOx pound per hour emission limit from 403.4 to 460.5 pph (department determined increase in pph emissions is not a modification - see Note about "modifications" for Boilers 6, 7, and 8 in P127R2 SOB); incorporate requirements of Consent Decree D-101-CV-2008-02777 Filed 7-31-09 **NOx 3090.75 tpy, CO 1013.9 tpy, VOC 69.43 tpy, SOx 1.3 tpy, TSP 170.3 tpy, PM10 96.74 tpy, PM2.5 91.83 tpy.**

Permit Number	Issue Date	Action Type	Description of Action (Changes)
D-101 CV-2008-02777	7-31-09	Consent Decree	Consent Decree D-101 CV-2008-02777 for NOV ELP-0122-0501 for violating CO, NOx, and SO2 emissions limits. Applies to boilers 6, 7, and 8. Corrective Actions: tune each boiler at the Rio Grande Generating Station annually; report performance of tuning and the before and after tuning NOx lb/MMbtu and CO pph emissions; conduct CEMs calibrations, install software that records the calibrations, and submit verification of such in 30 days; monitor sulfur dioxide using actual sulfur content data in accordance with 40 CFR 75, Appendix D to calculate SO2 emissions and notify of such within 30 days; install flue gas recirculation (FGR) on boiler 8 (EPN-1). Implementation of Permit Conditions: maximum allowable NO2 emission rate (20.2.33 NMAC 0.3 lb/MMbtu) for each boiler 6, 7, & 8 shall be interpreted as having an averaging time of 3 hours and shall be interpreted as having 2 significant figures (0.30 lb/MMbtu – vs – 0.3 lb/MMbtu). Integration with Permit - submit application in 180 days to incorporate the following conditions: annual tuning of 3 boilers as required by section 1 of consent decree; operation and maintenance of boiler 8 (EPN-1) FGR; state maximum NO2 emission limit of 0.3 lb/MMbtu (20.2.33 NMAC) using 2 significant figures 0.30 lb/MMbtu and determined with a 3 hr-averaging time.
P127R1M1	6-6-08	TV administrative Revision	Change responsible official to Mr. Andres Ramirez.
P127-A-R1	9-22-05	TV Renewal	Issued 5 year T-IV permit for Boiler Units 6, 7, and 8 with 40 CFR 72.9(c)(1) allowances and ORIS code 2444. NOx limitations in 40 CFR 76 are only applicable to coal-fired units and thus do not apply to this facility.
P127R1	9-22-05	TV Renewal	Scenario 1 (natural gas): **NOx 3342.4 tpy, CO 3504.0 tpy, VOC 19.8 tpy, SOx 29.1 tpy, PM10 8.7 tpy, Chlorine 4.1 tpy, formaldehyde 1.1 tpy, and hexane 19.9 tpy.** Scenario 2/3 (diesel): NOx 3343.2 tpy, CO 3777.8 tpy, VOC 21.6 tpy, SOx 227.4 tpy, PM10 17.8 tpy, Chlorine 4.1 tpy. Permitted Units 6, 7, and 8. Number 2 diesel fuel is available for backup fuel in the event of a gas supply curtailment. The permit places restrictions on unit 8 limiting the output to 145 Megawatts average output. This permit is a renewal of the P127M1.
P127M1-Rev	8-31-05	TV Revision	Scenario 1 (natural gas): **NOx 3343.7 tpy, CO 3504.0 tpy, VOC 60.4 tpy, SOx 6.7 tpy, TSP 83.4 tpy, Chlorine 4.1 tpy.** Scenario 2 (diesel): NOx 3376.2 tpy, CO 3536.9 tpy, VOC 61.1 tpy, SOx 546.8 tpy, TSP 135.7 tpy, Chlorine 4.1 tpy. A permit reopening to adjust emission limits to more accurately reflect the potential to emit for the 2 operating scenarios.

Permit Number	Issue Date	Action Type	Description of Action (Changes)
P127M1	6-16-03	TV reopening	Scenario 1: **NOx 3343.7 tpy, CO 3504.0 tpy, SOx 6.7 tpy, TSP 83.4 tpy, VOC 60.4 tpy, and Chlorine 4.1 tpy.** Scenario 2: NOx 3376.8 tpy, CO 3536.9 tpy, SOx 546.8 tpy, TSP 135.7 tpy, VOC 61.1 tpy, and Chlorine 4.1 tpy. Adjust emissions limits to "more accurately reflect" the potential to emit for the 2 operating scenarios. Permitted Units 6, 7, and 8.
P127	1-27-00	New TV	NSR and PSD "Grandfathered" Facility. **Both scenarios: NOx 3,672.9 tpy, CO 21,900.0, SOx 651.8 tpy, TSP 107.9 tpy, VOC 23.0 tpy, and Chlorine 4.1 tpy.** Permitted Units 6, 7, and 8, Babcock and Wilcox boilers that can use either natural gas or diesel as fuel. This facility is an electric power generation station operated by three dry bottom, wall-fired gas steam boilers. There are three turbine generator units driven by high pressure, superheated steam. Total electric power production of the facility from these three generators is **288 MW gross, and 261 MW net.** The primary fuel used at this facility is pipeline quality natural gas. Number 2 diesel oil is available for use as a back-up fuel in the event of gas supply curtailment.
1554	5-28-98	New NSR permit - denied	NSR permit application closed/denied effective 5-28-98. NSR permit application submitted 6-94 to install lo-NOx burners on Unit 8 to meet state limit of 0.3 lb/MMBtu. Unit 8 has always had to run at reduced capacity to meet state emission regulation for gas fired equipment. Application ruled complete 5-28-97 and denied effective 5-28-98.
P127A	12-12-97	New Acid Rain Permit	Effective 1-1-00 to 12-31-04. Permitted Units 6, 7, and 8 with SO2 allowances.
No permit number	4-21-97	Letter of understanding	Letter of understanding between NMED and El Paso Electric Company to install low-NOx burners and **reduce capacity to 145 MW** on unit 8 to meet NOx emissions limit of 0.30 lb/MMBtu and comply with 20.2.33 NMAC. Installation of LNB and operating at reduced firing rate would "result in a net decrease in emissions of NO2 and CO and would not result in an increase in other air contaminants". It was understood that since the LNB and reduced firing rate would result in a decrease in emissions, that this modification to unit 8 would be exempt from 20.2.72. Permittee was to submit monthly reports of weekly averages of hourly NO2 emissions and corresponding MW output to NMED until permittee obtained an air permit for Unit 8 under 20.2.72 or 20.2.70.

6.0 Public Response/Concerns:

In addition to the applicant's public notice requirements in 20.2.72 NMAC, the application sent 172 public notice letters to Sunland Park citizens and government authorities on a list from the Camino Real Landfill hearing. No response from any of the applicant's public notice was received.

In addition to AQB's public notice requirements, the AQB contacted a Sunland Park citizen by phone, sent 172 public notice letters in Spanish and English to Sunland Park citizens and government officials, sent 116 notices of a community meeting using an updated address list of Sunland Park citizens and government officials, and held a community meeting on September 25, 2010 in Sunland Park. About 17 adults and 6 children attended the community meeting.

Based upon the public response received as of November 29, 2010, the AQB recommended to the Department Secretary that no hearing be held.

Between December 8 and 12, 2010, three additional letters and 62 signatures requesting a hearing were received after the hearing recommendation. AQB has since recommended a hearing with agreement of the Division Director. Therefore, if the permit application moves forward, a hearing will be held.

Verification of Applicant's Required Public Notice – the applicant has met all regulatory notification requirements as follows:
NOTE: Per New Mexico State's Office of General Council March 2002 interpretation, when a municipality, Indian Tribe, or county is located outside of New Mexico, public notification is not required if outside of the state boundaries. This legal interpretation would also apply to property owned outside of New Mexico.
20.2.72.203.B(1)(a) Notified by certified mail all property owners found on the Doña Ana County property assessment records that are located within 100 feet of the facility's property boundary. Rio Grande Generating Station is located in Sunland Park city limits and has a population of more than 2500 persons.
20.2.72.203.B(2) Notified, by certified mail, municipalities, Counties, and Tribes located within 10 miles of the facility. The only County, New Mexico Municipalities, and Tribes within 10 miles are, Doña Ana County and Sunland Park. All other New Mexico communities, such as Santa Teresa and Canutillo, are either not incorporated municipalities, are greater than 10 miles from the property boundary, are located in the State of Texas, or are located in the Country of Mexico.
20.2.72.203.B(3) Published once in a newspaper of general circulation in the [New Mexico] county where the facility is located and should appear in the legal or classified section and in one other location of the newspaper to provide the most effective notice. Applicant published two English language ads in the El Paso Times and two Spanish language ads in the El Diario de El Paso.
20.2.72.203.B(4) The applicant certified that public notice was posted on June 15, 2010 at four publically accessible locations near the source including the facility entrance at Rio Grande Power Station Entrance, Sunland Park Community Library, Sunland Park City Hall, and US Post Office at 3500 McNutt Rd.
20.2.72.203.B(5) The applicant provided an email of the public service announcement request submitted to KGRT, a radio station in Las Cruces. The public notice content shown in the email met the requirements of 20.2.72.203.D.

AQB Public Notice:
20.2.72.206.A(7) Mailed a copy of AQB's public notice on October 7, 2010 to the State of Texas since it is within 50 km of the facility.
20.2.72.206.A(3) Published both an English language and Spanish language public notice in the Las Cruces Sun News on October 10, 2010. The permit writer verified with the Las Cruces Sun News that there were subscribers and newspaper stands in Sunland Park. At the 9-25-10 community meeting, the permit writer stated the PN would probably be published in the El Paso Times, but AQB does not have a purchase order for El Paso Times so had to use the Las Cruces Sun News.
20.2.72.206.A(4) Public notice was sent to individuals maintained on the department's list of individuals and organizations who have indicated in writing they would like to be notified of all permit applications.

7.0 <u>Compliance Testing:</u>

Unit No.	Compliance Tests Already Completed	Test Dates
Boilers 6, 7, 8	Relative Accuracy Testing Audit (RATA) Tests for NOx and CO2 CEMs as Required by 40 CFR 75,	8-13-09

	Appendix B Reference Methods found 40 CFR 75.22 Quality Assurance And Control Procedures 40 CFR 75.21	
Boilers 6, 7, 8	SO2 RATA or QA/QC per 40 CFR 75.11(d)(2)	8-13-09
Boilers 6, 7, 8	CO CEMs QA/QC Test with EPA Methods 10 and Flov Rate Methods 1 to 4	8-13-09
Unit No.	**Compliance Tests to be Required**	**Test Dates**
Boilers 6, 7, 8 & Turbine GT-9	Relative Accuracy Testing Audit (RATA) Tests for NOx and CO2 CEMS as Required by 40 CFR 75, Appendix B & NSPS KKKK Reference Methods found 40 CFR 75.22 Quality Assurance And Control Procedures 40 CFR 75.21	Initial certification within 60 days of achieving max production rate or within 180 days of start up if max production rate not achieved within 120 days. At least Semiannually thereafter. Frequency may be reduced to annually based upon results of accuracy but never more than 8 calendar quarters apart. (Frequency in App B of Part 75, 2.3.1.1 and Figs 1 & 2)
Boilers 6, 7, 8 & Turbine GT-9	SO2 RATA or QA/QC per 40 CFR 75.11(d)(2)	Per 75.11(d)(2)
Boilers 6, 7, 8 & Turbine GT-9	Initial CO CEMS certification using 40 CFR 60, Appendix B and CO CEMS QA/QC (periodic Cylinder Gas Audits (CGAs)) using 40 CFR 60, Appendix F	Initial certification within 60 days of achieving max production rate or within 180 days of start up if max production rate not achieved within 120 days. CO CGA periodic testing to be performed in conjunction with NOx RATA testing in accordance with 40 CFR 75
Turbine GT-9	NOx (Method 7E) and CO (Method 10) Initial compliance Tests	Within 60 days of achieving max production rate or within 180 days of start up if max production rate not achieved within 120 days.
Turbine GT-9	TSP (Method 5) & PM10 and PM2.5 fractions, both Filterable and Condensable (Proposed Revised Methods 201A & 202)	Within 60 days of achieving max production rate or within 180 days of start up if max production rate not achieved within 120 days. If revised 201A and 202 test

		methods are not yet promulgated when maximum production rate achieved or 180 days have past from start up, time line starts from the promulgation date of the final revised test methods.
Turbine GT-9	NOx method test per 40 CFR 60.4400, Subpart KKKK requirements.	Per 40 CFR 60.4400(a) and 40 CFR 60.8: conduct initial performance tests and subsequent tests on an annual basis, no more than 14 calendar months following the previous test. Per 60.440(b)(5) the CEM performance evaluation (RATA) may be conducted as part of the initial performance test.

8.0 Startup and Shutdown:

A. If applicable, did the applicant indicate that a startup, shutdown, and emergency operational plan was developed in accordance with 20.2.70.300.D(5)(g) NMAC? **Yes**

B. If applicable, did the applicant indicate that a malfunction, startup, or shutdown operational plan was developed in accordance with 20.2.72.203.A.5 NMAC? Not applicable. **Yes**

C. Did the applicant indicate that a startup, shutdown, and scheduled maintenance plan was developed and implemented in accordance with 20.2.7.14.A and B NMAC? **Yes**

D. Were emissions from startup, shutdown, and scheduled maintenance operations calculated and included in the emission tables? **Yes.** Start up and shut down emissions are included in the emission limits in Table 2-E for the boilers and turbine.

9.0 Modeling:

El Paso Electric's modeling shows that ambient air quality standards for NOx, CO, TSP, PM10, PM2.5, and SO2 will be met. Ambient impacts of ammonia emissions (NH3) are less than $1/100^{th}$ of the occupational exposure limit (OEL) in 20.2.72.502 NMAC. NH3 is a New Mexico TAP and if modeling shows that the 8-hour average ambient concentration of the toxic air pollutant exceeds $1/100^{th}$ of its OEL, a health assessment is required. For NH3 the OEL is $18mg/m^3$ and so 1/100 of the OEL is $0.18mg/m^3$. The maximum impact of NH3 emissions from Rio Grande Generating Facility is 0.0286 mg/m^3.

El Paso Electric modeled NOx, CO, TSP, PM10, PM2.5, and NH3 emissions. AQB determined that modeling SO2 emissions was not required to show compliance with SO2 standards as these emissions are less than 1 pph and were previously modeled at a much higher emission rate. Modeling included emissions from surrounding stationary sources in NM and Texas within 65 km of the facility and included background concentrations for NO2, CO, TSP, PM10, and PM2.5 for Doña Ana County.

The Air Quality Bureau will conduct its own modeling review to determine ambient air quality standards for NOx, CO, TSP, PM10, PM2.5, and SO2 will be met and to determine if NH3 emission impacts are below the screening level of $1/100^{th}$ of the OEL.

10.0 <u>State Regulatory Analysis Applicable to both NSR Only and TV Only Units (NMAC/AQCR):</u>

<table>
<tr><th>20 NMAC</th><th>Title</th><th>Applies (Y/N)</th><th>Comments</th></tr>
<tr><td>2.1</td><td>General Provisions</td><td>Y</td><td>The facility is subject to Title 20 Environmental Protection Chapter 2 Air Quality of the New Mexico Administrative Code so is subject to Part 1 General Provisions, specifically 20.2.1.116 Significant Figures.</td></tr>
<tr><td>2.3</td><td>Ambient Air Quality Standards</td><td>Y</td><td>Facility must demonstrate compliance with state ambient air quality standards according to 20.2.70.D(3).</td></tr>
<tr><td>2.7</td><td>Excess Emissions</td><td>Y</td><td>Applies to all facility sources</td></tr>
<tr><td>2.18</td><td>Oil Burning Equipment – Particulate Matter</td><td>N</td><td>Boilers 6 and 8 may no longer combust diesel fuel, therefore, this regulation no longer applies. The permittee withdrew the diesel fuel option on May 7, 2010.</td></tr>
<tr><td>2.33</td><td>Gas Burning [external combustion] Equipment - Nitrogen Dioxide</td><td>Y</td><td>Boilers 6, 7 and 8</td></tr>
<tr><td colspan="4">6/EPN-3, 610 MMBtu/hr, constructed 1-1-1957
7/EPN-2, 590 MMbtu/hr, constructed 1-1-1958
8/EPN-1, 1570 MMBtu/hr, constructed 1-10-1968
20.2.33.7.A. Existing (construction commenced or modification commenced before 2-17-72)
Per applicant none of the units have been modified since construction and are defined as existing units.
20.2.33.108.B limits NO2 emissions per unit to =< 0.30 lb/MMbtu of heat input from <u>existing</u> gas burning units with a heat input greater than 1,000,000 million British Thermal Units per year per unit.
Compliance Demonstration: The permittee will demonstrate compliance with 20.2.33.108.B through NOx CEMs required by 40 CFR 75.
Note: Permittee calculated their pph and tpy NOx emissions by converting from 0.30 lb/MMbtu except for boiler 8 where they used 0.257 MMbtu/hr to calculate tpy. Permittee indicated that CEMs data shows that <u>average</u> heat rate capacity of boiler 8 over a year's time is 0.257 lb/MMbtu. Permittee must also demonstrate compliance with the pph and tpy limits using CEMs data.</td></tr>
<tr><td>2.34</td><td>Oil Burning Equipment - Nitrogen Dioxide</td><td>N</td><td>Boiler 8 may no longer combust diesel fuel, therefore, this regulation no longer applies. The permittee withdrew the diesel fuel option on May 7, 2010.</td></tr>
<tr><td colspan="4">Boiler 8 was allowed to use diesel fuel up to 720 hr/yr (1570 MMBtu/hr x 720 hr/yr = 1,130,400 MMBtu/yr), so therefore, was subject to 20.2.34, but is no longer.
Boiler 6 was also allowed to burn diesel but <u>was not subject</u> because it was permitted to burn diesel for 876 hr/yr thereby limiting the annual heat input below the applicability threshold of 1,000,000 MMbtu/yr (610 MMbtu/hr x 876 hr/yr = 534,360 MMbtu/yr). Boiler 6 would have to burn diesel up to 1639.3 hrs/yr to be subject.</td></tr>
</table>

20 NMAC	Title	Applies (Y/N)	Comments
2.61	Smoke and Visible Emissions	Y	**Boilers 6, 7, 8, and turbine GT-9** **20.2.61.109 limits opacity** from emissions stacks to 20%. **20.2.61.114 Opacity is determined** using 40 CFR 60, Appendix A Method 9 for a minimum of 10 minutes.
2.70	Operating Permits	Y	PTE is > 100 TPY. Source is TV major for NOx, CO, TSP, PM10, and PM2.5 as defined at 20.2.70.200 NMAC.
2.71	Operating Permit Fees	Y	Source is subject to 20.2.70 NMAC as cited at 20.2.71.109 NMAC.
2.72	Construction Permits	Y	20.2.72.200.A(2) NMAC
2.73	NOI & Emissions Inventory Requirements	Y	Applicable to all facilities that require an NSR and/or a TV permit.
2.74	Permits-Prevention of Significant Deterioration	TBD	TSP and PM2.5 project emissions from addition of new turbine, cooling tower, and ancillary equipment are significant as of January 1, 2011 (20.2.74.502 NMAC) due to a rule change requiring inclusion of condensable PM. PM10 project emissions are also significant, but this would be subject to non-attainment permitting. The applicant is working on a netting analysis to determine if the "net" emissions increase is significant. According to the applicant, all units, before addition of turbine GT-9, were constructed before and have not been modified since the effective date of this NMAC (7-20-95) and the 1977 CAA Amendments when PSD was first implemented (40 CFR 52.21, 6-19-78). Source is listed in Table 1 of 20.2.74.501 and is a major source as defined in 20.2.74.7.AF(1) but has never undergone a PSD review. Any major modifications to this facility (as defined in 20.2.74.7.AD) will be subject to PSD review.
2.75	Construction Permit Fees	Y	Facility is subject to 20.2.72 NMAC so is subject to permit fees. Since it is a TV source, is not subject to NSR annual fees in accordance with 20.2.75.11.E an annual NSR enforcement and compliance fee shall not apply to sources subject to 20.2.71 NMAC.
2.77	New Source Performance	Y	Applies to any stationary source constructing or modifying and which is subject to the requirements of 40 CFR Part 60, as amended through December 31, 2009.
2.78	Emissions Standards for HAPs,	N	This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 61.
2.79	Permits – Nonattainment Areas	TBD	As of January 1, 2011, PM10 project emissions are significant. The source affects the City of El Paso, TX PM10 non-attainment area.

<table>
<tr><th>20 NMAC</th><th>Title</th><th>Applies (Y/N)</th><th>Comments</th></tr>
<tr><td colspan="4">Ozone Sunland Park: The facility is located in the Sunland Park ozone maintenance area which is not designated as an ozone non-attainment area. AQB Non-attainment Link.
In March 2008 the ozone NAAQS was lowered from 0.08 ppm to 0.075 ppm so on 3-11-09, AQB submitted a recommendation to EPA to designate Sunland Park, NM (including the communities of Santa Teresa and La Union) non-attainment for the 8-hr ozone standard. EPA postponed designation.
On January 6, 2010, EPA recommended a more stringent 8-hr primary ozone standard of 0.060 – 0.070 ppm and a cumulative secondary standard of 7-15 ppm-hrs. EPA planned to finalize ozone NAAQS by the end of August, 2010. However, EPA postponed finalizing the air quality standards for Ozone to end of December, 2010.
Per EPA, finalizing the ozone standard is postponed to July 2011.</td></tr>
<tr><td colspan="4">PM10 Moderate Non-Attainment Area in Anthony, New Mexico: Rio Grande Generating Station is not located in the Anthony area PM10 non-attainment area and ambient impacts do not affect this area, therefore this non-attainment area does not apply.</td></tr>
<tr><td colspan="4">PM10 Moderate Non-Attainment Area in El Paso County, El Paso City, TX: As of January 1, 2011 PM10 project emissions are major since EPA promulgated a rule change that requires inclusion of condensable PM. Project PM10 emissions are 25.8 tpy which are greater than the significance level of 15 tpy in 20.2.79.7.AM(1). Since project emissions are now significant, this will be a major modification unless the applicant can show the "net" emissions increase is not major per NSR non-attainment rules (20.2.79.7.U NMAC). Rio Grande Generating Station is not located in El Paso City's PM10 non-attainment area, but the PM10 radius of impact of 3.2 km exceed those in 20.2.79.119.A and would impact the City of El Paso PM10 non-attainment area if this was a major modification (20.2.79.109.A(2)).</td></tr>
<tr><td>2.80</td><td>Stack Heights</td><td>N</td><td>Boiler stacks were in existence before 1970, but air dispersion techniques were not used for basis of an emission limit. All stacks are currently less than 65 m (387.14ft) which is less than good engineering stack height allowed by 40 CFR 51.100(ii)(1).</td></tr>
<tr><td>2.82</td><td>MACT Standards for Source Categories of HAPs.</td><td>N</td><td>This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 63. This facility is not a major HAP source and as of April 30, 2010, there are not are source GACTs that apply.</td></tr>
</table>

20 NMAC	Title	Applies (Y/N)	Comments
2.84	Acid Rain Permits	Y	**Boilers 6, 7, 8 and turbine GT-9.** This facility is subject to Title IV of the federal act and federal acid rain permitting requirements adopted here by reference. **20.2.84.8 ADOPTION BY REFERENCE OF FEDERAL ACID RAIN PERMITTING REQUIREMENTS:** Except as otherwise provided in 20.2.84.10 NMAC, the portions of the federal acid rain program promulgated by the United States environmental protection agency under 40 CFR Part 72 (including all portions of Parts 73, 74, 75, 77 and 78 referenced therein) and 76, and amended in the federal register through May 18, 2005, to implement Sections 407 (nitrogen oxides emission reduction program), 408 (permits and compliance plans) and 412 (monitoring, reporting and recordkeeping requirements) of the federal act, are hereby incorporated into this part. **20.2.84.10 MODIFICATIONS AND EXCEPTIONS:** The following modifications or exceptions are made to the incorporated federal rules: **A.** for purposes of this part, the term **"permitting authority" shall mean the department**; and **B.** requirements imposed on affected sources under the federal Act shall not be subject to NMSA 1978, Section 74-2-8 [Variances].
2.85	Mercury Emission Standards and Compliance Schedules for Electric Generating Units	N	This applies to electric power generation units that combust coal or coal-derived fuel. This facility does not combust coal or coal-derived fuel.
2.86	Best Available Control Technology for Mercury At New Power Plants	N	This facility does not combust coal or coal-derived fuel. The part applies to all coal-fired power plants within the jurisdiction of the environmental improvement board, except for coal-fired power plants constructed and generating electric power and energy before July 1, 2007.
2.87	Greenhouse Gas Emissions (GHG) Reporting	N/A	**Regulation repealed November 10, 2010 and replaced with 20.2.300 Reporting of Greenhouse Gas Emissions NMAC. Change effective January 1, 2010. 20.2.300 does not yet include the most recent amendments to the federal rule.** **Under old 20.2.87: Boilers 6, 7, 8** emissions were previously reported. Permittee was required to determine if any trivial, insignificant activities, or any other sources may be subject to 20.2.87 2009 and 2010 GHG reporting years as the reporting requirements changed for the second (2009), third (2010) years.

20 NMAC	Title	Applies (Y/N)	Comments
2.300	Reporting of Greenhouse Gas Emissions – Effective Jan 1, 2011	Y	**Boilers 6, 7, 8, and Turbine GT-9 are subject** as electricity generation sources as defined by incorporated reference at 40 CFR 98.2(a)(1), Table A-3 and 98.40(a). First reporting will be for 2011 emissions: reports due by April 1 2012. 10,000 metric tons CO2e or more in combined emissions from all applicable source categories. (20.2.300.101.A & B) **"20.2.300.100 ADOPTION OF 40 CFR PART 98:** Except as otherwise provided, the following subparts of 40 CFR Part 98, as amended in the federal register through October 28, 2010 (75 FR 66434), are hereby incorporated by reference. **A.** 40 CFR Part 98 Subpart A - General Provisions, which includes Sections 98.1 through 98.8 and Tables A-1 through A-5 of Subpart A. **C.** 40 CFR Part 98 Subpart D - Electricity Generation, which includes Sections 98.40 through 98.48." 20.2.300 does not incorporate 40 CFR 98 Mandatory Greenhouse Gas Reporting rule into the NM State SIP, but references citations from 40 CFR 98 with revisions to create AQB's greenhouse gas reporting rule 20.2.300 NMAC. 40 CFR 98 is a stand alone rule, therefore facilities may be subject to both 20.2.300 and 40 CFR 98.
2.89	Qualified Generating Facility Certification	N	This facility does not meet the definition of a qualified generating facility.

11.0 Federal Regulatory Analysis For both NSR Only and TV Only Units:

Air Programs Subchapter C (40 CFR 50)	National Primary and Secondary Ambient Air Quality Standards	Applies (Y/N)	Comments
C	Federal Ambient Air Quality Standards	Y	Defined as applicable at 20.2.70.7.E.11, Any national ambient air quality standard.

NSPS Subpart (40 CFR 60)	Title	Applies (Y/N)	Comments
A	General Provisions	N	Applies if any other subpart applies.
40 CFR Part 60, Appendix B	Performance Specification 4, 4A, or 4B, Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources	N/A	**CO CEMS Turbine GT-9:** The permittee is not subject to this part due to a federal NSPS, but uses this procedure to audit the CO CEMS.
Specifications 4, 4A, and 4B are for evaluating the acceptability of carbon monoxide (CO) continuous			

<table>
<tr><th>NSPS Subpart (40 CFR 60)</th><th>Title</th><th>Applies (Y/N)</th><th>Comments</th></tr>
<tr><td colspan="4">emission monitoring systems (CEMS) at the time of installation or soon after.

Permittee will need to determine the applicable performance specification for the GT-9 CO CEMS:
Performance Specification 4—Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources
Performance Specification 4A—Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources
Performance Specification 4B—Specifications and Test Procedures for Carbon Monoxide and Oxygen Continuous Monitoring Systems in Stationary Sources</td></tr>
<tr><td>40 CFR 60, Appendix F</td><td>Quality Assurance Procedures for CEMS</td><td>N/A</td><td>CO CEMS Turbine GT-9: The permittee is not subject to this part due to a federal NSPS, but uses this procedure to audit the CO CEMS.</td></tr>
<tr><td colspan="4">1.1 Applicability. Procedure 1 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by any continuous emission monitoring system (CEMS) that is used for determining compliance with the emission standards on a continuous basis as specified in the applicable regulation. The CEMS may include pollutant (e.g., $S0_2$and $N0_x$) and diluent (e.g., 0_2or $C0_2$) monitors.</td></tr>
<tr><td>40 CFR 60, Subpart D</td><td><u>Subpart D--STANDARDS OF PERFORMANCE FOR FOSSIL-FUEL-FIRED STEAM GENERATORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 17, 1971</u></td><td>N</td><td>Per Applicant:
EPN-3/boiler 6 constructed 1-1-57
EPN-2/boiler 7 constructed 1-1-58
EPN-1/boiler 8 constructed 1-10-68
Per applicant, no units have been reconstructed or modified as defined.
All units were constructed before 1971</td></tr>
<tr><td>40 CFR60.40a, Subpart Da</td><td>Performance Standards for Electric Utility Steam Generating Units, for which construction commenced after 9-18-78.</td><td>N</td><td>All units constructed before 1978
Per applicant no units have been reconstructed or modified.</td></tr>
<tr><td>40CFR60.40b, Subpart Db</td><td>Electric Utility Steam Generating Units (after 6-19-84)</td><td>N</td><td>All units constructed before 1984.
Per applicant no boilers have been reconstructed or modified.</td></tr>
<tr><td>40 CFR 60.40c, Subpart Dc</td><td><u>PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES</u>
<u>Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</u></td><td>N</td><td>Applies to units with less than maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less. Each of these units has a capacity greater than that.</td></tr>
<tr><td>40 CFR 60, Subpart KKKK</td><td><u>Subpart KKKK--STANDARDS OF PERFORMANCE FOR STATIONARY COMBUSTION TURBINES</u></td><td>Y</td><td>Turbine GT-9.</td></tr>
</table>

NSPS Subpart (40 CFR 60)	Title	Applies (Y/N)	Comments
60.4305(a) applies to stationary combustion turbines with a heat input greater than 10 MMBtu/hr at HHV. Emissions data show GT-9 has a heat rate capacity between 782.5 to 888.1 MMBtu/hr HHV at 100% load. **64.4320(a) Table 1 – NOx** emission standard is 15 ppm at 15% O2 or 54 ng/j of useful output (0.43 lb/MWh) since emissions data shows capacity of turbine is > 850 MMBtu/hr and the unit is a new turbine firing natural gas. Manufacturer guarantees after control NOx to 2.8 ppmvd @ 15% O2 site conditions. **60.4330 (a) SO2 emission limit** (1) =< 110 ng/J or 0.90 lb/MWh gross output or (2) may not burn fuel containing total potential sulfur emissions in excess of 26 ng SO2/J or 0.060 lb SO2/MMBtu of heat input. **60.4335** NOx Compliance with water/steam injection – does not apply. Not used as a control device but for power augmentation. **60.4340(b) NOx monitoring** uses CEMs for NOx so are subject to (b) (1) CEMs as in 60.4335(b) and 60.4345 **60.4365(a) SOx monitoring is exempt** since the permittee can provide a contract for fuel showing the total sulfur content in the natural gas is less than 20 gr/100 scf. **60.4375 Reporting** requirements as they apply **60.4400 Initial Performance Test (a)** must conduct initial test per 60.8 and subsequent tests on an annual basis, no more than 14 calendar months following the previous test. **(b)(5)** If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit. **60.4405** specifies the performance test requirements if a NOx diluent CEMS is used.			

NESHAP Subpart (40 CFR 61)	Title	Applies (Y/N)	Comments
A	General Provisions	N	Applies if any other subpart applies.

MACT Subpart (40 CFR 63)	Title	Applies (Y/N)	Comments
A	General Provisions	N	Applies if any other subpart applies.
40 CFR 63 Subpart H	Subpart H--NATIONAL EMISSION STANDARDS FOR ORGANIC HAZARDOUS AIR POLLUTANTS FOR EQUIPMENT LEAKS	N	F-2 fugitive emissions from natural gas piping. According to fuel analysis, natural gas contains less than 5% organic HAPs. (63.160(a) and definition of "in organic hap service" in 63.161)
40 CFR 63 Subpart Q	Subpart Q—National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	N	Applicant states that they do not use chromium based water treatment chemicals in their cooling towers. Cooling tower water is treated with chlorine (Cl_2). 63.400(a) The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources as defined in §63.401.
40 CFR 63 Subpart YYYY	Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for	N	Facility is not a major source of HAPs.

MACT Subpart (40 CFR 63)	Title	Applies (Y/N)	Comments
	Stationary Combustion Turbines		
Proposed NESHAP	Emission standards for Area Source Industrial Commercial & Institutional Boilers: Proposed Rule 4-30-10	N according to 4-30-10 Proposed Rule	**Link to 4-30-10 FACT Sheet** **Link to 4-30-10 Proposed Rule** The facility no longer combusts diesel fuel as a back up fuel, therefore, it is not subject to the new rule as proposed on 4-30-10. Proposed area source NESHAP applies to large or small boilers that combust coal, oil, or biomass boilers. Area source boilers operating with natural gas are not subject to the proposed NESHAP dated 4-30-10.
Proposed NESHAP	Emission Standards for Major Source Industrial, Commercial, and Institutional Boilers & Process Heaters: Proposed Rule 4-30-10	N according to 4-30-10 Proposed rule	Link to 4-30-10 FACT Sheet Link to 4-30-10 Proposed Rule The facility is not a major HAP source, therefore, it is not subject to the rule as proposed on 4-30-10. The proposed major source NESHAP applies to large and small boilers at major HAP sources that combust natural gas, fuel oil, coal, biomass, refinery gas or other gas to produce steam. The proposed rule also applies to process heaters.
40 CFR 63 Subpart DDDDD	Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters	N	This is not a major HAP source and according to 63.7491(c) **Boilers 6, 7, and 8** are exempt from this vacated MACT.
The facility is exempt from the vacated MACT since they consist of electric utility steam generating units. Also, the NESHAP applies to major HAP sources only. EPA has completed promulgation of NESHAP for all listed categories in 2005 (per EPA fact sheet Proposed Amendments Outlining Requirements for States to Set Case-by-Case Emission Standards When NESHAP are Not in Place (CAA Section 112(J) Rule) on TTN OAR website 2-17-10). Therefore, the facility is not subject to Case-by-Case MACT per 112(J) (listed source with no MACT promulgated or vacated) or to Case-by-Case MACT per 112(g) (Major HAP source not on list but with no EPA MACT).			

MACT Subpart (40 CFR 63)	Title	Applies (Y/N)	Comments
From DDDDD: **§ 63.7485** You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, **or is part of, a major source of HAP** as defined in §63.2 or §63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491. **§ 63.7491 Are any boilers or process heaters not subject to this subpart?** The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart. (c) An electric utility steam generating unit (including a unit covered by 40 CFR part 60, subpart Da) or a Mercury (Hg) Budget unit covered by 40 CFR part 60, subpart HHHH. **This rule was vacated by United States District of Columbia court of appeals on June 8, 2007.**			

Miscellaneous	Title	Applies (Y/N)	Comments
40 CFR 64	Compliance Assurance Monitoring	N	
NOx and CO emissions are monitored with CEMs. The current TV permit will require CEMs to monitor emissions from boilers and the turbine. Per 64.2(b)(vi) an emission limitation or standard for which a Part 70 or 71 permit specifies a continuous compliance determination method, as defined in 64.1, are exempt from CAM. *Continuous compliance determination method* means a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit. No other uncontrolled emissions from any unit are major.			
40 CFR 68	Chemical Accident Prevention	N	Applies to owners or operators of stationary sources with more than a threshold quantity of a regulated substance. According to the applicant, the amount of chlorine stored on site (150 lb cylinders used as a biocide in the cooling towers) does note exceed the threshold quantity of 2,500 lbs listed on Table 1 in 68.130 (List of Regulated Toxic Substances and Threshold Quantities for Accidental Release Prevention). 40 CFR 68 applies only when the aqueous ammonia concentration is 20% or more. The aqueous ammonia used for the SCR is 19% aqueous ammonia. Sulfuric acid was not found on Table 1. Sulfuric acid is used to regulate the pH of the cooling tower water.
40 CFR 70	Title V- State Operating	N	Not applicable – New Mexico State has

Miscellaneous	Title	Applies (Y/N)	Comments
	Permit Programs		full SIP approved authority and Title V is administered under 20.2.70 NMAC.
40 CFR 72	Title IV – Acid Rain Program	Y	**Boilers 6, 7, and 8 and turbine GT-9 are subject.** [AQB is the permitting authority and EPA is the administrator] **Note:** Acid Rain program identifies units as boilers 6, 7, and 8 and not by EPN-1, 2, and 3. **Turbine GT-9** will be a new unit per 72.6(a)(3)(i). **Note: The permittee is removing the option to operate with diesel fuel. The facility will only operate using natural gas.**

72.6(a) Applicability Boilers 6, 7, and 8 are "existing utility units" (72.2 definitions) and listed in Table 2 – Phase II Allowance Allocations in Subpart 73.10 and are not exempt per 72.6(b). 72.6(a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program: (2) A unit that is listed in table 2 or 3 of §73.10 of this chapter and any other existing utility unit, except a unit under paragraph (b) of this section.
Upon application submittal, permittee certified that they hold SO2 allowances in accordance with 72.9(c)(1).
72.2 Definitions.
Acid Rain Program means the national sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established in accordance with title IV of the Act, this part, and parts 73, 74, 75, 76, 77, and 78 of this chapter.
Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.
Permitting authority means either:
(1) When the Administrator is responsible for administering Acid Rain permits under subpart G [phase II implementation] of this part, the Administrator or a delegatee agency authorized by the Administrator; or
(2) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to administer Acid Rain permits under subpart G of this part and part 70 of this chapter.

40 CFR 73	Title IV – Acid Rain Sulfur Dioxide Allowance Emissions	Y	**Boilers 6, 7, and 8 are subject** [EPA is the administrator]

73.2(a) applies to owners, operators, & designated representatives of affected sources subject to 72.6.
73.1 Scope: 40 CFR 73 establishes requirements and procedures for allocating sulfur dioxide allowances and their tracking, holding, transferring, offsetting, selling, and other requirements.
Phase II SO2 allowances are found in 73.10 (b) Table II: Phase II allowances (2) The Administrator will allocate allowances to the compliance account for each source that includes a unit listed in table 2 of this section in the amount specified in table 2 column F to be held for the years 2010 and each year thereafter.

40 CFR 75	Title IV – Acid Rain Continuous Emissions Monitoring	Y	**Boilers 6, 7, and 8 and Turbine GT-9** Applicant defines, boilers as a gas-fired non-peaking units so Part 75 only requires SO2, NOx, and CO2 emissions monitoring. Although NOx emission reduction (Part 76) is not required for gas-fired units, NOx monitoring is still

Miscellaneous	Title	Applies (Y/N)	Comments
			required in Part 75. Gas-fired units are exempt from opacity monitoring (75.14(c)). Since coal is not used as fuel and units are not subject to a State or Federal Hg mass emissions reduction program, Hg monitoring is not required (75.80(a) & (1)).

72.2 Gas-fired means: (2) For purposes of part 75 of this chapter, the combustion of:
(i) Natural gas or other gaseous fuel (including coal-derived gaseous fuel) for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years….; and **(ii)** Fuel oil, for the remaining heat input, if any. **– the permittee is no longer using diesel fuel as a fuel option.**
Gaseous fuel means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat.
75.1 Purpose (a) establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO2), nitrogen oxides (NOX), and carbon dioxide (CO2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program…..
75.2 Applicability (a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO2 or NOX.
75.5 Prohibitions(e) No owner/operator shall disrupt CEMS or other approved emission monitoring avoiding monitoring and recording emissions except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed per 75.21 and appendix B.
75.10 General operating requirements (a)(1) determine SO2 emissions (see 75.11 Appendix D); **(2)** determine NOx emissions with CEMS **(3)** determine CO2 emissions – 3 options, see below.
SO2 Monitoring
75.11(d)(2) Specific Provisions for Monitoring SO2 Emissions – Permittee monitors SO2 according to Part 75 Appendix D since the units qualify as a gas-fired as defined in 72.2 of this chapter.
Appendix D - Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units
1.2 Initial Certification and Recertification requirements in 75.20 (g) must be completed to certify use of the optional SO2 emissions data protocol in Appendix D –includes meeting applicable general operating requirements of 75.10, requirements of appendix D, and initial certification or recertification requirements in 75.20.
2.1 to 2.1.7.5 Fuel Flowmeter Measurements
For each hour when the unit is combusting fuel, measure and record the flow rate of fuel combusted by the unit, except as provided in section 2.1.4 of this appendix. Measure the flow rate of fuel with an in-line fuel flowmeter, and automatically record the data with a data acquisition and handling system, except as provided in section 2.1.4 of this appendix.
2.2 to 2.2.8 Oil Sampling and Analysis – permittee is longer using diesel fuel as a fuel option. Perform sampling and analysis of oil to determine the following fuel properties for each type of oil combusted by a unit: percentage of sulfur by weight in the oil; gross calorific value (GCV) of the oil; and, if necessary, the density of the oil.
2.3 to 2.3.7 SO2Emissions From Combustion of Gaseous Fuels: (a) Account for the hourly SO2 mass emissions due to combustion of gaseous fuels for each hour when gaseous fuels are combusted by the unit using the procedures in this section.
NOx Monitoring
75.10(a)(2)- Owner/operator must measure both NO & NO2 with a NOx-diluent CEMs system with NOx pollutant concentration monitor, O2 or CO2 diluent gas monitor, and with an automated DAHS to measure

Miscellaneous	Title	Applies (Y/N)	Comments
and record NOx **in ppm**, O2 or CO2 in percent, **and** NOx emission rate **in lb/MMbtu**. **75.12** are the specific provisions for monitoring NOX emission rate. **CO2 monitoring** **75.10(a)(i)** Permittee measures CO2 emissions using the first of 3 options which requires a CO2 CEMs and flow monitoring system with an automated DAHS to measure and record CO2 concentration in ppm, volumetric gas flow in scfh, and CO2 mass emissions in tons/hr. **Note: 75.10(d)(1)** CEMs must be capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner/operator shall reduce all emissions & volumetric flow data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. **Consent decree requires 20.2.33 NOx lb/MMbtu boiler 6, 7, & 8 emissions be limited as 3-hr averages rather than 1-hour ave (requested by El Paso Electric), 40 CFR 75 requires NOx lb/MMbtu emissions be reported as hourly averages, and maximum lb/hr (not 3-hr ave) emission limits are required to demonstrate compliance with ambient standards. El Paso Electric calculated the lb/hr emissions for the boilers used in modeling by converting from 0.30 lb/MMbtu. Permit writer verified with Robert Samaniego Feb 2010, that due to the requirements of the consent decree, the permit must include the 3-hr average NOx emission limit (lb/MMbtu) for boilers 6, 7, and 8. Since a 1-hour NOx emission limit (lb/hr) is also required, the permit will have two short term NOx limits, 1-hr and 3-hr for boilers 6, 7, and 8.**			
40 CFR 76	Title IV – Acid Rain Nitrogen Oxides Emission Reduction Program	N	Title IV NOx emission reduction program applies to coal-fired units. This facility does not combust coal, but combusts natural gas.
40 CFR 77	Title IV – Acid Rain Offset Plans for Excess Emissions SO2	Y	**Applies to boilers 6, 7, & 8 and turbine GT-9. Currently, the boilers 6, 7, and 8 have SO2 Phase II Allowance.** [EPA is the administrator] (a) *Applicability.* The owners and operators of any affected source that has excess emissions of sulfur dioxide in any calendar year shall be liable to offset the amount of such excess emissions by an equal amount of allowances from the source's compliance account.
Title VI – 40 CFR 82	Protection of Stratospheric Ozone	N	According to the applicant, the facility does not "service", "maintain" or "repair" class I or class II appliances nor "disposes" of the appliances.
40 CFR 98	<u>PART 98--MANDATORY GREENHOUSE GAS REPORTING</u>	Y	**Boilers 6, 7, 8, and turbine GT-9** are subject. (40 CFR 98.2(a)(1)). EPA, not AQB, is the administrator of this regulation.
Boilers 6, 7, 8, and turbine GT-9 are subject per **98.40(a), Subpart D** electricity generating units subject to the requirements of the Acid rain Program and any others that are required to monitor and report EPA CO2 emissions year round according to 40 CFR 75. **GHGs to Report 98.42 (a)** must report the annual mass emissions of CO2, N2O, and CH4			

Miscellaneous	Title	Applies (Y/N)	Comments
98.47 Records Retention: Comply with the recordkeeping requirements of §98.3(g) and 98.37 [98.37 applies to Subpart C General Stationary Fuel Combustion Sources] **98.3 subject to (a) through (i) General monitoring, reporting, recordkeeping and verification requirements: (b)** The annual GHG report must be submitted no later than March 31 of each year for GHG emissions in the previous calendar year. **(1)** existing facilities – to be revised **(3)** facilities that become subject due to a physical or operational changes after 1-1-10, report emissions for first calendar year in which the changes occur. **(g) Recordkeeping:** Keep records for at least 3 years in an electronic or hard-copy format and make available to EPA upon request. **§98.9 See Table A-1** in Subpart 98.9 for global warming potentials and speciation of GHGs.			

12.0 **Exempt and/or Insignificant Equipment:**

NSR Exempt Activities or Equipment:
Exempt activities per 20.2.72.202 NMAC apply only to equipment or activities associated with new units GT-9, CT-9, FUG-9, and AST-9).

INSIGNIFICANT ACTIVITIES	JUSTIFICATION	Records Required ?
Maintenance: paints and coatings used for buildings; plant cleaning with solvents and chemicals; electrical maintenance using solvents.	20.2.72.202.A(1) activities for maintenance of grounds or buildings. This is not required to be reported in application but applicant reported anyway.	No
Emergency Generator	20.2.72.202 (B)(3) Standby generator (a) operated only during unavoidable loss of commercial utility power; and (b) operated less than 500 hrs/yr.	Yes, 20.2.72.202.B(3)(c)(ii). Permittee must maintain records of operation to show generator is not operated more than 500 hrs/yr.
Painting/Surface Coating of Equipment	20.2.72.202.B(6) includes spray painting, roll coating, and painting with aerosol spray cans if VOCs do not exceed 10 pph; and facility-wide total VOC content of all coating and clean-up solvent is less than 2 tpy.	Yes 20.2.72.202(B)(6)(c) permittee must keep sufficient records to verify that the requirements are met.

13.0 **New/Modified/Unique Conditions** (Format: Condition#: Explanation):

NOTE: Units installed before 1972 (boilers, their cooling towers, and their fugitive emissions) are not subject to the NSR regulation 20.2.72 as these units were installed before promulgation of the regulation. Total facility emissions Table 102.A & B and the equipment list in Condition A104 includes all facility units, including units not subject to 20.2.72 NMAC (NSR). The rest of the permit applies only to units subject to 20.2.72 NMAC (turbine, its cooling tower, and its fugitive emissions).

All Conditions are NEW –

Tables 102A and 102B – These are emissions from the entire facility, including boilers not subject to the permit.

Table 103A Applicable Requirements – Requirements applicable to units subject to NSR.

A104.B – The applicant requested 45 days from source start up, rather than 15 days from source installation, to submit the TBD values in Table 104.A. Permit writer verified with enforcement that extending the deadline submit TBD values should not cause enforcement issues due to the source type (not portable or allowed to replace units). Except for submitting the serial numbers of the new units, the permittee is still required to meet the 15 day requirement in Condition B110 since the other deadlines are required by 20.2.72.212 NMAC.

Table 105 Control Equipment – Controls subject only to NSR units.

A106 Allowable Emissions – Includes emission limits applicable only to unit subject to NSR.

A106.C – Changed NSPS KKKK sulfur requirements from a specific lb/MMBtu to just referencing the sulfur limits in 40 CFR 60.3440(a). The reference to the lb/MMBtu limit confuses the issue with general condition B112.C especially since the permittee will most likely meet the sulfur monitoring exemption in NSPS KKKK since the fuel sulfur content is so low.

A108.A - Compliance with Ton Per Year Emissions – Turbine and cooling tower may operate during any hour of the day, however, operating at 8760 hrs/yr would put emissions over the allowable tpy limits. Therefore, the permittee must track ton per month and ton per year emissions to stay in compliance with emission limits.

A115.A – Revisions to general conditions B111(7) and (8) requiring sampling lines be installed. Applicant requested that these conditions be deleted since sampling lines require maintenance and due to other issues and it would be unlikely that the department would ever use them for a facility with periodic emissions testing and CEMS. Permit writer verified with enforcement section that the sampling lines are typically used for portable analyzers so would never be required for this facility. Therefore, conditions B111(7) and (8) were revised to require the sampling lines only if requested by the department and within 30 days of request.

A401B – Turbine CO and VOC Control device: Operational requirements of the oxidation catalyst to reduce turbine CO and VOC emissions. The oxidation catalyst is not fully functional at operating temperatures lower than 700 deg F which takes up to 10 minutes. The permittee calculated emissions assuming that CO and VOC emissions are not reduced with the oxidation catalyst for the first 7 minutes. Therefore, the condition states that the oxidation catalyst does not need to be reducing CO and VOC emissions the first 7 minutes after startup of the turbine. These additional uncontrolled emissions are included in the pph emission limit in Table 106.

A401C – Turbine NOx Control – Operational requirements for SCR and meeting NH_3 emissions (ammonia slip). Anhydrous ammonia is more toxic than aqueous ammonia, and aqueous ammonia at a concentration of 20% or more is subject to 40 CFR 68, therefore, there are limits on the type and concentration of ammonia to that reported in the application.

The SCR is not fully functional at operating temperatures lower than 500-540 deg F which takes up to 30 minutes. The permittee calculated emissions assuming that NOx emissions are not reduced with the SCR for the first 30 minutes. Therefore, the condition states that the SCR does not need to be reducing NOx emissions the first 30 minutes after startup of the turbine. These additional uncontrolled emissions are included in the pph emission limit in Table 106.

A401D – NOx and CO CEMS – Title IV Acid Rain requires NOx and CO2 be monitored with CEMS. There are no requirements for monitoring CO with a CEMS, but that is the method chosen by the applicant. Also, the CO CEMS is not subject to 40 CFR 60, appendices B and F however, those are the procedures the permittee agreed to use for certification and QA/QC. The permit has emission limits for NOx and CO but not CO2, therefore, the permitted CEMS operating and certification requirements do not apply to the CO2 CEMS which is regulated by Acid Rain.

A401E – Acid Rain Fuel Monitoring is not necessary to show compliance with emission limits in this permit, but is a requirement of Title IV Acid Rain so is referenced here.

A401F – The fuel sulfur limit (0.25 gr/100scf) is based upon the manufacturer's PM10 guaranteed emission rate and is lower than that used to calculate SO2 emissions (0.45 gr/100scf annual average). The PM10 and PM2.5 pm emission limits are close to the PSD significance levels and therefore, the permittee should operate the unit in accordance with manufacturer guaranteed emission rates.

A401G – NOx and CO EPA initial method tests are typically required for new units. The timing of the initial tests are written to align with the time requirements of the NOx CEMS initial certification required by 40 CFR 75. PM10 and PM2.5 emission rates are close to PSD significance levels, therefore, testing is required. Also, the manufacturer did not speciate the various PM fractions. The PM fraction test method (201A) and PM condensable method (202) are currently being revised by EPA to correct deficiencies. Compliance demonstration will be more meaningful if completed with the revised test methods. Therefore, the tests will be completed with the revised methods once they are finally promulgated, even if testing must be delayed past the time requirements in Condition B111.A(2).

A401H – 20.2.61 – Brings forth requirements of state opacity requirements in 20.2.61 NMAC for combustion sources.

A401I – NSPS KKKK – Turbine GT-9 is subject to NSPS KKKK. The manufacturers guaranteed ppmvd limit is 2.75 which is much lower than NSPS KKKK emission standard. Permittee will use the NOx CEMS to show compliance and will be exempt from on-going SO2 monitoring due to the low sulfur content of the fuel.

A405A – Cooling tower requirements – the operational limits (drift rate, TDS, and gpm) in this condition are based upon the parameters used to calculate and set the PM emission limits in this permit. Meeting these requirements demonstrates compliance with limits.

MONITORING SPECIFICATIONS:
[NSR establishes monitoring necessary to ensure compliance with established emission limits and applicable regulations. TV fills out table in accordance with current Monitoring Protocols.

Emission unit Nos.	Parameters To Monitor	To Comply With	Monitoring Required	Monitoring Conditions
N/A, this is not a TV permit				

14.0 <u>For Title V action: Cross Reference Table between NSR Permit 1554 and TV Permit P127R1M1. NSR permit conditions cross referenced to the TV permit are federally enforceable conditions, and therefore brought forward into the TV permit:</u>

NSR Changed by TV*	NSR Condition #	TV Section #
N/A, this is not a TV permit		

15.0 Permit specialist's notes to other NSR or Title V permitting staff concerning changes and updates to permit conditions.

The Environmental Department has determined that there is significant public interest in this permit application, therefore if this permitting action proceeds, a hearing will be held in Spring or Summer 2011.