TECHNICAL SUPPORT DOCUMENT
PROPOSED DRAFT

Permit Number V99-015
November 7, 2006

Table of Contents

1. IDENTIFYING INFORMATION
2. INTRODUCTION
3. PERMITTING HISTORY
4. REVISIONS MADE TO EXISTING PERMIT CONDITIONS
5. SOURCE DESCRIPTION
6. REGULATED ACTIVITIES
7. INSIGNIFICANT ACTIVITIES
8. ALTERNATIVE OPERATING SCENARIOS
9. POTENTIAL EMISSIONS
10. EMISSION LIMITS
11. OPERATIONAL REQUIREMENTS
12. APPLICABLE REQUIREMENTS
13. POTENTIALLY APPLICABLE REQUIREMENTS
14. NONAPPLICABLE REQUIREMENTS
15. STREAMLINING
16. TESTING
17. PERMIT SHIELD
18. COMPLIANCE PLAN
19. HAP IMPACT ANALYSIS
20. AMBIENT AIR QUALITY IMPACT ANALYSIS

Appendix A: Technical Support Document (Ambient Air Quality Impact Report and Engineering Analysis) for Original PSD/Title V Permit

TECHNICAL SUPPORT DOCUMENT

Permit Number V99-015
November 7, 2006

1. IDENTIFYING INFORMATION

Facility Name:	New Harquahala Generating Company, LLC Harquahala Generating Project
Address:	2530 N. 491st Avenue (FedEx/UPS) P.O. Box 727 (U.S. Mail)
City, State, Zip:	Tonopah, AZ 85354
Date Application Received:	The Title V permit renewal application was received from New Harquahala Generating Company, LLC on November 10, 2005 which included a Title V significant permit revision application. This application was superseded by a Title V permit renewal application dated December 16, 2005 and a significant permit revision application dated March 28, 2006. MCAQD is processing the Title V permit renewal and the significant permit revision in parallel.

2. INTRODUCTION

This is a support document intended to provide additional information associated with the issuance of a significant permit revision and a Title V air quality permit renewal to the New Harquahala Generating Company, LLC (NHGC) Harquahala Generating Project (HGP). However, this Technical Support Document (TSD) is not part of the Permit and is not a legally enforceable document.

2.1 Attainment Status of Source Location:

NHGC is located in Tonopah, Arizona, in Maricopa County. Based on the July 1, 2005 version of 40 CFR 81.303, NHGC is located in an area designated as attainment/unclassifiable for all conventional pollutants, i.e., those pollutants for which EPA has established National Ambient Air Quality Standards (NAAQS).

Portions of Maricopa County are designated as nonattainment for PM10 and ozone. However, NHGC is located approximately 18 miles west of the Phoenix PM10 nonattainment area boundary and approximately 28 miles west of the Phoenix-Mesa ozone nonattainment area boundary.

2.1.1 Ozone Attainment Status:

1-Hour Standard - On April 21, 2004, the State submitted the One-Hour Ozone Redesignation Request and Maintenance Plan for the Maricopa County Nonattainment Area (assumed to include the Phoenix metropolitan nonattainment area). On March 21, 2005, EPA proposed to approve Arizona's request to redesignate the Phoenix metropolitan 1-hour ozone nonattainment area from nonattainment to attainment (see 70 FR 13425), and gave final approval of the redesignation on June 14, 2005 with an effective date of June 14, 2005 (see 70 FR 34362).

The 1-hour standard was revoked effective June 15, 2005 for all areas in Arizona (see 40 CFR 81.303 as amended by 70 FR 44470 - 44478) and no longer applies.

8-Hour Standard - On July 18, 1997 (62 FR 38856), EPA revised the ozone NAAQS to establish an 8-hour standard; however, in order to ensure an effective transition to the new 8-hour standard, EPA also retained the 1-hour NAAQS for an area until such time as it determines that the area meets the 1-hour standard. See revised 40 CFR 50.9 at 62 FR 38894 and the above discussion regarding the status of the 1-hour standard for the Phoenix metropolitan 1-hour ozone nonattainment area. As a result of the actions described above, the 8-hour standard has replaced the 1-hour standard for ozone in the Maricopa County nonattainment area.

NHGC is located outside of the area that has been designated as basic nonattainment for the 8-hour standard (see July 1, 2004 version of 40 CFR 81.303). Therefore NHGC is located in an attainment area for the 8-hour ozone standard. Accordingly, ozone and its precursors (NOx and VOC) are regulated under the PSD program.

2.1.2 PM/PM10 Attainment Status:

EPA has deleted Arizona attainment status designations (attainment, unclassifiable and nonattainment) affected by the original national ambient air quality standards (NAAQS) for particulate matter measured as TSP (On June 3, 1993 EPA published a final rulemaking action revising the prevention of significant deterioration particulate matter increments, so that the increments are measured in terms of PM10. Section 107(d)(4)(B) of the Clean Air Act authorizes EPA to eliminate all area TSP designations once the increments for PM_{10} become effective).

No areas in Arizona have been designated as nonattainment for PM2.5. As noted previously, NHGC is located outside of the Maricopa County PM10 nonattainment area. Therefore, PM10 emissions are regulated under the PSD program.

2.2 Major Source Status with Regard to Prevention of Significant Deterioration (PSD)

MCAPCR Rule 240 §210.2 (5/7/03 version) states that "Any stationary source located in an attainment or unclassifiable area that emits, or has the potential to emit, 100 tons per year or more of any conventional air pollutant if the source is classified as a Categorical Source, or 250 tons per year or more of any pollutant subject to regulation under the Act if the source is not classified as a Categorical Source. NHGC is classified as a categorical source and has the potential to emit greater than 100 tons per year of NOx, CO, VOC, and PM10. Thus, the facility is a major stationary source under the PSD regulations.

2.3 Major Source Status with Regard to Hazardous Air Pollutants (HAPs):

Based on the calculations and supporting documentation provided in the NHGC permit application, facility-wide potential HAP emissions do not exceed 10 tons per year of any individual HAP or 25 tons per year of any combination of HAPs. Therefore the facility is not a major source of HAP emissions as defined in 40 CFR 63.2.

3. PERMITTING HISTORY

NHGC began operating under permit V99-015 and is currently authorized to operate under that permit. The following timeline presents a summary of the history on file:

March 17, 2001: Title V/PSD permit was issued to Harquahala Generating Company, LLC.

September 11, 2001: Notification of construction commencement received by the Department from Harquahala

June 18, 2002: The minor modification (1-17-02-01) provided for the following changes to the facility and permit:

- The addition of steam augmentation to boost generating capacity during periods of increased demand.
- Changing the power rating of the emergency back-up diesel generator from 1400 kW to 1500 KW
- Increasing the maximum cooling tower recirculation rate from 103,230 to 135,000 gallons per minute for each of the two cooling towers.
- The installation of ultra-high efficiency drift eliminators to decrease the cooling drift rate from 0.0005% to 0.0003%.
- The change of the cooling tower drift emission factor from 1.093 E-08 (0.0005% drift) to 3.288 E-09 (0.0003%) to reflect the corresponding change in cooling tower drift rate.

October 30, 2002: Most of the changes were made and the permit modification was originally issued in the previous permit revision, however due to an administrative error there were two omissions and a typographical error. These administrative errors were subsequently corrected on October 30, 2002, and the corrected version of the modified permit was re-issued to the applicant.

The following administrative corrections were performed:

- Footnote j of condition 18.A.2 - an emission factor for the calculation of PM_{10} emissions was corrected from 1.093-E-08 to 3.288E-09. A 0.0005% drift rate was also changed to 0.0003%.
- Condition 19.C - 0.0005 was corrected to 0.0003
- The word towers" was changed to "towers' ".

January 30, 2003 Initial Start up of Combustion Turbine Unit 1 (CTG1)

March 26, 2003: Accelerated Minor Modification.

- Changed the term “Combustion Turbine” to “Combined Cycle Unit” in permit condition 18.A.2 and throughout the permit.
- In Table 1, the allowable PM_{10} emissions were decreased to 3.1 tpy from 4.12 tpy.
- In Table 3, the allowable hourly emissions for each combined of CO during SU/SD were increased to 2,300 pounds from 2,000 pounds during a cold start
- Permit condition 18.A.2)c), the definition of startup was changed from 75% of nameplate capacity to 75% of rated capacity.

- o Modified permit condition 18.A.2.g to reflect the requirements of 40 CFR 60 subpart GG.
- o Footnote j of condition 18.A.2 – the assumption of 50% of particulate being PM_{10} was changed to 31.5 %. This was the reason the emission factor for PM_{10} was also decreased from 3.288E-09 to 2.071 E-09.
- o The cooling tower TSD limit was increased from 7,300 to 11,000 ppm
- o The ammonia injection rate that triggers additional source testing was removed and replaced with more frequent testing (every 12 months following 3-year period after initial startup or catalyst replacement).

May 29, 2003: Initial Start up of Combustion Turbine Unit 2 (CTG2)

July 30, 2003: Initial Start up of Combustion Turbine Unit 3 (CTG3)

November 9, 2005: Title V Permit Renewal with Significant Revision Application submitted

December 15, 2005: Title V Permit Renewal (without Significant Revision) Application submitted

February 7, 2006: Order of Abatement by Consent (OAC) V-0007-06-GLB signed resolving Notice of Violation AU-01-26-06-01for failure to file a timely application for Air Quality Operating Permit renewal. Order terminates on the date MCAQD issues a renewed Air Quality Operating Permit to NHGC or one (1) year from the effective date of the Order, whichever occurs sooner.

March 28, 2006: Updated Title V Permit Renewal with Significant Revision Application submitted

4. REVISIONS MADE TO EXISTING PERMIT CONDITIONS

In their significant revision permit application, NHGC requested various changes to existing permit conditions. The subsections below document the Applicant-requested permit changes and corresponding MCAQD technical/regulatory analyses and conclusions.

4.1 Name and Address Update

<u>Requested Change:</u>

NHGC requested that the Permittee Name and Facility Address fields on the permit cover/signature page be updated to reflect the permit transfer effective June 30, 2003. The updated information is as follows:

New Harquahala Generating Company, LLC
HARQUAHALA GENERATING PROJECT
2530 North 491st Avenue
Tonopah, Arizona 85354

<u>Conclusion:</u>

The Permittee name and address changes were made as requested.

4.2 Permit Expiration Date

Requested Change:
NHGC requested that the permit cover/signature page explicitly state the permit issuance and expiration date, rather than reference the permit cover letter.

Conclusion:
MCAQD will scan the permit signature page including the issuance and expiration dates and attach this with the electronic permit file.

4.3 Harmonizing CEMS QA/QC procedures – 40 CFR Part 60 and 40 CFR Part 75

Requested Change:
Section 19.G.1 of the Title V air permit requires that the Continuous Emissions Monitoring Systems (CEMS) meet or exceed all applicable design, installation, operations, quality assurance, and all other applicable requirements of 40 CFR Parts 60 and 75. The facility must comply with both the New Source Performance Standards (NSPS, 40 CFR 60) and Acid Rain Monitoring (40 CFR 75) continuous emissions monitoring standards, including Quality Assurance and Quality Control (QA/QC) procedures.

NHGC requested that Condition 19.G.1 be revised to allow the use of Part 75 QA/QC procedures the combined cycle unit NOx CEMS as follows:

G. Operational Requirements for the Continuous Emissions Monitoring Systems
The CEMS shall meet or exceed all applicable design, installation, operational, quality assurance, and all other applicable requirements of 40 CFR Parts 60 and 75. <u>The procedures under 40 CFR 60.13 and 75.12 shall be followed for the installation, evaluation, and operation of these CEM systems. Compliance with the quality assurance and quality control requirements in 40 CFR 75, Appendix B, for the NO_x monitoring system shall be allowed in lieu of the quality assurance and quality control procedures in 40 CFR 60, Appendix F</u>.

Analysis
Revisions to NSPS subpart GG were promulgated on July 8, 2004. Among other things, EPA harmonized CEMS requirements by allowing the use of Part 75 certification and QA/QC procedures for the purpose of the NSPS. The following citations from the July 8, 2004 preamble and revised rule document the changes:

"…many of the units affected by subpart GG are already required to install and certify CEMS for NOx under other requirements, such as the acid rain monitoring regulation in 40 CFR part 75, or through conditions in various permit requirements. To reduce the burden on these units, we are allowing the use of CEMS units that are certified according to the requirements of 40 CFR part 75. The 40 CFR part 75 testing procedures to certify the CEMS are nearly identical to those in 40 CFR part 60, and 40 CFR part 75 has rigorous quality assurance and quality control standards. Therefore, it is appropriate to allow the use of 40 CFR part 75 CEMS data for subpart GG compliance demonstration."[1]

"If the owner or operator has installed a NOx CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the

[1] See FR 69 41348, July 8, 2004.

CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).”[2]

Conclusion:

The language of NSPS subpart GG, as revised on July 8, 2004, allows the requested flexibility with regard to NOx CEMS procedures. However, EPA Region 9 has taken the position that Part 75 QA/QC provisions as applicable to low-span CEMS and low emission rate units are insufficient for the purpose of BACT. Where reduced stringency QA/QC is provided under Part 75, the source must meet the corresponding requirements of 40 CFR 60 Appendix F. Specifically:

(1) Calibration Error: Monitors with span values less than or equal to 50 ppm utilizing the alternative 5 ppm performance specification in 40 CFR Part 75 shall meet the Calibration Drift performance specification and QA/QC requirements of 40 CFR 60 Appendix B: Performance Specification 2 (PS-2) and Appendix F.

(2) Linearity: Monitors with a span values less than or equal to 30 ppm exempted from linearity check requirements under 40 CFR Part 75 and monitors utilizing the alternative 5 ppm difference performance specification in 40 CFR Part 75 shall meet the Relative Accuracy performance specifications and Cylinder Gas Audit (CGA) or Relative Accuracy Audit (RAA) requirements of 40 CFR 60 Appendix F.

(3) Relative Accuracy Test Audit (RATA): Monitors utilizing the alternative 0.020 lb/MMBtu RATA performance specification in 40 CFR Part 75 shall meet the Relative Accuracy performance specifications and RATA requirements of 40 CFR 60 Appendix F.

As documented in Section 4.9 of this TSD, MCAQD reorganized the permit, moving the CEMS requirements from Section 19 – Operational Requirements to Section 20 – Monitoring and Recordkeeping. NOx CEMS requirements referencing the applicable provisions of 40 CFR Part 75 and Part 60 are contained in Section 20.A.3 of the revised permit.

4.4 Periodic Tuning of DLN Combustors and SCR Systems

Requested Change:

NHGC requested that the permit be revised to allow periodic tuning of dry low NOx (DLN) combustors and SCR systems without creating noncompliance with the applicable NOx BACT limits. According to NHGC, tuning of the DLN and SCR systems will result in improved pollution control efficiency, better control of the ammonia use, and combustion optimization. However, tuning activities may result in brief excursions above the applicable 2.5 ppmv NOx BACT emission limit. This is due to the need to operate the combined cycle unit(s) at low load or other non-ideal combustion conditions to achieve tuning objectives.

The expected duration of tuning activities is two 10-hour days for each semi-annual activity, as well as 10 hours for major maintenance activities associated with the combustion section of the

[2] 40 CFR 60.334(b)(3)(iii).

turbines (per unit). NHGC requested that the permit be revised to incorporate 50 hours per year per combined cycle unit of allowed operation in tuning mode, and that the warm/hot start/shutdown emission limits for NOx, CO, and VOC would apply during tuning events.

Analysis

DLN combustors are an integral part of the combustion process, utilizing pre-mixed air/fuel technology and staged combustion to minimize flame temperatures and thereby reducing thermal NOx formation. DLN combustors generate NOx emissions in the range <=35 ppmvd at 15% O_2, versus approximately 165 ppmvd at 15% O_2 for conventional combustor technology.

The NHGC combined cycle units utilize selective catalytic reduction (SCR) for post-combustion NOx control to achieve compliance with the 2.5 ppmvd NOx limit (at 15% O_2). SCR is a process that involves removal of NOx from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion turbine exhaust gas reacts with nitrogen oxides and oxygen to form molecular nitrogen and water vapor. The SCR reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NOx decomposition reaction. Technical factors related to this technology include the catalyst reactor design, maintaining the optimum operating temperature, sulfur content of the fuel, and design and proper operation of the NH_3 injection system.

The requested permit revision will allow tuning to be completed on the NHGC combustion turbines and associated SCR systems. Tuning activities would be conducted a minimum of twice per year, on each unit, typically planned for spring and fall. This timing allows for optimal settings as they relate to ambient conditions. Tuning may also be required following maintenance work on the combustion systems or SCR components.

Optimal performance of the DLN combustors and SCR system requires periodic tuning to adjust the combustion dynamics and ammonia injection system in order to achieve optimum NOx control efficiency. All tuning operations will be performed in accordance with the turbine manufacturer's procedures using qualified personnel. During DLN tuning, the procedure requires that the SCR continue to operate to minimize NOx emissions. The CEMS data acquisition system will also be programmed to receive a command initiating "tuning in progress" and will employ the "alternate" emissions limits for display and reporting purposes.

All emissions during tuning are recorded by the CEM systems, and are counted towards the annual emissions limitations, which remain unchanged. NHGC demonstrated in their permit application that given the same number of operating hours; tuning of the DLN combustors and SCR systems results in an overall decrease in annual NOx emissions. The example below (from the permit application) illustrates the benefits of DLN and SCR tuning for 6,000 operating hours in a typical year. The example utilizes 50 hours of tuning per year and results in a nominal 8% reduction in NOx emissions from periodic tuning, equating to a reduction of more than two tons per year for a single CT/HRSG.

WITHOUT DLN/SCR TUNING

Hours per year per CT/HRSG	Ambient Temperature (deg F)	Load Condition (% CT Load)	GT Heat Input (million Btu/hr, HHV)	Stack NOx (lb/hr)	NOx (TPY)
4000	36	BASE	2530.8	24.2	48.47
500	36	90%	2286.7	21.9	5.47
500	36	80%	2094.4	20.1	5.01
500	36	70%	1884.1	18.0	4.50
500	36	60%	1681.6	16.0	4.01
0	36	Tuning	2530.8	151.0	0.00
6000			**Tons per year of NOx without tuning**		**67.48**

WITH TUNING (Nominal 8 % reduction in NOx emissions)

Hours per year per CT/HRSG	Ambient Temperature (deg F)	Load Condition (% CT Load)	GT Heat Input (million Btu/hr, HHV)	Stack NOx (lb/hr)	NOx (TPY)
3990	36	BASE	2530.8	22.3	44.48
490	36	90%	2286.7	20.1	4.94
490	36	80%	2094.4	18.5	4.52
490	36	70%	1884.1	16.6	4.06
490	36	60%	1681.6	14.8	3.62
50	36	Tuning	2530.8	151.0	3.78
6000					**65.39**

Improvement due to tuning is 2.09 tons per year per CT/HRSG

Conclusion:

Tuning events are conducted on an infrequent basis and are required to maintain efficient operation of the combined cycle units and associated SCR control systems. The existing permit does not provide any allowance for tuning, therefore potentially creating a disincentive. Tuning is expected to reduce actual annual emissions, and there will be no increase in allowable annual emissions of NOx, CO, and VOC. The short-term (lb/hr) emission limits applicable to tuning/testing mode operation are consistent with those established for warm/hot start/shutdown. NHGC is required to monitor NOx and CO emissions using CEMS to demonstrate compliance with short-term and annual emissions limitations, which remain unchanged.

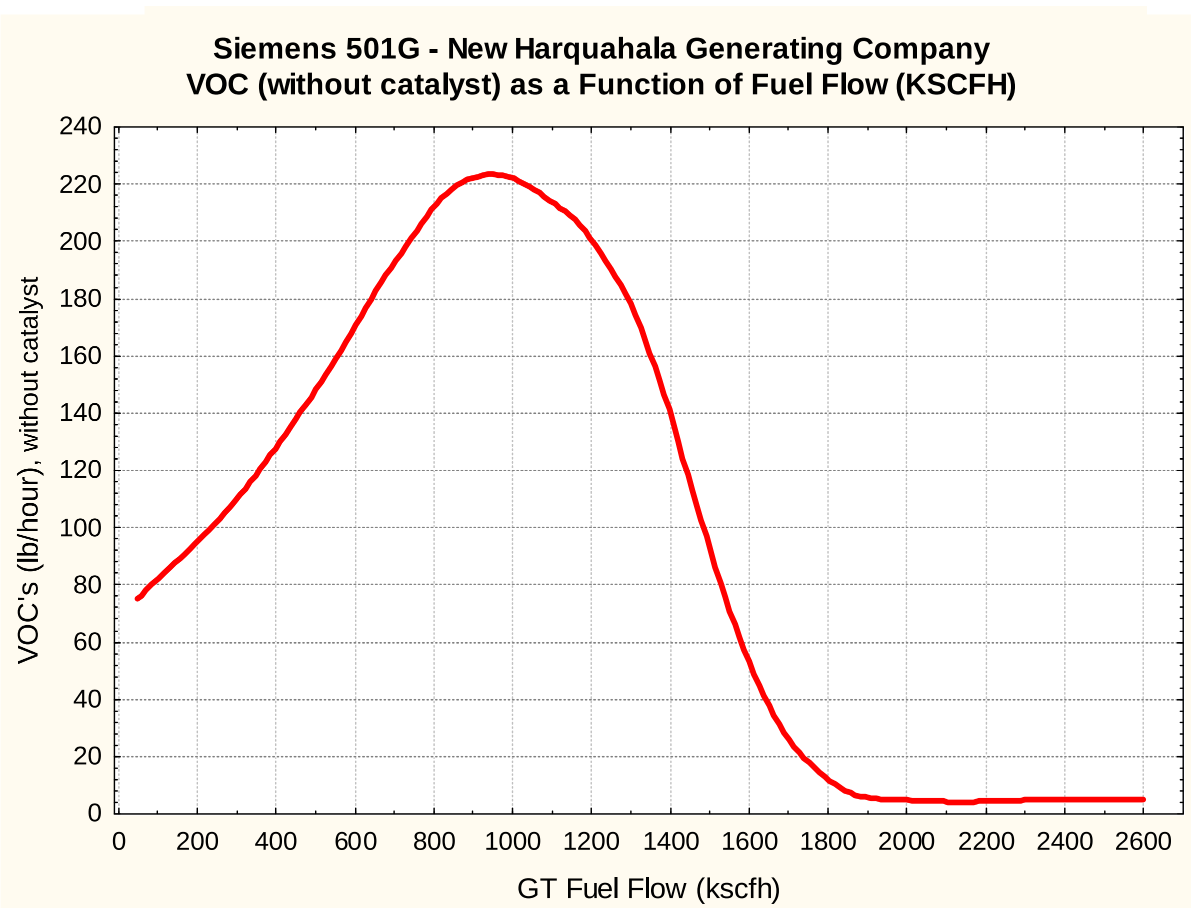
The permit was revised to incorporate tuning/testing operation emission limits, monitoring and recordkeeping, and reporting provisions. Although NHGC did not specifically address testing in its request, information from other combined cycle power plants in the County indicates the potential need to conduct periodic generator certification testing. To address this, the revised permit language was structured generally to include tuning and testing activities not limited to the specific categories identified in the permit application. 24-hour advanced notification is required prior to conducting any tuning/testing activity, and total annual operation in tuning/testing mode (excluding periods of tuning/testing during which normal operating limits are complied with) is limited to 50 hours per calendar year per combined cycle unit. Additionally, the revised permit specifies that no more than one combined cycle unit shall be in tuning/testing mode at any time.

4.5 VOC Emissions Calculation Methodology

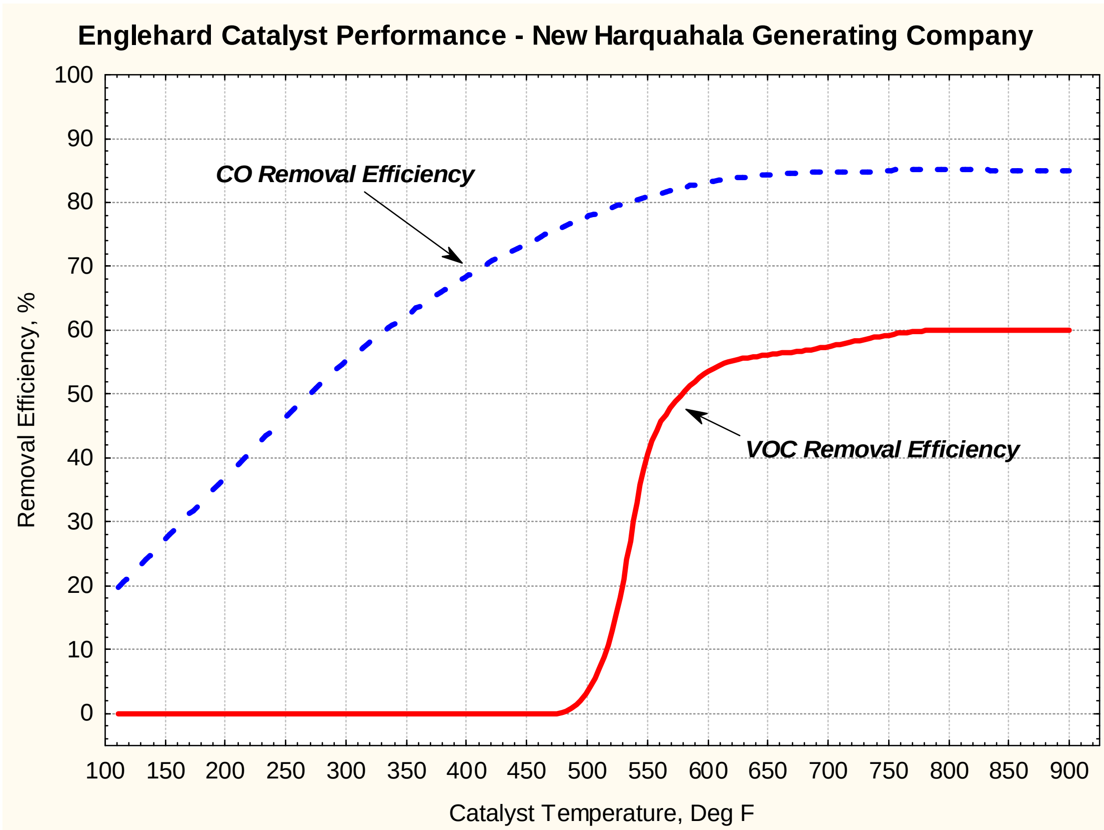
Requested Change:
NHGC requested the incorporation of a new VOC emissions calculation methodology into the permit. The new methodology is based on updated information from the combustion turbine vendor (Siemens) and oxidation catalyst vendor (Engelhard). A mathematical model was developed based on updated vendor information and the variables fuel flow and catalyst temperature. VOC emissions during startup, shutdown, and tuning/testing operating scenarios can be estimated more accurately using the model. VOC emissions during normal operation would be estimated using a conservative test data-derived emission factor.

Analysis
The original NHGC permit application was based on very preliminary emissions estimates from Siemens-Westinghouse Power Generation for their new 501G combustion turbines. The emissions values, especially for CO and VOC emissions, were very conservative due to the fact that these units had not been operated for sustained periods at other sites prior to the time the NHGC permit application was being developed.

501G/HRSG VOC emissions are a function of fuel flow as shown in the figure below, representing uncontrolled VOC emissions from startup to full load operation.



The NHGC combustion turbines/HRSGs are equipped with oxidation catalysts that reduce the amount of CO and VOC emissions. Engelhard, Inc supplies the catalyst. The removal efficiency of the catalyst as a function of catalyst temperature is illustrated in the figure below. Below 500° F, the removal efficiency for VOC is virtually zero, with a maximum removal efficiency of a nominal 60% for VOC.



Two (2) mathematical models were developed: (A) a model to compute the uncontrolled VOC emissions as a function of fuel flow, and (B) a model to compute the oxidation catalyst VOC removal efficiency as a function of catalyst temperature. Using both models, the "controlled" VOC emissions are computed as follows:

$$\text{VOC controlled} = \text{VOC (uncontrolled, A)} * \left(1 - \frac{B}{100}\right)$$

The calculation for VOC (uncontrolled) as a function of fuel flow, created using non-linear multiple regression, is shown in the table below.

A0	3094.926	B0	-35.6432	C0	89.13482
A1	-3.84947	B1	0.301360	NG	= Natural Gas Flow, KSCFH
A2	0.167581	B2	0.012542	NG2	= (NG/10)^2
A3	-0.245080	B3	-0.182930	NG3	= (NG/100)^3
A4	-272.680	B4	13.61226	INVNG	= (1000/NG)

VOC1 = A0 + A1*NG + A2*NG2 + A3*NG3 + A4*INVNG
VOC2 = B0 + B1*NG + B2*NG2 + B3*NG3 + B4*INVNG

If VOC1 < C0, then VOC (uncontrolled) = VOC1
If VOC1 >= C0, then VOC (uncontrolled) = VOC2

The calculation of VOC (uncontrolled) is in the units of lb/hr.

The calculation for the oxidation catalyst VOC removal efficiency (%) as a function of catalyst temperature (deg F), created using non-linear multiple regression, is shown in the table below

C0	-13222.42	D0	31680.84	E0	28.1667
C1	51.77139	D1	-68.84173	CTEMP	= Catalyst Temp, deg F
C2	-8.91299	D2	6.64747	CTEMP2	= (CTEMP/10)^2
C3	56.93445	D3	-24.00794	CTEMP3	= (CTEMP/100)^3
C4	12528.57613	D4	-54404.5396	INVCTEMP	= (100/CTEMP)

CTL1 = C0 + C1*CTEMP + C2*CTEMP2 + C3*CTEMP3 + C4*INVCTEMP
CTL2 = D0 + D1*CTEMP + D2*CTEMP2 + D3*CTEMP3 + D4*INVCTEMP

If CTL1 < E0, then CTLEFF = CTL1
If CTL1 >= E0, then CTLEFF = CTL2

The calculation of control efficiency (CTLEFF) is in the units of percent (%).

Therefore, the calculation of controlled VOC emissions, as a function of fuel flow and catalyst temperature, becomes:

VOC (controlled, lb/hr) = VOC (uncontrolled, lb/hr) * (1- (CTLEFF/100))

The use of these catalyst efficiency and VOC mass emission calculations can be used to more accurately estimate VOC emissions during startup and shutdown events. VOC emissions during startup and shutdown will be calculated in accordance with the above formulas. Once the combustion turbine/HRSG is in normal operation, the mass emission rate calculation will default to the emission factor approach currently employed. Based on stack test results and Vendor supplied emissions data, the recommended emission factor is 0.0012 lb VOC per million Btu (HHV basis). This factor represents the maximum emission rate value for all loads of 60% or greater. The normal operation VOC mass emission rate calculation is as follows:

VOC (controlled, lb/hr) = 0.0012 lb/million Btu * Heat input (million Btu/hr)

Conclusion

The proposed revision incorporates a more robust and accurate VOC estimation procedure based on current vendor information and operating experience with the Siemens-Westinghouse 501G combustion turbines. Permit conditions incorporating revised VOC emission calculation procedures are shown below.

MONITORING AND RECORDKEEPING REQUIREMENTS:

A. Monitoring and Recordkeeping Requirements for the Combined Cycle Units:

9) VOC emissions from the Combined Cycle Units during normal operating conditions shall be calculated using the emission factors contained in the Permit Application amended on March 28, 2006 and unit-specific fuel usage data, unless an alternative emission rate can be demonstrated to the satisfaction of the Control Officer and the Administrator to be more representative of emissions.

10) VOC emissions from the Combined Cycle Units during startup, shutdown, and testing/tuning operating conditions shall be calculated based on fuel flow and oxidation catalyst temperature in accordance with the mathematical model contained in the Permit Application amended on March 28, 2006, unless an alternative emission rate can be demonstrated to the satisfaction of the Control Officer and the Administrator to be more representative of emissions.

4.6 Startup/Shutdown (SU/SD) Definitions

Requested Change:

NHGC requested that the definitions of SU/SD operation (including cold and hot/warm SU/SD be revised to better comport with the operational capabilities of the NHGC combined cycle units. The current SU/SD definitions contain two criteria that unnecessarily prolong startups and restrict operation at lower load levels (i.e., 50% – 75% load).

Under the current permit, startup is not terminated until the exhaust gas temperature at the inlet to the oxidation catalyst system reaches 600º F, and both the startup and shutdown definitions contain a 75% electrical load criterion (i.e., startup does not end until the Unit reaches 75% of rated capacity and shutdown is initiated when the Unit falls below 75% of rated capacity. NHGC requested that the startup definition be revised to lower the load threshold to 50% and incorporate the Combined Cycle Unit control system digital signal “Final Mode” in place of oxidation catalyst inlet gas temperature. NHGC requested that the definition of shutdown be revised to also incorporate the control system digital signal “Final Mode,” remove the 75% load criterion, and clarify qualification of unit ‘trips’ and aborted startups.

Analysis:

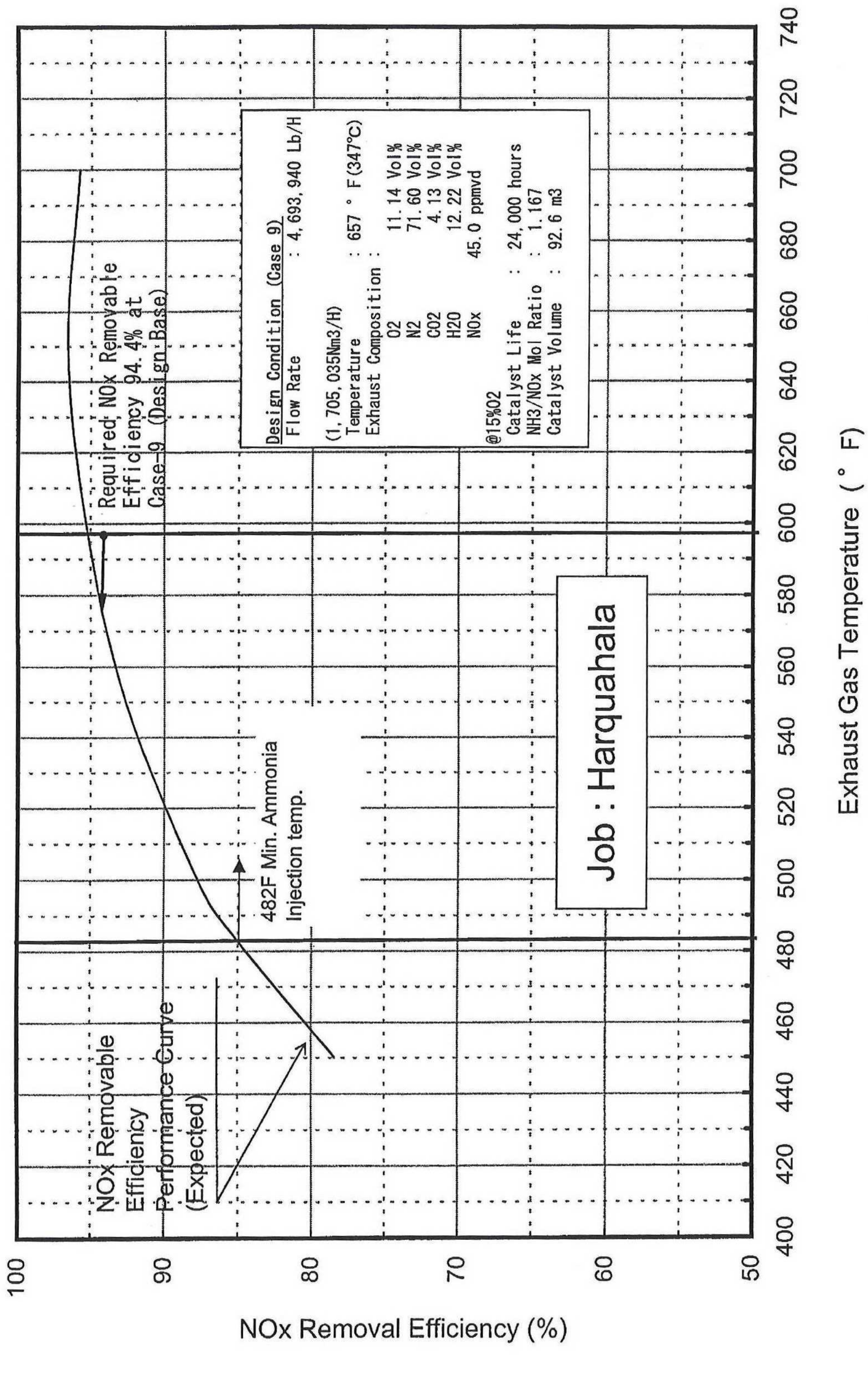
The current Title V permit startup and shutdown definitions (Conditions 18.c and 18.d) read as follows:

“Startup is defined as the period between when a Combined Cycle Unit is initially started until the temperature of the Combustion Turbine’s exhaust prior to entering the Selective Catalytic Reduction system and prior to entering the Oxidation Catalyst system reaches 600 degrees Fahrenheit (316 degrees Centigrade) and the electrical load of the Combustion Turbine increases to 75% of rated capacity. Rated capacity means the combustion gas turbine’s

nameplate capacity adjusted to current inlet conditions. Cold startup is defined when a startup occurs when the steam turbine rotor temperature is less than 302 degrees Fahrenheit (150 degrees Centigrade). Hot startup or warm startup is defined when a startup occurs when the steam turbine rotor temperature is 302 degrees Fahrenheit (150 degrees Centigrade) or greater."

"Shutdown is defined as the period during a shutdown sequence beginning when the electrical load of a Combustion Turbine drops below 75% of rated capacity and ending when combustion has ceased."

According to NHGC, these definitions were based on the conservative assumptions that (1) the units could not operate below 75% of rated capacity and still meet applicable 'normal operation' emission limits and (2) ammonia injection to the SCR could not begin until the catalyst temperature was at or above 600° F. While the rotor temperature definitions for cold and hot/warm startups remain valid, NHGC has the ability to initiate or maintain SCR operation at a lower load (i.e., less than 75%). The figure below illustrates the vendor SCR performance curve setting 482 °F as the minimum catalyst temperature for ammonia injection.



Design Condition (Case 9)
Flow Rate : 4,693,940 Lb/H
(1,705,035Nm3/H)
Temperature : 657 ° F(347°C)
Exhaust Composition :
O2 11.14 Vol%
N2 71.60 Vol%
CO2 4.13 Vol%
H2O 12.22 Vol%
NOx 45.0 ppmvd
@15%O2
Catalyst Life : 24,000 hours
NH3/NOx Mol Ratio : 1.167
Catalyst Volume : 92.6 m3
Required NOx Removable Efficiency 94.4% at Case-9 (Design Base)
NOx Removable Efficiency Performance Curve (Expected)
482F Min. Ammonia Injection temp.
Job : Harquahala
Exhaust Gas Temperature (° F)
NOx Removal Efficiency (%)
400
420
440
460
480
500
520
540
560
580
600
620
640
660
680
700
720
740
50
60
70
80
90
100

The use of the "Final Mode" operating signal to signify the end of startup and beginning of shutdown represents a more appropriate operating mode metric. According to Siemens emissions test data for the 501G Combustion Turbines, NHGC has the ability to operate in Final Mode between 50 and 75% of base load while meeting all permitted emissions limits. NHGC combined cycle Unit NOx and CO emissions are continuously monitored by CEMS, and historical operating data demonstrate that the units can operate between 50 and 75% load and still meet the applicable 'normal operation' concentration (ppmvd at 15% O_2), emission rate (lb/million Btu), and mass emission (lb/hr) limits. Based on vendor supplied data, VOC emissions are also expected to remain well within permitted emission limits at 50% - 75% load operation.

As shown in the table below, operation at lower minimum load will result in lower emissions. Therefore, allowing the combined cycle units to operate between 50% and 75% load to satisfy dispatch will result in lower mass emissions than requiring operation only at 75% load and higher.

OPERATION AT 75% LOAD OR GREATER

Hours per year per CT/HRSG	Ambient Temperature (deg F)	Load Condition (% CT Load)	Stack NOx (lb/hr)	NOx (TPY)
1500	36	BASE	24.2	18.18
500	36	90%	21.9	5.47
500	36	80%	20.1	5.01
0	36	70%	18.0	0.00
0	36	60%	16.0	0.00
0	36	50%	14.0	0.00
0.00	36	30%	209.2	0.00
0.00	36	20%	159.2	0.00
0.00	36	10%	134.6	0.00
0.00	36	FSNL	111.5	0.00
3500	59	BASE	22.7	39.69
1500	59	90%	20.4	15.34
1260	59	80%	18.8	11.86
0	59	70%	17.1	0.00
0	59	60%	15.3	0.00
0	59	50%	13.5	0.00
8760				**95.55**

OPERATION AT 50% LOAD OR GREATER

Hours per year per CT/HRSG	Ambient Temperature (deg F)	Load Condition (% CT Load)	Stack NOx (lb/hr)	NOx (TPY)
1500	36	BASE	24.2	18.18
500	36	90%	21.9	5.47
200	36	80%	20.1	2.01
200	36	70%	18.0	1.80
200	36	60%	16.0	1.60
100	36	50%	14.0	0.70
3500	59	BASE	22.7	39.69
1500	59	90%	20.4	15.34
560	59	80%	18.8	5.27
200	59	70%	17.1	1.71
200	59	60%	15.3	1.53
100	59	50%	13.5	0.68
8760				**93.98**

Conclusion:
NHGC provided sufficient supporting basis for revising the startup and shutdown operating condition definitions as requested. The definitions were revised substantially as requested, but with the addition of a maximum startup event duration limitation. The basis for this additional requirement is discussed in Section 4.7. The revised SU/SD definitions are as follows:

OPERATIONAL REQUIREMENTS:

B. Operational Requirements for Combined Cycle Units:

2) Startup, Shutdown, Testing and Tuning Operating Conditions

a) Startup is defined as the period between when a Combined Cycle Unit is initially started and fuel flow is indicated until Combustion Turbine generation increases above 50% of rated capacity and the fuel system confirms, via digital signal, "Final Mode" of operations has been established. Rated capacity means the combustion gas turbine's nameplate electrical power output capacity in megawatts (MW) adjusted to current inlet conditions. Cold startup is defined as a startup that occurs when the steam turbine rotor temperature is less than 302 degrees Fahrenheit (150 degrees Centigrade). Hot startup or warm startup is defined as a startup that occurs when the steam turbine rotor temperature is 302 degrees Fahrenheit (150 degrees Centigrade) or greater. For the purpose of emission limit applicability, the total duration of any Combined Cycle Unit startup event (cold, hot or warm startup) shall not exceed 5 hours, except that the Permittee is allowed up to 3 startup events per calendar year lasting longer than 5 hours but not to exceed 8 hours. Restart of a Combined Cycle Unit following a unit trip or aborted startup constitutes a new startup period.

b) Shutdown is defined as the period during a Combined Cycle Unit shutdown sequence beginning when the operator initiates the shutdown of the unit and the fuel system confirms, via digital signal, that the units is no longer operating in Final Mode operations and ending when all combustion has ceased. In the event of a unit trip or aborted startup, shutdown begins when the combustion turbine drops off Final Mode operations and ends when all combustion has ceased. Restart of a Combined Cycle Unit following a unit trip or aborted startup constitutes a new startup period.

4.7 Removal of Startup Event Limits and Annual SU/SD Hours Limitations

Requested Change:
NHGC requested removal of the pound/event startup limitations and limitations on hours of operation in SU/SD mode (10 hours per calendar day and 700 hours per year per combined cycle unit) contained in the current permit. In summary, the bases and justification for this request were as follows:

- Removal of lb/event SU/SD emissions limitations in favor of lb/hour and ton/yr limits only was requested to reduce monitoring/recordkeeping burden and meet MCAQD objectives for enhanced enforceability and consistency among combined cycle plant permits within the County.
- Electrical market projections relied upon in developing the initial NHGC permit application and estimated total SU/SD events per year are inconsistent with the current

demand. The annual limit on hours of operation in startup/shutdown mode constrains NHGC's ability to operate as necessary to meet market demand.

- Current pound-per-hour and ton-per-year BACT limitations will remain unchanged and are not jeopardized by removal of the SU/SD hours limitations. Compliance with these limitations is demonstrated by CEMS (NOx and CO) or emissions model calculations (VOC) on an hourly and 365-day rolling total (NOx and CO) or 12-month rolling total (VOC) basis.
- The technology and work practices used on the NHGC combined cycle units – SCR and oxidation catalyst control systems and good engineering practices, constitute BACT for SU/SD operations.

Analysis:

Lb/event SU/SD limits **-** Table 4 of the current Title V permit contains NOx, CO, and VOC emissions limitations in units of pounds per SU/SD event. These limitations are in addition lb/hr limitations for specific SU/SD scenarios and ton/year limitations applicable to all operating scenarios. A review of County combined cycle plant Title V permits revealed inconsistency in the expression of SU/SD limitations. MCAQD objectives are to harmonize all combined cycle plant permit SU/SD limitations to a lb/hr basis and remove lb/event limitations where currently imposed, unless otherwise required to meet regulatory requirements and/or support air quality impact demonstrations. In the case of NHGC, only the CO lb/event limit is integral to the ambient air quality impact demonstration. MCAQD determined that the 3,000 lb CO/event limitation was necessary to support the CO NAAQS demonstration for the 8-hour averaging period. As discussed in further detail in Section 20 of this TSD, maximum 8-hour average CO emissions used in the most recent SU/SD scenario NAAQS modeling demonstration relied upon the 3,000 lb CO/event limit. Removal of this requirement would result in an increase in theoretical (allowable) emissions over an 8-hour period, potentially invalidating the prior modeling demonstration. Therefore, the CO lb/event limitation was maintained in Section 18.A, Table 3 of the revised draft permit.

The revised permit incorporates a new SU event duration limit consistent with good engineering practices (GEP) and demonstrated NHGC combined cycle unit performance. The following language was added to Condition 19.B(2)(a): "*For the purpose of emission limit applicability, the total duration of any Combined Cycle Unit startup event (cold, hot or warm startup) shall not exceed 5 hours, except that the Permittee is allowed up to 3 startup events per calendar year lasting longer than 5 hours but not to exceed 8 hours.*" NHGC provided actual operating data for cold and hot/warm SU events supporting these startup duration limits as representative of GEP and demonstrated capability. It should be noted that actual startup durations are less than the allowed 5 hours; however, in accordance with MCAQD policy, operating mode and associated compliance monitoring is performed on a clock hour basis (i.e., each clock hour is designated in one operating mode). The 5-hour SU event duration is necessary to accommodate normal GEP startups based on NHGC combined cycle unit operating history and the clock hour monitoring approach used.

No changes to the lb/hr SU/SD emission limits or ton/yr emission limits applicable to all operating scenarios were made. However, for improved compliance assurance and enforceability, the ton/yr limits for NOx and CO were revised from a 12-month rolling total basis to a 365-day rolling total basis.

SU/SD hours limitations **-** Condition 19.B of the current Title V permit contains the following SU/SD operational requirements:

B. Operational Requirements for the Combined Cycle Units:

"Each Combined Cycle Unit shall operate such that the total combined hours in both the startup and shutdown modes for each unit does not exceed 700 hours per year, calculated on a rolling 12 calendar month basis, and 10 hours per calendar day. For purposes of this Permit Condition, startup and shutdown are as defined in Notes (c) and (d) after Table 5 in Permit Condition 18.A.2."

MCAQD was unable to identify the regulatory basis for the current 10-hour per calendar day SU/SD limitation for each combined cycle unit. Applicable averaging times for the National Ambient Air Quality Standards (NAAQS) for pollutants affected by SU/SD operations (i.e., NOx and CO) are 1-hour and 8-hour (CO) and annual (NOx). Therefore, the 10-hour/day SU/SD limitation serves no purpose with respect to protection of the NAAQS. Significant operational and economic incentives already exist to limit startup frequency and duration to the greatest extent possible while still meeting electrical demand and maintaining safe/reliable operation of the combined cycle units. Robust monitoring systems are in place to ensure compliance with BACT limitations, including ton/yr limitations which apply to all operating conditions including SU/SD. Therefore, the 10-hour/day SU/SD limitation per combined cycle unit is unnecessary.

Annual SU/SD hours limitations contained in the current permit (700 hours/yr/combined cycle unit) are based on Company representations made by during original permitting of NHGC in 2000. Anticipated maximum annual hours of SU/SD reflected forecasted electrical market conditions at that time. The current electrical market requires more frequent startups and shutdowns then originally anticipated. The hour/yr SU/SD limitations now potentially constrain NHGC's ability to operate the combined cycle units as necessary to meet market demand. Rather than raise or reapportion the annual SU/SD hours allowance as initially requested by NHGC, MCAQD determined such limitations were unnecessary and could be removed from the permit without jeopardizing BACT compliance. This conclusion was based on the following factors:

1. Annual SU/SD duration limitations are not necessary to ensure and demonstrate compliance with the applicable ton/yr BACT limitations for NOx, CO, and VOC, which will remain unchanged. These annual emission limitations apply regardless of operating mode or total duration of startups and shutdowns. Compliance with ton/yr BACT limitations is determined using CEMS for NOx and CO (365-day rolling total) and test data-derived emission factor/model for VOC (12-month rolling total). Missing data procedures are specified to ensure complete accounting of emissions even during periods of monitor downtime.
2. The total duration of SU/SD operation per year is a factor of electrical market demand over which NHGC does not have direct control. The County determined that it was not appropriate to limit the total number or duration of SU/SD events per year as a component of BACT. Rather, a limit on the maximum duration of any SU/SD event was applied as an operational work practice under BACT. This approach is supported by a recent EPA permitting action for a combined cycle power plant in Washington.[3]
3. As documented below, the annual SU/SD duration limitations do not limit annual emissions below allowable annual ton/yr rates. The ton/yr BACT emission limits are more restrictive; therefore, the permit action does not constitute a 'change in the method of

[3] See Preliminary Technical Support Document for Diamond Wanapa I, L.P. Wanapa Energy Center; prepared by USEPA Region 10, Seattle, WA; 11/17/2004.

operation' that will 'result in' an increase in emissions (i.e., a modification in the context of NSR/PSD).

4. MCAQD required NHGC to prepare an updated BACT analysis for SU/SD operation of the combined cycle units to support the proposed permit revision. The results if that analysis, documented below, indicate that the emission limits and work practice standards contained in the revised permit constitute BACT for SU/SD operation.

Demonstration of no increase in emissions – Actual emissions under various operating modes, including cold, hot/warm SU and normal operation at full load, were evaluated based on conceptual annual operating scenarios to ensure that the removal of the annual hours of SU/SD limitations would not result in an increase in emissions. The table below summarizes annual emissions for various startup scenarios in comparison to the annual emission limits per unit. The NHGC annual emissions totals found in the original permitting for the facility were based on emissions scenarios using 10 cold startups, and 30 hot/warm startups. The resulting annual emissions were considered BACT for the Siemens 501G combustion turbines equipped with SCR and oxidation catalysts. Assuming 700 startup hours per unit as allowed by the current Title V permit and base-load operation for the remainder of the year, emissions would exceed the allowable annual NOx, CO, and VOC limits contained in the permit. Therefore, it was concluded that the annual SU/SD duration limits do not constrain or otherwise 'bottleneck' annual emissions to some level below allowable ton/yr rates.

# Cold Startups per Year	**# Hot/Warm Startups per Year**	**Operating Hours at 100% Load, 59 deg F**	**NO_x (tpy)**	**CO (tpy)**	**VOC (tpy)**
Current Annual Limits per Unit			***108***	***192***	***34***
0	0	8760	99.3	39.7	6.3
10	30	8600	107.8	86.2	21.7
30	100	8240	**126.7**	191.0	**56.1**
100	100	7960	**141.5**	**272.4**	**82.9**
100	200	7560	**162.5**	**388.8**	**121.3**

BACT Analysis - To support the proposed changes to SU/SD related permit conditions, MCAQD required that NHGC prepare an updated BACT analysis for the combined cycle units. Per agreement with USEPA Region 9, the analysis was limited to SU/SD operating conditions and did not include normal operation. The combined cycle unit SU/SD BACT analysis, performed in accordance with the EPA prescribed 'top-down' process, is documented below.

<u>Step 1 – Identify all Control Options</u>

The following technologies were identified as potentially available for controlling startup/shutdown emissions from the NHGC combustion turbines. Available technologies are listed in order from most to least effective (i.e., top down).

- Catalytic Control with Good Engineering Practices
    - Selective Catalytic Reduction for Nitrogen Oxides (NOx)

    - Oxidation Catalyst Control for Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)
- Pre-heater (to reduce startup duration)
- Good Engineering Practices

Each of these control methodologies is discussed separately below.

Catalytic Control with Good Engineering Practices – Uncontrolled emissions from a Siemens 501G with Heat Recovery Steam Generator (HRSG) combustion turbine follow a profile related to fuel flow, load, and temperature. During a startup, emissions increase, and then drastically decrease, as the unit ramps up to normal operating loads. During a startup, emissions are elevated as the combustion controls make adjustments for additional fuel firing while the unit proceeds to Final Mode operating conditions in the normal operating range of the unit. The NHGC combined cycle units reach Final Mode operating conditions at 50 to 100% operating range.

To further control emissions during startups, NHGC utilizes oxidation catalyst control for both carbon monoxide and volatile organic compounds (CO, VOC), plus selective catalytic reduction (SCR) for post-combustion control of nitrogen oxides (NOx). Oxidation catalyst efficiency is a function of catalyst temperature during startup, which is a directly related to combustion turbine exhaust gas temperature. The production of hot exhaust gas is controlled by the combustion dynamics of the turbine startup process and regulated by the process control system to ensure a safe and reliable startup. Below 500 degrees F, the post combustion removal efficiency for VOC is virtually zero, compared to the maximum removal efficiency of approximately 60%. CO removal efficiency is relatively higher than VOC during startup, but still well below the optimal/maximum control efficiency afforded by the catalytic oxidation systems during Final Mode operation.

The NHGC combined cycle units are equipped with SCR systems for post-combustion NOx emissions control. The SCR systems are designed not to inject ammonia until the temperature at the SCR catalyst is above 482 deg F. The current NHGC permit requires that the SCR be used when the catalyst temperature reaches 600 deg F, whereas the March 28, 2006 permit modification request includes an adjustment to allow for SCR activation at a lower catalyst temperature to minimize startup emissions.

Good Engineering Practice (GEP) relates to combined cycle unit operation and combustion control during startup/shutdown conditions designed to minimize such periods of elevated emissions to the extent possible within operational and safety constraints. Reaching Final Mode operation quickly, where the combustion controls are optimized for low emissions and catalyst temperatures are in the range necessary for optimal control, is the most effected work practice for minimizing emissions.

Pre-Heaters – In EPA Region IX, a few projects in the South Coast Air Quality Management District (SCAQMD) proposed the use pre-heaters (i.e., auxiliary boiler) to reduce NOx emissions during start-up, but all these facilities modified their permit requests to eliminate the use of pre-heaters prior to construction. The three facilities identified were the Magnolia Power Plant, the El Segundo Repower Project, and the Mountainview Power Project. The Magnolia Power Project and the Mountainview Power project have been constructed and both facilities were subject to review and approval by EPA Region IX without the need for additional emissions controls during SU/SD, beyond the use of a CO and NOx catalyst system. It should be noted that the addition of a pre-heater at NHGC would not be consistent with BACT, since the requirement would result in an overall increase in plant emissions.

Some combined cycle facilities at cogeneration plants utilize auxiliary boilers to supply steam to other facilities when the combustion turbines/HRSG are off line. The auxiliary boilers can also divert steam to the CT/HRSG to maintain higher temperatures in the HRSG, resulting in quicker startup times. In the case of NHGC, an auxiliary boiler would help to reduce startup times, and consequently startup emissions from the CT/HRSG, but it would result in the need for an additional emission source resulting in a net increase in plant emissions. The installation of a new major emissions source (not currently permitted) to minimize CT/HRSG emissions during startup would not be environmentally beneficial.

Good Engineering Practices – Many combined cycle facilities simply use SCR or steam injection for NOx control, with only GEP for control of CO and VOC emissions, i.e., no oxidation catalyst. The general concept of GEP was described above. NHGC already utilizes good engineering practices to minimize SU/SD emissions. NHGC also performs maintenance as suggested by manufacturer's recommendations and utilizes an onsite manufacturer's representative, when necessary, to oversee major plant maintenance activities and control enhancements.

Step 2 – Eliminate Technically Infeasible Control Options
Each of the identified control technologies is technically feasible.

Step 3 – Characterize Control Effectiveness of Technically Feasible Control Options
The top-ranked control option, GEP combined with catalytic oxidation and SCR was determined to constitute BACT during the initial HGP PSD permitting. This combination of work practice and control technology is capable of achieving the SU/SD emission rate limitations, including lb/hr and ton/yr limits, contained in Condition 18.A Tables 1 and 3 of the revised permit.

The second-ranked control option, involving the use of pre-heaters, could potentially lower emissions from the combined cycle units during startup if used in conjunction with the top ranked alternative; however, due to adverse environmental, energy and economic factors described in Step 4 below, the use of pre-heaters was not considered BACT. It is not relevant to discuss the use of GEP alone without add-on controls because the NHGC combined cycle units are already equipped with catalytic oxidation systems and SCR.

Step 4 – Evaluate More Effective Control Options
The top-ranked control option, GEP combined with catalytic oxidation and SCR was initially determined to be BACT for SU/SD operation of the NHGC combined cycle units. This control combination continues to represent best demonstrated industry performance for the source category. Energy, environmental, and economic impacts have been found to be acceptable in a large number of BACT determinations, including the initial NHGC permit.

In support of GEP to reduce startup time and emissions, Siemens engineers and NHGC developed new control logic for the HRSG high pressure steam controller that increased steam pressure faster than earlier designs. The increase in steam pressure elevated the exhaust gas temperature from the combustion turbine, thereby improving the rate at which the catalysts reach their minimum operating temperatures. This in conjunction with the beginning ammonia injection at a lower catalyst temperature results in reduced startup times and emissions.

Both the SCR and oxidation catalysts have been optimized and sized to fit in the HRSG of each unit. There is very limited space, and the addition of extra catalyst volume would have relatively insignificant effects. As discussed earlier, the effectiveness of the oxidation catalyst is driven by exhaust gas temperature, and additional catalyst would only serve to increase backpressure, requiring increased fuel combustion resulting in a reduction in plant efficiency (i.e., more emissions per megawatt of plant output).

Injecting ammonia for the SCR at the initiation of a startup would not be effective in reducing SU/SD emissions, since the catalytic reduction of NOx emissions occurs in a specific temperature range. Injecting ammonia at too low of a temperature (below the manufacturer's minimum recommended 482 deg F) would only serve to increase ammonia slip, and increase emissions of condensable particulate matter.

The second-ranked control option, involving the use of pre-heaters, would result in significant adverse environmental, energy and economic impacts. New emissions unit(s), e.g., heaters/boilers would have to be installed at the site, significantly increasing overall facility combustion-related emissions and energy use and involving prohibitive cost. MCAQD concluded that a detailed quantitative analysis of these adverse impacts was not warranted because it is not aware of any sources that have been required to install pre-heaters for the purpose of SU/SD BACT.

<u>Step 5 – Establish BACT</u>
The combination of oxidation catalysts for control of CO and VOC, SCR for NOx control, and GEP represents current BACT for startup/shutdowns and normal operation of combined cycle power plants. NHGC already employs this combination of work practice and control technology. The NOx, CO, and VOC emissions limitations applicable for SU/SD events contained in the revised draft permit (lb/hour and ton/yr, no change from current permit) in conjunction with revised SU/SD definitions were determined to be BACT for the NHGC combined cycle units in SU/SD and testing/tuning operating modes.

Ambient Impacts – Prior demonstrations of compliance with the National Ambient Air Quality Standards (NAAQS) were reviewed to confirm that the revised SU/SD-related permit conditions did not invalidate conclusions or necessitate further dispersion modeling demonstration(s). The initial HGP ambient air quality impact demonstration was contained in the original 2000 PSD permit application. This demonstration was updated as part of the March 26, 2003 minor permit modification including an increase in the allowable lb/hour and lb/event rate for CO emissions during startup. The 2003 demonstration focused specifically on CO emissions (1/hour and 8-hour averaging periods).

The pollutants affected by SU/SD and tuning/testing operating modes include NOx, CO, and VOC, each of which is subject to applicable BACT requirements. Of these pollutants, only NOx and CO were required to be evaluated for NAAQS compliance (i.e., in accordance with MCAQD modeling guidelines, no ozone modeling demonstration was required as part of initial permitting). The averaging period for the NOx NAAQS is annual. Allowable annual NOx emissions from the combined cycle units remain unchanged in the revised permit. Therefore, the permit revisions will not impact compliance status and the prior demonstration (indicating impacts below the PSD significant impact level [SIL]) remains valid.

Applicable averaging periods for the CO NAAQS are 1-hour and 8-hour. The revised permit will not affect the applicable lb/hr CO limit for SU/SD operation; therefore, the existing 2003 modeling demonstration indicating impacts below the PSD SIL remains valid. Removal of the lb/event CO limitation would theoretically increase potential 8-hour average CO emissions from the combined cycle units. Therefore, MCAQD elected to retain the lb/event limitation for CO emissions that was integral to the 2003 CO modeling demonstration for the 8-hour NAAQS (also indicating impacts below the PSD SIL). Air quality impact demonstrations and conclusions for NHGC are discussed in further detail in Section 20 of this TSD.

<u>Conclusion:</u>
Based on the foregoing analysis, MCAQD concluded that the proposed removal of annual SU/SD hour limitations for the combined cycle units and SU/SD event limitations (with the exception of CO) were justified and approvable. The existing lb/hr limitations for SU/SD will remain unchanged as well the ton/year limitations applicable to all operating scenarios. Current controls and work practices continue to meet BACT for SU/SD operation of the combined cycle units. Robust monitoring systems including CEMS for NOx and CO are in place to ensure compliance with concentration-based, lb/hr, and ton/yr BACT limitations.

The following changes were made to the permit SU/SD related requirements (except as noted, references refer to existing permit structure):

- Condition 18.A, Table 4 containing lb/event SU/SD limitations was removed;
- Condition 18.A, Table 1 (and associated conditions) were revised to identify the increased roll frequency for NOx and CO ton/yr limitations (i.e., a 365-day rolling total vs. 12-month rolling total);
- Condition 18.A, Table 3 was revised to incorporate the lb/event limitations for CO only previously contained in Table 4;
- The 700 hr/yr and 10 hr/calendar day SU/SD operational limits per combined cycle unit contained in Condition 19.B were removed;
- The definition of startup (Condition 19.B(2)(a) of the revised permit) was revised to incorporate a 5-hour maximum event duration (with noted exception);
- A new condition was added to Section 19.B requiring development of and conformance with a startup and shutdown plan for the combined cycle units and associated pollution control systems;
- The requirements to calculate monthly 12-month total hours of operation in each mode for each combined cycle unit contained in Condition 20.A was removed;
- Monitoring and recordkeeping requirements were revised to incorporate the missing data substitution procedures from 40 CFR Part 75 (NOx and CO); and
- Monitoring requirements were expanded to address monitoring and mass emission rate calculations procedures (based on 40 CFR Part 75) is greater detail, including the use of missing data substitution procedures from 40 CFR 75 Subpart D and Appendix C.

4.8 Increase in Allowable Cooling Water Total Dissolved Solids

<u>Requested Change:</u>
NHGC requested an increase in the allowable total dissolved solids (TDS) content of cooling tower recirculation water from 11,000 to 20,000 ppm. The reason for the request is water conservation. Increasing the allowable TDS concentration to 20,000 ppm will result in a significant reduction in annual water consumption in the cooling towers.

<u>Analysis:</u>
The NHGC cooling tower drift eliminator performance of 0.0003% is among the lowest currently reported BACT levels for the source category, demonstrating a superior level of drift

control in comparison to other facilities within the County and nationally. It is arguable whether the regulation of cooling water TDS as part of BACT is authorized or appropriate. However, given the existing limitation and correlation between TDS and PM10 emissions, MCAQD evaluated to the proposed change to ensure conformance with BACT and compliance with the existing ton/yr PM10 limit from the cooling towers.

Based on MCAQD guidance, NHCG updated the cooling tower PM10 emissions calculations to incorporate more recent and representative droplet size distribution data for high-efficiency drift eliminator controlled cooling towers.[4] As document in the calculation below, at 20,000 ppm TDS (mg/L TDS), the annual mass emissions per tower are 0.411 ton/year, for a plant total of 1.23 ton/year. This emission rate is well below the permitted allowable rate of 3.1 tons/yr per cooling tower and the rates modeled for NAAQS compliance demonstration.

Cooling Tower Emission Calculation

Cooling Tower Design Data				
Number of Cells per Tower		9		
Number of Towers		2		
Circulation Water Flow (per tower)	gpm	135,000		
TDS in Cooling Tower	mg/L	20,000		
Drift Emissions Factor	%	0.0003		
PM Emissions (per tower)	lb/hr	4.056		
PM Emissions (per cell)	lb/hr	0.451		
PM10 Emissions (per tower)	lb/hr	0.094		
PM10 Emissions (per cell)	lb/hr	0.010		
Operating Hours		8,760		
Annual PM-10 Emissions (per tower)	tons	0.411	per year	
Annual PM-10 Emissions (all towers)	tons	0.821	per year	
Exit Temperature	deg F	96		
Exit Diameter	ft	33.3		
Exit Height	ft	47		
Exit Flow Rate (per cell)	acfm	995,977	5.82	m/sec
			19.1	ft/sec

Notes: Drift emissions factor is percent of total circulation water flow
TDS - Total Dissolved Solids
PM - Total Particulate Matter PM10 = Particulates < 10 microns

Calculation (maximum condition):

Drift Rate per Tower

1.35E+05	gal water	8.345	lb	60	min	0.0003%	(drift)	=	203	lb water
1	min	1	gal water	1	hr					hr

PM Emissions per Tower

203	lb water	20,000	lb PM	=	4.056	lb PM	=	17.76	ton PM
1	hr	1E+6	lb water			hr			yr

PM10 Emissions per Tower

4.06	lb	0.023	lb PM10*	=	**0.094**	**lb PM10**	=	**0.411**	**ton PM10**
	hr		lb PM			**hr - tower**			**yr - tower**

* See size fraction calculation below

PM10 Emissions per Cell

0.09	lb PM10	1	tower	=	0.0104	lb	=	0.00131	g
	hr - tower	9	cells			hr - cell			sec - cell

PM10 Multiplier Calculation

			Reference
water TDS	20,000	ppm	Upper estimate
calcium carbonate density	2.7	g/cc	Perry's Chemical Engineer's Handbook, Sixth Edition, p. 3-10.
volume of a sphere	V = 4/3*PI*r3		

[4] Updated cooling tower PM-10 emissions calculations incorporate water droplet size distribution data from EPRI test data reported in the following reference: Joel Reisman and Gordon Frisbie: "Calculating Realistic PM10 Emissions from Cooling Towers" Greystone Environmental Consultants, Inc., Sacramento, CA.

Water Drop Size Distribution*

Droplet Dia. (micron)	% mass	% mass smaller	Water Droplet Vol. (cc)	Water Droplet Mass (g)	Solids Mass (g)	Solids Vol. (cc)	Solids Dia. (micron)	% mass <10 microns
10	0.00	0	5.2E-10	5.2E-10	1.0E-11	3.9E-12	1.9	
20	0.20	0.196	4.2E-09	4.2E-09	8.4E-11	3.1E-11	3.9	
30	0.03	0.226	1.4E-08	1.4E-08	2.8E-10	1.0E-10	5.8	
40	0.29	0.514	3.4E-08	3.4E-08	6.7E-10	2.5E-10	7.8	
50	1.29	1.806	6.5E-08	6.5E-08	1.3E-09	4.8E-10	9.7	
60	3.90	5.702	1.1E-07	1.1E-07	2.3E-09	8.4E-10	11.7	2.31
70	15.65	21.348	1.8E-07	1.8E-07	3.6E-09	1.3E-09	13.6	
90	28.46	49.812	3.8E-07	3.8E-07	7.6E-09	2.8E-09	17.5	
110	20.70	70.509	7.0E-07	7.0E-07	1.4E-08	5.2E-09	21.4	
130	11.51	82.023	1.2E-06	1.2E-06	2.3E-08	8.5E-09	25.3	
150	5.99	88.012	1.8E-06	1.8E-06	3.5E-08	1.3E-08	29.2	
180	3.02	91.032	3.1E-06	3.1E-06	6.1E-08	2.3E-08	35.1	
210	1.44	92.468	4.8E-06	4.8E-06	9.7E-08	3.6E-08	40.9	
240	1.62	94.091	7.2E-06	7.2E-06	1.4E-07	5.4E-08	46.8	
270	0.60	94.689	1.0E-05	1.0E-05	2.1E-07	7.6E-08	52.6	
300	1.60	96.288	1.4E-05	1.4E-05	2.8E-07	1.0E-07	58.5	
350	0.72	97.011	2.2E-05	2.2E-05	4.5E-07	1.7E-07	68.2	
400	1.33	98.34	3.4E-05	3.4E-05	6.7E-07	2.5E-07	78.0	
450	0.73	99.071	4.8E-05	4.8E-05	9.5E-07	3.5E-07	87.7	
500	0.00	99.071	6.5E-05	6.5E-05	1.3E-06	4.8E-07	97.5	
600	0.93	100	1.1E-04	1.1E-04	2.3E-06	8.4E-07	117.0	
Total	100.0							

PM10/PM multiplier = 0.023

* Aull, 1999. Memorandum from R. Aull, Brentwood Industries to J. Reisman, Greystone, December 7, 1999

The derivation of the revised cooling tower conversion factor using the particle size multiplier from above and assuming 8760 operating hours/year of cooling tower operation is:

$$\text{Conversion Factor} = 60\frac{\text{min}}{\text{hr}} \times 8760\frac{\text{hr}}{\text{yr}} \times 3.785\frac{\text{L}}{\text{gal}} \times 2.2046\times10^{-6}\,\frac{\text{lb}}{\text{mg}} \times 0.000003\left(\begin{matrix}\text{Drift}\\ \text{Factor}\end{matrix}\right)$$

$$\times 0.023\left(\text{PM/PM10 Multiplier}\right) \times \frac{1\,\text{ton}}{2000\,\text{lb}}$$

$$= 1.513\times10^{-10}\left(\frac{\text{min} \bullet \text{L} \bullet \text{ton}}{\text{gal} \bullet \text{mg} \bullet \text{yr}}\right)$$

4.9 Additional Permit Revisions

In addition to the revisions requested by NHGC reviewed above, MCAQD made several changes to permit conditions to 1) correct errors, 2) incorporate newly applicable or revised regualatory requirements, 3) generally improve language to better or more completely incorporate/cite regulatory requirements, 4) streamline requirements where appropriate, and 5) meet MCAQD obejectives for consistency between County combined cycle power plant permits. Permit revisions initiated by MCAQD are summarized in the table below:

Change	**Basis**
GENERAL PERMIT CONDITIONS	
Entire section updated.	General Permit Conditions were updated based on the current MCAQD template.
SPECIFIC PERMIT CONDITIONS	
18. ALLOWABLE EMISSION LIMITS	
Section 18 was reorganized. Table 'notes' were moved to appropriate permit Sections, e.g., Section 19: Operational Requirements or Section 20: Monitoring and Recordkeeping.	Many essential permit provisions were contained in notes to Section 18 emission limit tables. This format was inappropriate and confusing. Table note provisions were moved to appropriate sections of the permit. Section 18 was organized to clearly present emission limitations for each category of equipment, i.e., combined cycle units, cooling towers, firewater pump engine and emergency generator, and generally applicable limits.
Emission limit expression and averaging times were clarified.	Where missing or incorrect, emission limit expression and applicable averaging times were specified in Tables 1 through 5.
NOx and CO ton/year limitations revised from rolling 12-month total to rolling 365-day total basis.	This change was made in conjunction with SU/SD condition-related permit revisions requested by NHGC. The revision serves to enhance the enforceability of annual (ton/yr) emission limits applicable to all operating modes, including SU/SD. See Section 4.7 of this TSD for further discussion.
Opacity requirements were revised to more accurately reflect County Rule 300 and 324 requirements.	Existing permit language was not directly consistent with the underlying regulations. Language was revised accordingly.
Federal BACT regulatory citation [40 CFR 52.21(j)] added to BACT conditions	The MCAQD PSD program is delegated, therefore, both the requirements of County Rule 240 §380 and 40 CFR 52.21 are applicable.
Citation: ARS §49-106, State Rule R18-2-719.C.1 (R9-3-519.C.1) was removed from the fuel burning equipment PM limit applicable to the firewater pump engine and emergency generator.	SIP Rule 31.H.1.a is applicable and specifies the same equation-based limit. Reference to the State rule is unnecessary and redundant.
Several other minor corrections were made to regulatory citations.	N/A
19. OPERATIONAL REQUIREMENTS	
Section 19 was reorganized to incorporate operational requirements previously contained in Section 18 table notes. Operational requirements for CEMS (existing permit Condition 19.G) were moved to Section 20: Monitoring and Recordkeeping.	Permit provisions were organized under most appropriate headings.
The fuel restriction permit condition (Condition 19.A.1 of current permit and 19.B.1 of revised permit) was revised to incorporate a 0.005 gr/dscf sulfur restriction on natural gas calculated	Limit is required to ensure PSD-minor status for sulfuric acid mist emissions. See Section 9.2.2 of this TSD.

Change	**Basis**
on a 12-month rolling average.	
The general operational requirements of 40 CFR 60.11(d) were incorporated in new condition 19.B.3.	The requirements of 40 CFR 60.11(d) are applicable to the combined cycle units as NSPS Subpart GG affected facilities.
New condition 19.B.4 was added requiring the development and maintenance of a startup and shutdown plan for the combined cycle units and associated pollution control systems.	This change was made in conjunction with SU/SD condition-related permit revisions requested by NHGC. The revision serves to enhance the enforceability of BACT work practices during SU/SD operating conditions.
SCR and oxidation catalyst system O&M plans were incorporated in Appendix D of the revised permit and referenced as such in corresponding Section 19 permit conditions.	The O&M plans are being made enforceable under the revised permit while facilitating potential plan revision without requiring permit reopening.
Condition 19.F was revised to incorporate a 500 hour/yr limitation on operation of the firewater pump engine and emergency generator.	The previous permit did not contain any specific annual operating limitation. The 500 hour/yr limit is consistent EPA guidance on limiting potential to emit from emergency use IC engines.
Several corrections were made to regulatory citations.	N/A
20. MONITORING AND RECORDKEEPING REQUIREMENTS	
Monitoring requirements previously contained in Condition 19.G: Operational Requirements for CEMS were incorporated into Section 20.	CEMS requirements more appropriately belong under Monitoring and Recordkeeping vs. Operational Requirements.
Permit conditions specifying CEMS requirements were added/revised to more accurately and completely reference the requirements of 40 CFR 60 and 40 CFR 75, as applicable.	Under the streamlined NOx monitoring provisions, the NOx and diluent CEMS must meet the requirements of 40 CFR 75, except as noted. CEMS meeting the requirements 40 CFR 60.13 and Appendices B & F of 40 CFR Part 60 are used to demonstrate compliance with CO BACT limitations.
The missing data substitution procedures of 40 CFR 75 Subpart D were incorporated for NOx and CO monitoring.	The 40 CFR Part 75 missing data substitution procedures provide a consistent and technically justified means of accounting for emissions during periods of monitoring system downtime or unreliability. This approach will enhance compliance demonstration with ton/year BACT emissions limitations. The permit also provides the option of assuming emissions equal applicable lb/hr permit limitations.
Mass emission rate calculation procedures for NOx, CO, and SO_2 were incorporated based on the provisions of 40 CFR Part 75.	Explicit mass emission rate calculation procedures were incorporated into the revised permit to avoid ambiguity.
The ASTM methods contained in the custom fuel monitoring schedule for natural gas sulfur content were updated.	ASTM fuel sulfur analysis methods were updated to correspond with NSPS Subpart GG as revised July 2004.
References to CAM (40 CFR Part 64) were removed; CAM is not applicable to any units/pollutants at NHGC.	See Section 12.5 of this TSD.
Obsolete monitoring conditions associated with	Permit terms linked to initial startup and

Change	**Basis**
initial startup and testing of the combined cycle units were removed.	commencement of commercial operation of the combined cycle units are no longer relevant.
Monitoring and recordkeeping requirements for the firewater pump engine and emergency generator were expanded to comport with County Rule 324 requirements.	The requirements of County Rule 324 §502.1 and §502.4 applicable to the emergency use engines and were incorporated more completely into the permit.
New template language for visible emissions (opacity) monitoring and recordkeeping was incorporated.	The new visible emissions monitoring and recordkeeping requirements reflect current MCAQD template language for implementing County Rule 300 requirements.
Several corrections were made to regulatory citations.	N/A
A new condition was added providing for a 90 day transition to new monitoring requirements contained in the permit.	A transition period is necessary to allow for software reprogramming and implementation/shakedown of new monitoring approaches/procedures. During the transition, the Permittee must continue to comply with the monitoring requirements of the previous permit.
21. REPORTING REQUIREMENTS	
Obsolete reporting conditions associated with construction, initial startup, and testing of the combined cycle units were removed.	Permit terms linked to construction, initial startup and commencement of commercial operation of the combined cycle units are no longer relevant.
New Condition 21.C was added requiring 24-hour notice prior to the conduct of any tuning or testing activities on the combined cycle units.	See Section 4.4 of this TSD.
The Title V semiannual compliance and monitoring report requirements were revised and expanded based on current MCAQD policy.	MCAQD developed new standard reporting provisions combining the compliance certification and monitoring reports (required under NSPS) into a single report to be submitted semiannually. The revised semiannual compliance certification and monitoring reporting requirements are contained in Section 21.D of the revised permit.
References to CAM (40 CFR Part 64) were removed; CAM is not applicable to any units/pollutants at NHGC.	See Section 12.5 of this TSD.
Several corrections were made to regulatory citations.	N/A
22. TESTING REQUIREMENTS	
Testing requirements for the combined cycle units were revised as follows (see Section 16 of this TSD for details): • Test operating conditions revised to provide flexibility (full load available on day of testing vs. 95-105% nameplate) • NOx and CO testing requirements streamlined to coincide with 40 CFR Part 75 and Part 60 RATA provisions • Optional reduced load condition testing for	The revised testing provisions reflect current MCAQD guidelines for combined cycle plants. HAP testing (formaldehyde and hexane) has been added to confirm minor source status under CAA Section 112. Based on published emission factors, there is a possibility that HAP emissions could exceed major source thresholds.

Change	**Basis**
PM-10, VOC, and ammonia (subject to approval as part of pre-test protocol) • Ammonia test method CTM-027 specified • Ammonia testing frequency revised to every 3 years (also required within 90 days of complete SCR catalyst replacement) • New testing requirements for formaldehyde and hexane	
24. PERMIT CONDITIONS FOR SURFACE COATING OPERATIONS AS SUPPORT ACTIVITIES FOR THIS FACILITY	
Section 24 was removed from the permit.	The previous permit stated that no surface coating activities other than architectural coatings shall occur. MCAQD elected to remove the condition altogether and renumber the remaining conditions.
26. PERMIT CONDITIONS FOR DUST GENERATING OPERATIONS	
Section 26 was substantially revised and is contained in Section 25 of the revised permit due to renumbering.	Revised dust generating operation permit conditions reflect the current MCAQD template.
27. PERMIT CONDITIONS FOR ABRASIVE BLASTING WITH OR WITHOUT A BAGHOUSE	
Section 27 was substantially revised and is contained in Section 26 of the revised permit due to renumbering.	Revised to reflect County Rule 312 revision (7/2/2003).
28. PERMIT CONDITIONS FOR SURFACE COLD DEGREASERS AS SUPPORT ACTIVITIES FOR THIS FACILITY 29. PERMIT CONDITIONS FOR WIPE CLEANING	
These conditions were combined in to new Condition 27 incorporating County Rule 331 requirements for cold cleaners and wipe cleaning.	The previous permit contained only wipe cleaning provisions and stated that the Permittee shall not conduct cold degreasing subject County Rule 331. NHGC does operate a solvent-based batch cold cleaner. The unit does not qualify as an insignificant activity per Appendix D of the County Air Quality Rules. Therefore, a new section was added containing County Rule 331 requirements applicable to cold cleaners and solvent wipe cleaning. See Section 12.13 of this TSD for further information.
31. PERMIT CONDITIONS FOR VOLATILE ORGANIC COMPOUNDS	
Section 31 was removed from the permit.	The previous permit stated that no activities subject to County Rule 330 shall occur at the facility. MCAQD elected to remove the condition altogether.
APPENDIX A – MAJOR EQUIPMENT LIST	
The NHGC major equipment list was updated.	Updates reflect current information as presented in the NHGC renewal/significant revision permit application.
APPENDIX B – INSIGNIFICANT ACTIVITIES	
New Appendix B was added listing qualifying insignificant activities and bases.	A listing of insignificant activities is standard with MCAQD issued Title V permits.
APPENDIX C – PERMIT SHIELD APPLICABLE REQUIREMENTS	
New Appendix C was added listing permit shield	A listing of permit shield applicable requirements is

Change	Basis
applicable requirements.	standard with MCAQD issued Title V permits.
APPENDIX D – SCR and CATALYTIC OXIDATION SYSTEM O&M PLANS	
New Appendix D was added containing currently approved versions of the SCR and CAT-OX O&M plans.	See discussion under 19 – Operational Requirements, above.

5. SOURCE DESCRIPTION

The Harquahala Generating Project (HGP) is a combined-cycle electric generating plant with a nominal capacity of 1,060 MW owned and operated by New Harquahala Generating Company, LLC (NHGC). The plant is located in western Maricopa County, Arizona, near Tonopah, approximately 75 km west of Phoenix. The primary equipment at the plant consists of three combined-cycle power blocks, each consisting of a Siemens-Westinghouse 501G natural gas-fired combustion turbine generator (CTG) rated at 240 MW (nominal) and heat recovery steam generator (HRSG). Steam from the HRSG is admitted into a condensing reheat steam turbine generator (STG), one for each power block or a "one-on-one" design layout. The total net output for each unit, with CGT evaporative cooling, is approximately 353 MW, making the total net output for the three-unit facility 1,060 MW (nominal).

Additional emitting equipment and facilities at the plant include two mechanical-draft cooling towers, two emergency diesel engines, and three fuel storage tanks as identified in Section 6 below.

6. REGULATED ACTIVITIES

Emitting equipment and facilities at NHGC are identified in the table below.

1.	**Three Combined Cycle Units (CTG 1, CTG 2 and CTG 3) each with a common reheat condensing steam turbine and electrical generator.**
	Each Combined Cycle Unit consists of the following:
a.	Siemens-Westinghouse 501G combustion turbine operating in combined-cycle mode with a nameplate rating of 240 megawatts electric and fueled by pipeline quality natural gas only with steam injection power augmentation capability.
b.	Reheat condensing steam turbine (121 MW).
c.	Selective Catalytic Reduction (SCR) nitrogen oxides emissions control system for treating the Combustion Turbine exhaust.
d.	Oxidation Catalyst System for controlling carbon monoxide emissions from the Combustion Turbine exhaust.
e.	Continuous emissions monitor (CEM) system that records at least oxides of nitrogen (NOx), carbon monoxide (CO), and oxygen (O_2) content of the System exhaust.
f.	Exhaust stack with height 180 feet above plant grade and inside diameter of 19 feet.
2.	**Wet Cooling Towers**
a.	Two nine-cell wet cooling towers, with each cell rated at 15,000 gallons per minute recirculation rate (135,000 gallons per minute total for each cooling tower) and height 47 feet above plant grade.
b.	Continuous cooling water conductivity monitoring system.
3.	**Emergency Diesel Engines**
a.	One 450 horsepower diesel-fueled engine to drive the firewater pump.

b.	One 1,500 kilowatt diesel-fueled emergency generator to provide power to lube oil pumps and critical project systems.
3.	**Fuel Storage Tanks**
a.	One 500 gallon vehicle diesel fuel storage tank.
b.	One 500 gallon fire pump diesel fuel storage tank.
c.	One 240 gallon vehicle gasoline storage tank.
4.	**Other**
a.	Chemical storage equipment (See Section 7 of this TSD)
b.	Petroleum storage tanks (See Section 7 of this TSD)
c.	One batch solvent cold cleaning machine (non-vapor)

7. INSIGNIFICANT ACTIVITIES

Insignificant activities meeting qualifying criteria of County Rule 100 (definition) and Appendix D are listed in Appendix B of the revised permit. NHGC insignificant activities and qualification bases are documented in the table below.

Chemical Storage			
Description & Storage Location	**Name of Chemical Substance**	**Area in Which Material is Used**	**Qualifying Basis (a)**
Two 1,550 Gal Above Ground Tanks Located West of Cooling Tower A and East of Cooling Tower B	Depositrol (phosphoric acid) BL 5323	Cooling Tower	SD - ITEM 7.
The tank is located south of the gas compressor building	Ammonia 60,000 gallon storage tank (<20% as ammonia)	SCR Catalyst in HRSG	SD - ITEM 5.
1,000 gal. Tank in Zero Liquid Discharge area	Calcium Chloride (38%)	Water Treatment	SD - ITEM 2.
Two 1,550 Gal Above Ground Tanks Located West of Cooling Tower A and East of Cooling Tower B	Flogard POT 6100	Cooling Tower	SD - ITEM 2.
3,000 gal. Tank in Zero Liquid Discharge area	Klaraide PC1192	Water Treatment	SD - ITEM 2.
Two 8,500 Gal Above Ground Tanks Located West of Cooling Tower A and East of Cooling Tower B.	Liquichlor (12% Sodium Hypochlorite, sodium hydroxide and sodium chloride)	Cooling Towers	SD - ITEM 2.
10,000 gal. Tank in Zero Liquid Discharge area	Magnesium chloride (30%)	Water Treatment	SD - ITEM 2.
One 2,000 gal tank in US Filter area	Sodium Hypochlorite (12.5%)	Water Treatment	SD - ITEM 2.
Gas Compression (2 compressors, each hold 660 gallons)	Compressor oil	Gas Compressor	MISC - ITEM 5.
19 transformers located throughout site	Dielectric Fluid in Non-PCB Transformers	19 transformers located throughout site	MISC - ITEM 5.

Switchyard and Transformer Breakers445 lb. Container Total	SF_6 (Sulfur Hexafluoride)	Switch Yard	MISC – ITEM 5.
280 Gal tote in Zero Liquid Discharge	Kleen mtc 103	Zero Liquid Discharge	SD - ITEM 2.
Two 8,000 Gal Above Ground Tanks Located West of Cooling Tower A and East of Cooling Tower B; One 250 Gal tank in the USF skid.	Sulfuric Acid	Cooling Towers and water treatment	SD - ITEM 7.
Zero Liquid Discharge Area - 280 Gallon tote Container Size	Biomate MBC781	Zero Liquid Discharge	SD - ITEM 2.
Two 300 Gal Totes	Caustic Soda (33%)	Water Treatment	SD - ITEM 2.
Three 180 gal. Totes	Control OS 5035 (hydrazine)	HRSGs	SD - ITEM 2.
300 gal. Tote in Zero Liquid Discharge area.	Evaporator Anti-scale Depositrol BL 5306	Water Treatment	SD - ITEM 2.
280 gal. Tote.	Hypersperse MDC150	Water Treatment	SD - ITEM 2.
Two 280 gal. Totes in US Filter Area	Optisperse HP3100 (phosphate) 560 gallons	Water Treatment	SD - ITEM 2.
280 gal. Tote in Zero Liquid Discharge area	Sodium Bisulfate	Water Treatment	SD - ITEM 2.
280 gal. Tote.	Sodium Bisulfate BetzDearBorn DCL 30	ZLD	SD – ITEM 2.
280 gal. Tote.	SoliSep MPT 150	Water Treatment	SD - ITEM 2.
Two 280 Gal Above Ground Tanks Located West of Cooling Tower A and East of Cooling Tower B	Spectrus NX1100 (Magnesium Nitrate and Magnesium Chloride)	Cooling Tower	SD - ITEM 2.
Three 180 gal. Totes	Steamate NA1321 (Aluminum Hydroxide 19%)	HRSGs	SD - ITEM 2.
280 gal. totes in Zero Liquid Discharge area	Foamtrol AF2230 (Oxirane/methoxirane polymer with butyl ether)	Zero Liquid Discharge	SD - ITEM 2.
Two 280 gal. Totes	Polyfloc AE 1125	Water Treatment	SD - ITEM 2.
280 gal. Tote	Polyfloc AE1125 (Isoparaffinic petroleum distillate)	Water Treatment	SD - ITEM 2.
400 gal. Tote	Polyfloc AE1701 (Isoparaffinic petroleum distillate and ammonium acetate)	Water Treatment	SD - ITEM 2.
Three 55 gal. Drums	Corrshield (Sodium molybdate and Sodium Nitrite)	Closed Cooling Water	SD - ITEM 2.

55 Gal. drum in Zero Liquid Discharge	Kleen mtc 511	Zero Liquid Discharge	SD - ITEM 2.
55 Gal. drum in Zero Liquid Discharge	Optisperse	Zero Liquid Discharge	SD - ITEM 2.
Petroleum Storage Tanks			
Tank Designation	**Description / Contents**	**Tank/Container Content (Gallons)**	**Qualifying Basis**
1	Emergency Diesel Generator AST / Diesel	1350 gallon	SD - ITEM 4.
2	Emergency Diesel Fire Pump AST / Diesel	500 gallon	SD - ITEM 4.
3	Diesel AST / Diesel	500 gallon diesel	SD - ITEM 4.
4	Gas Turbine Lube Oil Reservoir / Lube Oil	5,000 gallon (3 on-site)	SD - ITEM 2.
5	Steam Turbine Lube Oil Reservoir / Lube Oil	3,600 gallon (3 on-site)	SD - ITEM 2.
6	Gas Turbine Control Oil Reservoir / Lube Oil	100 gallon (3 on-site)	SD - ITEM 2.
7	Steam Turbine Hydraulic Oil Reservoir / Hydraulic Oil	200 gallon (3 on-site)	SD - ITEM 2.
8	Gas Turbine Starting Package Oil Reservoir / Oil	1,800 gallon (3 on-site)	SD - ITEM 2.
9	Oil-Water Separator / Oil; petroleum products	1,880 gallon (3 on-site)	SD - ITEM 2.
10	Used Oil Tank / Oil; petroleum products	385 gallon	SD - ITEM 2.
11	Main Transformer / Mineral Oil (Non-PCB)	25,620 gallon (3 on-site)	MISC - ITEM 5.
12	Auxiliary Transformer / Mineral Oil (Non-PCB)	2,715 gallon (3 on-site)	MISC - ITEM 5.
13	Oil Rack and Oil Cabinet Lube Oil and petroleum products	1,605 (55-gallon and smaller containers)	SD - ITEM 2.
Other Activities			
Designation	**Description**	**Qualifying Basis**	**Note(s)**
Laboratory Fume Hood	Hanson Model 3SA-47, 142 FPM Exhaust	LPP - ITEM 1.	
Power Washer	Small internal combustion (IC) engine < 50 hp	ICE - ITEM 2.	
Lime Storage Silo	Storage Silo controlled by fabric filter; Pneumatically loaded by truck - emissions generated only during loading; Maximum of 10 hours of operation per year.	Rule 100, Section 200.57 and Rule 200, Section 308.1(c)	(b)
Soda Ash Storage Silo	Storage Silo controlled by fabric filter; Pneumatically loaded by truck - emissions generated only during loading; Maximum of 10 hours of operation per year.	Rule 100, Section 200.57 and Rule 200, Section 308.1(c)	(b)

Table Notes:
(a) Reference to County Rules Appendix D – List of Insignificant Activities
(b) Each Silo has a fabric filter with a manufacturer's guarantee of 0.02 grains per dscf.
Each silo has a flow rate of 1,065 dscfm
0.02 = manufacturer guarantee outlet gr/dscf
1065 = dscfm
7000 = gr/lb
99.90% = bin filter control efficiency (assumed)
10 = hrs/yr operated (unloading)
Potential PM Emissions:
Controlled = 0.0009 tons/yr
Uncontrolled = 0.91 tons/yr

8. ALTERNATIVE OPERATING SCENARIOS

The permit application identifies only one operating scenario as described in Sections 5 and 6 of this document.

9. POTENTIAL EMISSIONS

9.1 Allowable Emission Rates

The table below presents the allowable annual emission rates for regulated air pollutants emitted by NHGC. These limits are federally enforceable; therefore, they establish the facility's potential to emit.

Potential to Emit (tons/year)					
Device	**NOx**	**CO**	**SO_2**	**PM-10**	**VOC**
Combined Cycle Unit CTG1	108	192	23	97	34
Combined Cycle Unit CTG2	108	192	23	97	34
Combined Cycle Unit CTG3	108	192	23	97	34
Cooling Tower 1	NA	NA	NA	3.1	NA
Cooling Tower 2	NA	NA	NA	3.1	NA
TOTAL	**324**	**576**	**69**	**297.2**	**102**

9.2 Potential Emissions for Other Units/Pollutants

Potential emissions for units/pollutants not subject to annual (ton/year) emissions limitations are presented below.

9.2.1 Firewater Pump Engine and Emergency Generator

Potential emissions from then Firewater Pump and Emergency Generator diesel-fired reciprocating internal combustion engines based on equipment design capacities, 500 hours per year operation, and AP-42 emission factors are summarized in the table below followed by detailed supporting calculations.

Potential to Emit (tons/year)					
Device	**NOx**	**CO**	**SO_2**	**PM-10**	**VOC**
Firewater Pump Engine	3.49	0.75	0.05	0.25	0.28
Emergency Generator	15.1	3.45	0.25	0.27	0.40

		Firewater	Emergency				
		Pump Engine	Generator	Units			
Engine design capacity			1500	kW			
		450	2510	bhp			
Fuel input			137	gal/hr			
Fuel heat input		3.15	18.8	MMBtu/hr			
Annual operation		500	500	hrs/yr			
Firewater pump engine PTE							
Pollutant	EF	Units	Ref.	Potential Emissions			
				lb/hr	tpy		
NOx	3.10E-02	lb/bhp-hr	1	1.40E+01	3.49E+00		
CO	6.68E-03	lb/bhp-hr	1	3.01E+00	7.52E-01		
SO2	4.05E-04	lb/bhp-hr	2 (a)	1.82E-01	4.55E-02		
PM-10	2.20E-03	lb/bhp-hr	1	9.90E-01	2.48E-01		
VOC	2.51E-03	lb/bhp-hr	1	1.13E+00	2.83E-01		
Emergency generator PTE						Total PTE for	
						both engines	
Pollutant	EF	Units	Ref.	Potential Emissions			
				lb/hr	tpy	lb/hr	tpy
NOx	2.40E-02	lb/bhp-hr	2	6.02E+01	1.51E+01	7.42E+01	1.85E+01
CO	5.50E-03	lb/bhp-hr	2	1.38E+01	3.45E+00	1.68E+01	4.20E+00
SO2	4.05E-04	lb/bhp-hr	2	1.02E+00	2.54E-01	1.20E+00	2.99E-01
PM-10	5.73E-02	lb/MMBtu	2	1.08E+00	2.69E-01	2.07E+00	5.16E-01
VOC	6.42E-04	lb/bhp-hr	2	1.61E+00	4.03E-01	2.74E+00	6.85E-01
References/notes							
1. EPA AP-42 Chapter 3.3; October, 1996.							
2. EPA AP-42 Chapter 3.4; October, 1996.							
(a) Reference 2 used because SO2 emission factor based on fuel sulfur is believed to be more accurate.							

9.2.2 Sulfuric Acid Mist

Potential emissions of sulfuric acid mist (H_2SO_4) were not quantified as part of the initial PSD permitting for NHGC. As part of the permit renewal, MCAQD required that H_2SO_4 emissions be quantified to confirm that the potential to emit for the facility was below the PSD significant emission rate threshold of 7 tons/year.

The table below documents the H_2SO_4 potential to emit calculation for the NHGC combustion turbines. As shown, potential emissions based on a maximum natural gas total sulfur content of 0.5 grains per 100 cubic feet (0.005 gr/scf), consistent with "pipeline natural gas" as defined in 40 CFR 72.2, and assuming continuous annual operation of the combustion turbines at full load, are 2.32 tons/year/turbine, or 6.97

tons/year total. Thus, the facility-wide potential to emit is less than the 7 ton/year PSD significant emission rate threshold.

The current NHGC permit limits natural gas sulfur concentration to less than or equal to 0.0075 gr/scf. The actual sulfur content of natural gas delivered to the site based on El Paso Corporation records for 2005 ranged from 0.08 to 0.25 gr/100 scf, substantially below the 0.5 gr/100 scf "pipeline natural gas" threshold. As documented in Sections 4.9 and 11.2 of this TSD, the revised permit contains a new requirement limiting natural gas sulfur content to less than or equal to 0.005 gr/scf, calculated as a 12-month rolling average. This requirement serves to make the facility-wide potential-to-emit for H_2SO_4 of less than 7 tons/yr enforceable.

NHGC H2SO4 PTE Calculation

Given:

	Fuel sulfur content	0.005	grains/scf (max. for pipline quality natural gas)
	Fuel density	0.0441	lb/scf
	S --> SO3 at CT exh.	0.75%	R. Kagolanu, Siemens Power Generation (< 1%)
	SO2 to SO3 at Oxid. Cat.	8.0%	Oxidation catalyst vendor (6% expected, < 8%)
	SO2 to SO3 for HRSG	0.75%	R. Kagolanu, Siemens Power Generation (< 1%)
	SO2 to SO3 for SCR Cat.	1.0%	Hitachi-Zosen (0.2% expected, < 1%)
	Reaction of ammonia slip to form NH3-S compounds	1.0%	Conservative engineering estimate (low)
	Molecular Wt of S	32	
	Molecular Wt of SO2	64	
	Molecular Wt of H2SO4	98	
	Ambient Temperature	59	deg F (conservative annual average temperature)
	Hours per year	8760	
	Fuel Flow (lb/hr)	103,960	100% load fuel flow

Calculated Values:

(A)	SO2 (lb/hr, assumes 100% conv.)	3.368	Worst case SO2 with no SO3 formation (see calc below)
(B)	SO2 (lb/hr, actual) at CT Exhaust	3.342	0.75% of the sulfur (A) is actually converted to SO3
(C)	SO2 (lb/hr, after oxidation catalyst)	3.075	8% of the sulfur from (B) is converted to SO3
(D)	SO2 (lb/hr, for HRSG effect)	3.052	0.75% of the sulfur (C) is converted to SO3
(E)	SO2 (lb/hr, for SCR effect)	3.021	1% of sulfur (D) is converted to SO3
(F)	SO2 available for conversion to H2SO4	0.346	Equivalent to (A) - (E)
(G)	H2SO4 (lb/hr)	0.5302	(F) * 98 (Mol. Wt. H2SO4)/64 (Mol. Wt. SO2)
(H)	H2SO4 reduction due to interaction with ammonia	0.0053	
(I)	H2SO4 (lb/hr) after reduction due to ammonia	0.5274	(G) - (H)
	H2SO4 (tons/year), max. per combustion turbine	**2.32**	(I) * 8760/2000
	H2SO4 (tons/year), max. for facility	6.97	

#(A) = grains S/scf * (1 lb/7000 grains) * (fuel flow, lb/hr) * (1/ lb/scf) * (Mol. Wt SO2/Mol. Wt S)

9.2.3 Hazardous Air Pollutants

Potential Hazardous Air Pollutant (HAP) emissions from the NHGC combustion turbines and emergency use engines are documented below based maximum operating rate and literature emission factors. For the combustion turbines, EPA AP-42 emission factors were used except for formaldehyde and hexane, where California Air Toxics Emission Factor (CATEF) database factors were supplemented. No emission factor for hexane is reported in the current version of AP-42 for gas turbines (Chapter 3.1; 4/2000). For formaldehyde, the CATEF emission factor representative of oxidation catalyst controlled emissions was considered more accurate than the AP-42 factor, representing uncontrolled emissions.

As documented in the table below, the maximum single HAP emission rate (hexane) is 6.82 tons/yr and total combined HAP emissions are 20.2 tons/yr. These potential emission rates are below the applicable major source thresholds of 10 and 25 tons/year for single and total combined HAP, respectively, specified in CAA Section 112 and 40 CFR Part 63. MCAQD has included additional HAP testing requirements in the revised permit to confirm emission rates and minor source status (see Section 16 of this TSD).

Combined Cycle Units					**Emergency**	**Total**	
Design heat input/CT	2371	MMBtu/hr	HHV @ 59 deg. F		**Engines**		
Total design heat input	7113	MMBtu/hr	Total for 3 units		(see below)		
	EF	Ref.	PTE		PTE	PTE	
Pollutant	(lb/MMBtu)		lb/hr	tpy	tpy	tpy	
1-3-Butadiene	4.30E-07	1	3.06E-03	1.34E-02	3.08E-05	1.34E-02	
Acetaldehyde	4.00E-05	1	2.85E-01	1.25E+00	7.22E-04	1.25E+00	
Acrolein	6.40E-06	1	4.55E-02	1.99E-01	1.10E-04	2.00E-01	
Benzene	1.20E-05	1	8.54E-02	3.74E-01	4.39E-03	3.78E-01	
Ethylbenzene	3.20E-05	1	2.28E-01	9.97E-01		9.97E-01	
Formaldehyde	1.12E-04	2	7.97E-01	3.49E+00	1.30E-03	3.49E+00	
Hexane	2.19E-04	2	1.56E+00	6.82E+00		6.82E+00	
Naphthalene	1.30E-06	1	9.25E-03	4.05E-02		4.05E-02	
POM	2.20E-06	1	1.56E-02	6.85E-02	1.13E-03	6.97E-02	
Propylene oxide	2.90E-05	1	2.06E-01	9.03E-01	1.51E-02	9.19E-01	
Toluene	1.30E-04	1	9.25E-01	4.05E+00	1.64E-03	4.05E+00	
Xylenes	6.40E-05	1	4.55E-01	1.99E+00	1.13E-03	2.00E+00	
TOTAL		3		2.02E+01	2.56E-02	2.02E+01	
MAX		4		6.82E+00	1.51E-02	6.82E+00	
References/notes							
1. EPA AP-42 Chapter 3.1, Table 3.1-3. EF for uncontrolled gas turbines. April 2000.							
2. California Air Toxics Emission Factor database (CATEF). Median EF for CatOx/SCR controlled gas turbines.							
3. Total from above minus Naphthalene (included in PAH/POM).							
4. Maximum emitted pollutant from above.							
Emergency Use Engines		Firewater	Emergency				
		Pump Engine	Generator	Units			
Engine design capacity			1500	kW			
		450	2510	bhp			
Fuel input			137	gal/hr			
Fuel heat input		3.15	18.8	MMBtu/hr			
Annual operation		500	500	hrs/yr			
Firewater pump engine PTE							
Pollutant	EF	Units	Ref.	Potential Emissions			
				lb/hr	tpy		
Benzene	9.33E-04	lb/MMBtu	1	2.94E-03	7.35E-04		
Toluene	4.09E-04	lb/MMBtu	1	1.29E-03	3.22E-04		
Xylenes	2.85E-04	lb/MMBtu	1	8.98E-04	2.24E-04		
Propylene	2.58E-03	lb/MMBtu	1	8.13E-03	2.03E-03		
1.3-Butadiene	3.91E-05	lb/MMBtu	1	1.23E-04	3.08E-05		
Formaldehyde	1.18E-03	lb/MMBtu	1	3.72E-03	9.29E-04		
Acetaldeyhde	7.67E-04	lb/MMBtu	1	2.42E-03	6.04E-04		
Acrolein	9.25E-05	lb/MMBtu	1	2.91E-04	7.28E-05		
POM	1.68E-04	lb/MMBtu	1	5.29E-04	1.32E-04		
Emergency generator PTE						Total PTE for	
						both engines	
Pollutant	EF	Units	Ref.	Potential Emissions			
				lb/hr	tpy	tpy	
Benzene	7.79E-04	lb/MMBtu	2	1.46E-02	3.65E-03	4.39E-03	
Toluene	2.81E-04	lb/MMBtu	2	5.27E-03	1.32E-03	1.64E-03	
Xylenes	1.93E-04	lb/MMBtu	2	3.62E-03	9.06E-04	1.13E-03	
Propylene	2.79E-03	lb/MMBtu	2	5.24E-02	1.31E-02	1.51E-02	
1.3-Butadiene						3.08E-05	
Formaldehyde	7.89E-05	lb/MMBtu	2	1.48E-03	3.70E-04	1.30E-03	
Acetaldeyhde	2.52E-05	lb/MMBtu	2	4.73E-04	1.18E-04	7.22E-04	
Acrolein	7.88E-06	lb/MMBtu	2	1.48E-04	3.70E-05	1.10E-04	
POM	2.12E-04	lb/MMBtu	2	3.98E-03	9.95E-04	1.13E-03	
						2.56E-02	Max. HAP
						1.51E-02	Total HAP
References/notes for emergency engine PTE calculations							
1. EPA AP-42 Chapter 3.3; October, 1996.							
2. EPA AP-42 Chapter 3.4; October, 1996.							
(a) Reference 2 used because SO2 emission factor based on fuel sulfur is believed to be more accurate.							

10. EMISSION LIMITS

10.1 Annual Emission Limits:

	Rolling 365-day Total Emission Limits (tons)		Rolling 12-month Total Emission Limits (tons)		
Device	**NOx**	**CO**	**SO_2**	**PM-10**	**VOC**
Combined Cycle Unit CTG1	108	192	23	97	34
Combined Cycle Unit CTG2	108	192	23	97	34
Combined Cycle Unit CTG3	108	192	23	97	34
Cooling Tower 1	NA	NA	NA	3.1	NA
Cooling Tower 2	NA	NA	NA	3.1	NA

No changes have been made to the annual (ton/yr) emission limits identified in the above table as part of this Title V permit renewal and significant revision. NOx and CO emission limits were revised to a 365-day rolling total basis from a 12-month rolling total to enhance enforceability.

10.2 Combined Cycle Unit Emission Limits During Normal Operation:

	Emission Limits (pounds per hour, 1-hour average)				
Device	**NOx**	**CO**	**SO_2**	**PM-10**	**VOC**
Combined Cycle Unit CTG1	25.0	37.0	5.8	24.0	7.8
Combined Cycle Unit CTG2	25.0	37.0	5.8	24.0	7.8
Combined Cycle Unit CTG3	25.0	37.0	5.8	24.0	7.8

	Emission Limits				
Device	**NOx**	**CO**	**PM-10 Total (Filterable plus Condensable)**	**VOC**	**Ammonia**
Each Combined Cycle Unit CTG1, CTG2 or CTG3 Exhaust	2.5 ppmvd corrected to 15% O_2 3-hour rolling average	10 ppmvd corrected to 15% O_2 3-hour rolling average	0.0143 lb/MMBtu 3-hour average	2.8 ppmvd corrected to 15% O_2 3-hour average	10 ppmvd corrected to 15% O_2 24-hour average

No changes were made to the hourly (lb/hr), concentration (ppm), or heat input (lb/MMBtu)-based emission limits identified in the above tables as part of this Title V permit renewal and significant revision. The averaging period was added to the lb/hour limits and lb/MMBtu limit for PM-10 for clarification. Concentration-based limits for VOC and ammonia were revised to a 3-hour average and 24-hour average, respectively from the prior rolling averages. Rolling is irrelevant because compliance is determined by periodic performance testing rather than continuous emissions monitoring. The revised permit specifies that for ammonia, compliance shall be determined as the average of three separate test runs each not less than one hour in duration as required by Condition 22.A. This allows the source to perform longer duration test runs (up to 8 hours) consistent with the averaging period while providing for practical enforceability.

10.3 Combined Cycle Unit Limits during Startup, Shutdown, Tuning, and Testing

		Emission Limits			
		Pounds per hour, 1-hour average			**Pounds per event**
Device	**Condition**	**NOx**	**CO**	**VOC**	**CO**
Combined Cycle Units 1-3	Cold Start	220	2,300	440	3,000
Combined Cycle Units 1-3	Warm/Hot Start/Shutdown	151	2,300	237	2,600
Combined Cycle Units 1-3	Tuning/Testing	151	2,300	237	2,600

As documented in Section 4.7 of this TSD, the lb/event limitations were removed for NOx and VOC but retained for CO as part of the renewal/significant permit revision. The NOx, CO, and VOC lb/hr hour and CO lb/event limitations for SU/SD operation of the combined cycle units remain unchanged from the previous permit.

10.4 Cooling Tower Emission limits

As shown in Section 9.1 of this TSD, each of the NHGC cooling towers is subject to a 3.1 ton/year BACT emission limit (12-month rolling total).

10.5 Firewater Pump Engine and Emergency Generator Emission Limits

The Firewater Pump Engine and Emergency Generator are each subject to a 20 percent opacity standard pursuant to County Rule 324 §303.

10.6 Generally Applicable Emission Limits

Generally applicable emission limitations include off-site sulfur oxide limits (SIP Rule 32.F), fuel burning PM limits (SIP Rule 31.H), opacity limits (County Rule 320 §300, SIP Rule 32.A), and general gaseous or odorous air contaminant limitations (SIP Rule 32.A). Permit conditions incorporating these requirements remain unchanged from the previous permit.

11. OPERATIONAL REQUIREMENTS

11.1 General Facility-wide Requirements

General facility-wide operational requirements associated with County Rule 320 (Odors and Gaseous Air Contaminants) and SIP Rule 32.D are incorporated in Condition 19.A of the revised permit. No changes to these requirements were made other than correcting regulatory references.

11.2 Operational Requirements for Combined Cycle Units

11.2.1 Fuel Restriction

The Combined Cycle Unit fuel restriction was revised to include a 0.005 gr/scf total sulfur content limit on natural gas, calculated as a 12-month rolling average and incorporate minor language corrections. The new sulfur content limit was imposed to make potential H_2SO_4 emissions enforceable at less than 7 tons/yr. The natural gas fuel restriction from the existing permit (total sulfur content $\leq$ 0.0075 gr/scf) was maintained. Revised Permit Condition 19.B.1 reads as follows:

The Permittee shall combust only pipeline natural gas in Combined Cycle Units CGT1, CGT2, and CGT3. The total sulfur content of the pipeline natural gas shall not exceed 0.0075 grains per standard cubic foot over any averaging period and 0.005 grains per standard cubic foot calculated as a 12-month rolling average.

11.2.2 Startup, Shutdown, Testing and Tuning Operating Conditions

Several changes were made to existing permit operational requirements related to startup, shutdown and testing/tuning operations. Specific changes and revised permit conditions are discussed in detail in Section 4 of this TSD.

11.2.3 NSPS General Provisions

New Permit Condition 19.B.3 was added citing the general operation and maintenance requirements of 40 CFR 60.11(d).

11.3 Operational Requirements for Selective Catalytic Reduction Emission Control Systems

Operational requirements for the Combined Cycle Unit SCR systems as contained in Condition 19.C of the revised permit are as follows:

- Requirement to install, operate, and maintain SCR systems on each Combined Cycle Unit.
- Requirement to maintain and comply with an Operations and Maintenance (O&M) plan (included in Appendix D of revised permit) for each SCR system.
- Control system design requirement limiting ammonia injection to catalyst inlet temperature range specified in the SCR O&M Plan.

11.4 Operational Requirements for Oxidation Catalyst Emission Control Systems

Operational requirements for the Combined Cycle Unit Oxidation Catalyst systems as contained in Condition 19.D of the revised permit are as follows:

- Requirement to install, operate, and maintain Oxidation Catalyst systems on each Combined Cycle Unit.
- Requirement to maintain and comply with an Operations and Maintenance (O&M) plan (included in Appendix D of revised permit) for each Oxidation Catalyst system.

11.5 Operational Requirements for Cooling Towers

Operational limits for the cooling towers as contained in Condition 19.E of the revised permit are as follows:

- Requirement that cooling towers be equipped and maintained with high efficiency drift eliminators certified by the cooling towers' vendor to achieve less than 0.0003 percent drift.
- Limitation on cooling water TDS to ≤ 20,000 ppm.

11.6 Operational Requirements for the Firewater Pump Engine and Emergency Generator

Operational limits for the Firewater Pump Engine and Emergency Generator as contained in Condition 19.F of the revised permit are as follows:

- Fuel restriction: diesel fuel with sulfur content ≤ 0.05 percent.
- Operation permitted only for emergency conditions or routine maintenance checks.
- Limitation on hours of operation (≤ 500 hours/yr) consistent with EPA policy on limiting potential to emit for emergency use equipment.

12. APPLICABLE REQUIREMENTS

12.1 Prevention of Significant Deterioration (PSD, 40 CFR 52.21 and County Rule 240 §308)

Maricopa County administers a delegated PSD program. Therefore, the provisions of both 40 CFR 52.21 and County Rule 240 §308 are applicable to new major sources or major modifications to existing major sources. NHGC is subject to permit requirements associated with PSD Best Available Control Technology (BACT, 40 CFR 52.21(j) and County Rule 240 §308.1a, d, & e). These permit requirements, including both emissions limitations and operational requirements (e.g., fuel sulfur limitations), are contained in Sections 18 and 19 of the revised permit, as identified in Sections 10 and 11 of this TSD. Monitoring/recordkeeping and reporting requirements associated with BACT permit are contained in Sections 20 and 21 of the revised permit. Except as noted in Section 4 of this TSD, BACT conditions and associated monitoring, recordkeeping and reporting contained in the revised permit are consistent with the original PSD/Title V permit issued to NHGC.

12.2 New Source Performance Standards (NSPS, 40 CFR 60)

12.2.1 Subpart GG – Standards of Performance for Stationary Gas Turbines

APPLICABILITY
NSPS Subpart GG (incorporated by reference at County Rule 360 §301.40) applies to stationary gas turbines with a peak input of 10 million BTU per hour or greater. The three NHGC combustion turbines, each with a peak heat input of 2,138 MMBtu/hour (LHV, 59 degrees F), meet the applicability provisions of Subpart GG.

NSPS Subpart GG has underdone significant revision since the original NHGC PSD/Title V permit was issued in 2001. Revisions to the federal rule were promulgated on July 8, 2004 and February 24, 2006.[5] The permit was revised to reflect the current version of NSPS Subpart GG (as of September 2006).

[5] See 69 FR 41360, July 8, 2004 and 71 FR 9457, February 24, 2006.

EMISSION LIMITATIONS AND STANDARDS

NOx (§60.332) – Emission limit calculated according to the following equation under §60.332(a)(1): STD = 0.0075 x (14.4/Y) + F

Where STD is the allowable ISO corrected NOx concentration (% by volume at 15% oxygen, dry basis)

Y = manufacturers rated heat rate at rated load (kilojoules per watt hour)

F is an optional allowance for fuel-bound nitrogen.

For the NHGC combustion turbines, Y ≈ 9.6 (2,292.2 GJ/240 MW), therefore STD = 0.01125 %, or 112 ppm @ 15 % oxygen.

The applicable NOx BACT limitation for the NHGC combined cycle units is 2.5 ppmvd, corrected to 15 percent oxygen on a 3-hour rolling average. This limit is far more stringent than the applicable NSPS limit. As described in Section 15 of this TSD, the BACT and NSPS NOx limitations were streamlined as part of the original PSD/Title V permit. The NSPS NOx limitation was subsumed by the more stringent BACT limitation.

SO_2 (§60.333) – Emission limit of 0.015 percent SO_2 by volume at 15 percent oxygen and on a dry basis or fuel (natural gas) limited to total sulfur content of 0.8 percent by weight (8000 ppmw).

The applicable SO_2 BACT limitation for the NHGC combined cycle units includes a natural gas total sulfur limitation of ≤ 0.0075 gr/scf. Assuming a natural gas density of 0.0441 lb/scf, this equates to 0.0024 percent or 24.3 ppmv. This fuel sulfur limit is far more stringent than the applicable NSPS requirement. As described in Section 15 of this TSD, the BACT and NSPS SO_2 fuel sulfur limitations were streamlined as part of the original PSD/Title V permit. The NSPS SO2 (fuel sulfur) limitation was subsumed by the more stringent BACT limitation.

MONITORING

Applicable monitoring requirements for NOx and SO_2 are specified in §60.334(c), (h), (i), and (j). NOx CEMS meeting the more rigorous requirements of 40 CFR Part 75 and 40 CFR Part 60 are used to demonstrate compliance with the streamlined NOx limits (2.5 ppmvd corrected to 15 percent oxygen, 3-hour rolling average). According to §60.334 (b)(3)(iii), a NOx CEMS installed for purposes of compliance with 40 CFR Part 75 may be used to meet the requirements of Subpart GG.

The NOx monitoring provisions contained in the revised permit are associated with the more stringent BACT limitation. Per EPA White Paper Number 2 guidance, monitoring, recordkeeping, and reporting associated with a streamlined (subsumed) limit is not required "unless reliance on that monitoring would diminish the ability to assure compliance with the streamlined requirement." As documented in Section 15 of this TSD, NOx monitoring requirements meet the streamlining safeguards and are at least as stringent as those required by the NSPS.

Fuel sulfur content monitoring: The current permit contains an approved custom fuel monitoring schedule in accordance with §60.334(h)(4). NHGC did not request removal of this schedule in favor of other NSPS monitoring options available in the current version of Subpart GG [according to §60.334(h)(3) a source may elect not to monitor the total sulfur content of the natural gas if it is demonstrated to meet the definition of natural gas (0.2 gr/scf)]. The more robust custom fuel monitoring schedule, used to demonstrate compliance with the BACT natural gas sulfur content limit and subsumed NSPS limit has been retained in the revised permit.

REPORTING
Excess emissions and monitor downtime reporting requirements under Subpart GG are specified in §60.334(j). As discussed above, the NHGC permit contains more stringent limitations for NOx and SO_2 (fuel sulfur content) associated with BACT. As part of the original PSD/Title V permitting process, monitoring and reporting requirements were streamlined (See Section 15 of this TSD). Streamlined reporting requirements for Combined Cycle Units are contained in Sections 16 and 21 of the revised permit.

TESTING
The initial performance test requirements of Subpart GG have been completed in accordance with §60.8 and §60.335. Ongoing periodic testing requirements are specified in Section 22 of the revised permit.

12.2.2 Subpart A – General Provisions

NSPS Subpart A (incorporated by reference at County Rule 360 §301.40) applies to each affected facility, as specified in the relevant source category NSPS. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance provisions. Because the NHGC combined cycle units are subject to NSPS Subpart GG, the provisions of Subpart A are applicable. However, some of these requirements have been subsumed by the streamlined permit conditions addressing BACT and NSPS.

Applicable requirements associated with NSPS Subpart A are referenced in Sections 19.B, 20.A, and 21.A of the revised permit.

12.3 Acid Rain Program (40 CFR 72 – 76, County Rule 371)

NHGC is subject to the acid rain requirements of Title IV of the CAA; specifically, 40 CFR 72 (Permits Regulation), 40 CFR 73 (Sulfur dioxide allowance system), and 40 CFR 75 (continuous emission monitoring). In accordance with acid rain program requirements, NHCG must hold sufficient annual SO_2 allowances (not less than the total annual emissions from the unit for the previous calendar year), perform continuous emission monitoring in accordance with 40 CFR 75, and conduct associated recordkeeping and reporting. The provisions of 40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program apply only to coal-fired units and therefore are not applicable to NHGC. The NHGC Phase II acid rain permit is incorporated by reference in the Title V permit.

12.4 Title V Permit Provisions (County Rule 210)

NHGC is a major stationary source subject to the Title V permit provisions of County Rule 210. This permit serves to both renew existing Permit Number V99-015 and incorporate a significant revision in accordance with County Rule 210 §406.

12.5 Compliance Assurance Monitoring (CAM, 40 CFR 64)

40 CFR Part 64 applies to each pollutant-specific emissions unit at a major source if the unit satisfies all of the following:

- The unit is subject to an emission standard for the pollutant other than an exempted emission limit or standard under 40 CFR §64.2(b)(1)
- The unit uses a control device to achieve compliance
- The unit has a pre-control potential emission greater than or equal to 100% of the major source threshold

The NHGC combined cycle units utilize SCR and oxidation catalyst systems to control NOx, CO, and VOC emissions, each of which is subject emission limitations/standards. Potential uncontrolled emissions of VOC from each unit are below the applicable major source threshold of 100 tons/yr; therefore CAM is not applicable.

34 tons/yr (allowable VOC emission rate per unit) / (Oxidation catalyst VOC control efficiency: 60%) = 57 tons/yr

For NOx and CO emissions, the Title V permit specifies the use of CEMS, which qualify as a "continuous compliance determination method" per the definition at 40 CFR 64.1. Therefore, in accordance with 40 CFR 64.2(b)(vi), CAM is not applicable to NOx and CO emissions from the combined cycle units.

12.6 County Rule 324 – Stationary Internal Combustion Engines

County Rule 324 rule was adopted on October 22, 2003; therefore, it was not included in the previous permit. Rule 324 applies to the NHGC firewater pump engine and emergency generator. The units are eligible for partial exemption in accordance with §§104.1 and 104.7. Requirements of Rule 324 applicable to the subject units include §§301, 303, 502.1, and 502.4 as outlined below.

- §301: Fuel sulfur content limit of 0.05%
- §303: 20% opacity limit
- Recordkeeping provisions of §§502.1 and 502.4, including:
  - Engine data records (engine combustion type, manufacturer, model, rated brake horsepower, serial number and location)
  - Annual hours of operation
  - Explanation of use

12.7 County Rule 320; SIP Rule 32 – Odors and Gaseous Air Contaminants

County Rule 320 and SIP Rule 32 contain generic requirements for limiting odors and gaseous air contaminants. Revised County Rule 320 (as of July 2, 2003) and SIP Rule 32.A have been incorporated into the permit. Requirements applicable to NHGC include: 1) the general requirement not to emit odors or gaseous air contaminants in such quantities or concentrations as to cause air pollution (County Rule 320 §300 and SIP Rule 32.A) and 2) general material containment requirements to limit leakage and evaporation of materials (County Rule 320 §302).

12.8 County Rule 300; SIP Rule 30 – General Visible Emissions/Opacity Limits

County Rule 300 and SIP Rule 30 include generally applicable requirements for visible emissions and opacity. County Rule 300 is locally enforceable only. There have been no changes to Rule 300 since issuance of the last Title V permit; the Rule was last revised on February 2, 2001. County Rule 300 and SIP Rule 30 specify opacity limitations of 20 percent and 40 percent, respectively, which apply to equipment not subject to source-specific opacity requirements. County Rule 300 and SIP Rule 30 limitations are referenced in Condition 18.D.3 of the revised permit.

New monitoring and recordkeeping provisions for generally applicable opacity standards are included in Section 20.D.1 of the revised permit. The Permittee is required to conduct a visual inspection of stack emissions from the combined cycle units and the cooling towers during each week that the equipment is operated more than 10 hours. The Permittee is required to conduct a monthly visual inspection of emissions from the firewater pump engine and emergency generator, during operation. If visible emissions, other than combined water, are observed, the Permittee must monitor emissions in accordance with EPA Method 9. Initial Method 9 readings shall be taken within 3 days of the visual emissions observation if the Permittee has not received either a compliance status notification or NOV regarding an opacity standard in the past 12 months or within one day if otherwise. If the emitting equipment is not operating on the day that the initial Method 9 opacity reading is required to be taken, then the initial Method 9 opacity reading shall be taken the next day that the emitting equipment is in operation. If the problem causing the visible emissions is corrected before the initial Method 9 opacity reading is required to be performed, and there are no visible emissions (excluding uncombined water) observed from the previously emitting equipment while the equipment is in normal operation, the Permittee shall not be required to conduct the Method 9 opacity readings.

Follow-up Method 9 readings shall be performed while emitting equipment is in standard mode operation in accordance with the following schedule:

(1) Daily:
- a) Except as provided in paragraph 3 below, a Method 9 opacity reading shall be conducted each day that the emitting equipment is operating until a minimum of 14 daily Method 9 readings have occurred.
- b) If the Method 9 opacity readings required by this Permit Condition are less than 20% for 14 consecutive days, the frequency of Method 9 opacity readings may be decreased to weekly, in accordance with paragraph 2 of this Permit Condition.

(2) Weekly:
- a) If the Permittee has obtained 14 consecutive daily Method 9 readings which do not exceed 20% opacity, the frequency of Method 9 readings may be decreased to once per week for any week in which the equipment is operated.
- b) If the opacity measured during a weekly Method 9 reading exceeds 20%, the frequency of Method 9 opacity readings shall revert to daily, in accordance with paragraph 1 of this Permit Condition.
- c) If the opacity measured during the required weekly Method 9 readings never exceeds 20%, the Permittee shall continue to obtain weekly opacity readings until the requirements of paragraph 3 of this Permit Condition are met.

(3) Cease Follow-up Method 9 Opacity Monitoring:

Regardless of the applicable monitoring schedule, follow-up Method 9 opacity readings may cease if the emitting equipment, while in its standard mode of operation, has no visible emissions, other than uncombined water, during every Method 9 opacity observation taken for two weeks.

12.9 SIP Rule 311 §304; SIP Rule 31.H – General Particulate Matter Limits for Fuel Burning Equipment

SIP Rule 31.H and SIP Rule 311 §304 contain process weight rate-based equations for determining allowable PM emission rate for fuel combustion sources. The equation applicable to fuel burning equipment with a heat input rating of 4,200 MMBtu/hr or less (shown below) results in an allowable emission rate for the NHGC combined cycle units of 401.7 lb PM /hour (per unit). This is significantly greater than the 24.0 lb/hour BACT PM-10 limitation; therefore, SIP Rule 31.H and SIP Rule 311 §304 are effectively subsumed by the BACT requirement.

$E = 1.02(Q)^{0.769}$
E = the maximum allowable PM emission rate in lb/hr
Q = the heat input in million Btu/hr

12.10 SIP Rule 32.F – Off-site Sulfur Oxide Emission Limits

SIP Rule 32.F establishes concentration limits for off-site impacts of sulfur oxides and sulfuric acid. These limitations for SO_2 are referenced in the revised permit and remain unchanged from the previous permit. The fuel sulfur content limit serves to limit the emissions of sulfur dioxide and therefore off-site impacts.

12.11 County Rule 310; SIP Rule 310; SIP Rule 31.A – Fugitive Dust Emissions

County Rule 310, SIP Rule 310, and SIP Rule 31.A contain requirements for fugitive dust generating operations. The NHGC permit was revised to incorporate new template permit language developed by MCAQD incorporating these requirements. The major elements of the fugitive dust provisions contained in Section 25 of the revised permit are summarized below:

1. Dust control plan required
The Permittee is required to submit a dust control plan and obtain approval from the Control Officer prior to commencing any dust generating operation. Procedures for plan revision are specified.

2. Allowable emissions
Visible fugitive dust emissions shall not exceed 20 percent opacity. Affirmative defense provisions for exceedances of the opacity limit during wind events are provided.

3. Operational Requirements
Operational requirements, including stabilization, control measures, and work practices are specified for unpaved haul/access roads, unpaved parking lots, open areas, vacant lots, disturbed areas, bulk material handling, and open storage piles.

4. Monitoring and Recordkeeping
Monitoring and recordkeeping requirements for fugitive dust generating activities include maintenance of a written log of actual application or implementation of control measures pursuant to the approved Dust Control Plan and specified test methods for opacity and stabilization observations.

5 Fugitive dust control measures

The revised permit contains 21 tables specifying fugitive dust control measures consistent with County Rule 310 requirements.

12.12 County Rule 312; SIP Rule 312 – Abrasive Blasting

Section 26 of the revised permit contains requirements for abrasive blasting consistent with County Rule 312 as revised 7/2/2003. In general, the requirements include a 20 percent opacity limitation, operational limitations, and control measures for abrasive blasting activities.

12.13 County Rule 331; SIP Rule 331 – Solvent Degreasing Operations

Section 27 of the revised permit contains requirements for cold degreasing and wipe cleaning activities. The previous permit did not contain Rule 331 requirements applicable to cold cleaning machines. During this permit review; MCAQD determined that NHGC does operate a batch solvent degreaser (cold cleaner) that does not qualify as an insignificant activity per Appendix D of the County Air Regulations. Therefore, the permit was revised to incorporate Rule 331 requirements applicable to cold cleaners and solvent wipe cleaning activities. In general, the permit contains the following requirements with respect to solvent degreasing equipment/operations:

1. Operational limitations
2. Solvent handling requirements
3. Equipment requirements for all cleaning machines
4. Operating and signage requirements for cleaning machines
5. Solvent specifications
6. Non-vapor cleaning machine requirements
7. Special non-vapor cleaning situations
8. Monitoring, recordkeeping, and reporting

12.14 County Rule 335; SIP Rule 335 – Architectural Coatings

Section 24 of the revised permit contains requirements for architectural coatings consistent with County Rule 335 and SIP Rule 335. These requirements and permit conditions remain unchanged from the previous permit. In general, the permit contains the following requirements with respect to architectural coatings:

1. Allowable specifications, including VOC content for various architectural coatings
2. Exemptions
3. Container labeling requirements
4. Equipment cleanup requirements
5. Recordkeeping, reporting, and testing

12.15 County Rule 340; SIP Rule 340 – Cutback and Emulsified Asphalt

Section 28 of the revised permit contains requirements for cutback and emulsified asphalt consistent with County Rule 340 and SIP Rule 340. These requirements and permit conditions remain unchanged from the previous permit. In general, the permit contains the following requirements with respect to the cutback and emulsified asphalt:

1. Asphalt VOC content limitations
2. Exclusions from VOC content limitations

3. Monitoring, recordkeeping, and testing

13. POTENTIALLY APPLICABLE REQUIREMENTS

13.1 Risk Management Plans (40 CFR 68)

According to the NHGC permit application, 40 CFR Part 68 is not applicable to the facility. The aqueous ammonia solution used for the combined cycle unit SCR systems and stored on site is less than 20 percent ammonia. Ammonia solutions with a concentration less than 20 percent are not subject to 112(r) RMP requirements in accordance with 40 CFR 68.130.

Future applicability 40 CFR 68 could be triggered if hazardous or flammable materials are stored above threshold quantities. The potentially applicable requirements of 40 CFR Part 68 are addressed in General Condition 6.C of the revised permit.

13.2 Stratospheric Ozone Protection

Stratospheric Ozone Protection requirements associated with 40 CFR Part 82 are potentially applicable to NHGC. These requirements are addressed in General Condition 6.D of the revised permit.

14. NONAPPLICABLE REQUIREMENTS

14.1 NSPS Subpart Da

NSPS Subpart Da contains Standards of Performance for Electric Utility Steam Generating Units meeting specified applicability criteria. The NHGC combined cycle unit heat recovery steam generators (HRSGs) are not equipped with supplemental duct firing. Therefore, in accordance with 40 CFR 60.40Da(b), NSPS Subpart Da is not applicable to NHGC.

14.2 NSPS Subpart KKKK

40 CFR 60 Subpart KKKK, NSPS for new combustion turbines, was promulgated on July 6, 2006 and applies to affected facilities which commence construction, modification or reconstruction after February 18, 2005. Because NHGC was constructed prior to this date and has not been re-constructed or “modified” subsequent to the NSPS applicability date, NSPS Subpart KKKK is not applicable.

14.3 MACT Subpart YYYY

National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Combustion Turbines were promulgated on March 5, 2004 at 40 CFR 63 Subpart YYYY (§§63.6080 – 63.6175).[6] The standards are applicable only to new or reconstructed units, and not existing units. Regardless, as documented herein, NHGC is no a major source of HAP emissions. Therefore, 40 CFR 63 Subpart YYYY is not applicable.

14.4 County Rule 322

[6] Note that on August 18, 2004 EPA issued a stay on the effectiveness of the standard for two subcategories, lean premix gas-fired turbines and diffusion flame gas-fired turbines pending potential delisting.

County Rule 322 applies to power plant operations for which construction commenced prior to May 10, 1996 per §102. NHGC was constructed after that date; therefore, Rule 322 is not applicable.

14.5 County Rule 323

County Rule 323 applies to each stationary gas turbine with a heat input at peak load equal to or greater than 2.9 Megawatts (MW) and each steam generating unit that has a maximum design rated heat input capacity of greater than 10 million Btu per hour or 2.9 MW. However, Rule 323, Section 103.7, provides an exemption for combustion equipment used in power plant operations for the purpose of supplying greater than one-third of the electricity to any utility power distribution system for sale. NHGC is operated for the purpose of providing electricity to a distribution system and is therefore exempt from Rule 323.

14.6 County Rule 245

County Rule 245, Continuous Source Emission Monitoring, does not apply to any source which is subject to a New Source Performance Standard (Section 306.1). The NHGC combined cycle units are subject to NSPS Subpart GG and are therefore not subject to Rule 245.

15. STREAMLINING

NSPS Subpart GG (incorporated by reference at County Rule 360 §301.40) applies to the NHGC combined cycle units. The standard contains NOx and SO2 emission limitations and associated monitoring, recordkeeping and reporting.

The applicable NSPS NOx emission limit is calculated based on following equation under §60.332(a)(1):

STD = 0.0075 x (14.4/Y) + F

Where:
STD = the allowable ISO corrected NOx concentration (% by volume at 15% oxygen, dry basis)
Y = manufacturers rated heat rate at rated load (kilojoules per watt hour)
F = optional allowance for fuel-bound nitrogen.

For the NHGC combustion turbines, Y ≈ 9.6 (2,292.2 GJ/240 MW), therefore STD = 0.01125 %, or 112 ppm @ 15 % oxygen.

The applicable NOx BACT limitation for the NHGC combined cycle units is 2.5 ppmvd, corrected to 15 percent oxygen on a 3-hour rolling average. This limit is far more stringent than the applicable NSPS limit. Therefore, the BACT and NSPS NOx limitations were streamlined as part of the original PSD/Title V permit. The NSPS NOx limitation was subsumed by the more stringent BACT limitation.

The applicable NSPS SO_2 limitation found under §60.333 is 0.015 percent SO_2 by volume at 15 percent oxygen and on a dry basis <u>or</u> fuel (natural gas) limited to total sulfur content of 0.8 percent by weight (8000 ppmw). The applicable SO_2 BACT limitation for the NHGC combined cycle units includes a natural gas total sulfur limitation of ≤ 0.0075 gr/scf. Assuming a natural gas density of 0.0441 lb/scf, this equates to 0.0024 percent or 24.3 ppmv. This fuel sulfur limit is far more stringent than the applicable NSPS requirement. Therefore, the BACT and NSPS SO_2 fuel sulfur limitations were streamlined as part of the original PSD/Title V permit. The NSPS SO_2 (fuel sulfur) limitation was subsumed by the more stringent BACT limitation.

In accordance with EPA's White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program, "monitoring, recordkeeping, and reporting requirements associated with the most stringent emissions requirement are presumed appropriate for use with the streamlined emissions limit, unless reliance on that monitoring would diminish the ability to assure compliance with the streamlined requirement." The monitoring, recordkeeping, and reporting requirements contained in the revised NHGC permit associated with the most stringent (BACT) NOx and SO_2 limitations meet this presumption. CEMS meeting the requirements of 40 CFR Part 75 are used for NOx monitoring. SO_2 (fuel sulfur content) monitoring is in accordance with the custom fuel monitoring schedule originally implemented pursuant to NSPS Subpart GG. Recordkeeping and reporting requirements for NOx and SO_2 contained in the revised permit are at least as stringent as those required by NSPS and meet EPA streamlining criteria.

16. TESTING

Rule 270 contains performance and compliance testing requirements and establishes requirements for testing criteria, conditions, and reporting of test results. Performance testing requirements are specified in Section 22 of the revised permit. Several changes have been made (initiated by MCAQD) as noted in Section 4.9 of this TSD.

County Rule 200 Section 309 has granted the Control Officer the authority to require emissions testing if other sources of information are determined to be inadequate and certain other findings are made. The Control Officer has determined that the information available is not adequate. In addition, the Control Officer has determined that:

a. The facility emits NOx, CO, PM-10, VOC, ammonia, and HAPs. The USEPA has determined that exposure to these pollutant can adversely affect human health.
b. The test methods to be used are as follows:
    In accordance with CEMS RATA requirements for NOx
    In accordance with CEMS RATA requirements for CO
    EPA Test Method 5 and 202 for PM-10
    EPA Test Method 25A and 18 for VOC
    EPA CTM-027 for ammonia
    EPA CTM-037 for formaldehyde
    Compendium Method TO-15 for hexane

   These are EPA approved test methods and have been shown to produce scientifically acceptable results. Test methods for specific HAPs to be tested are included in the permit.
c. EPA Test Method has been shown to be technically feasible.
d. EPA Test Method has been shown to be reasonably accurate
e. After examining the estimated cost of the test, the Department believes that the cost of a stack-sampling test of the control device performance is reasonable to determine the effectiveness of the control device, to establish a baseline of emissions, to avoid potential fines, to establish parametric monitoring, to demonstrate adequacy of a maintenance program on equipment or controls, to provide emissions rate information for possible future PSD/NSR modeling requirements and to establish emissions rate information for environmental justice purposes.

Specific testing requirements for the combined cycle units and frequencies contained in the revised permit are shown in the table below.

Device to be Tested and Operating Conditions	Pollutant	Method	Frequency
Each Combined Cycle Unit	NOx	RATA testing in accordance with Conditions 20.A.(3)(b), (c), and (i)	In accordance with RATA requirements
	CO	RATA testing in accordance with Conditions 20.A.(3)(d) and (i)	In accordance with RATA requirements
Each Combined Cycle Unit when operating either at full load available on the day of testing or at an alternative load level established and approved as part of the pretest protocol	PM_{10}	Method 201A and 202	Annual
	VOC	Method 25A and 18	Annual
	Ammonia	EPA Conditional Test Method CTM-027	Every 3 years, and within 90 days following complete SCR catalyst replacement
Each Combined Cycle Unit when operating at full load available on the day of testing	Formaldehyde	CTM-037 "Method for Measurement of Formaldehyde Emissions From Natural Gas-Fired Stationary Sources - Acetyl Acetone Derivitization Method"	One time, within 180 days after permit issuance
	Hexane	Compendium Method TO-15	

17. PERMIT SHIELD

A permit shield was granted in the previous permit and has been included in this permit for specific applicable requirements. Appendix C (new) of the revised permit contains a listing of permit shield applicable requirements.

18. COMPLIANCE PLAN

NHGC is operating under an order of abatement by consent (OAC Number V-0007-06-GLB). Issuance of this permit signifies the expiration of the effective period of the order.

19. HAP IMPACT ANALYSIS

This significant TV permit revision/renewal does not include any proposed increase in potential HAP emissions and does not trigger the requirement to perform a HAP ambient impact analysis. HAP impacts were addressed in the initial NHGC PSD/Title V permitting process and subsequent minor permit modification issued on June 18, 2002 (addition of steam augmentation). Dispersion modeling analyses associated with these prior permit actions demonstrated that potential emissions from the facility would not cause exceedances of the Arizona Ambient Air Quality Guidelines (AAAQGs).

20. AMBIENT AIR QUALITY IMPACT ANALYSIS

Ambient impacts of criteria pollutants were addressed in the initial NHGC PSD/Title V permitting process and subsequent minor permit modifications issued on June 18, 2002 (addition of steam augmentation) and March 26, 2003 (increase in allowable lb/hr and lb/event CO emission rate for combined cycle units). Although this significant TV permit revision/renewal does not include any proposed increase in criteria pollutant potential emissions, revisions to SU/SD related permit conditions were reviewed for potential dispersion modeling demonstration implications. Changes to SU/SD conditions potentially impacting ambient impacts include the removal of lb/event limitations for NOx and VOC and removal of the annual hours of SU/SD operation limitation.

Three pollutants are affected by SU/SD operating conditions, NOx, CO, and VOC. The applicable averaging time for the NOx NAAQS is annual. The revised permit maintains the existing ton/year NOx limitations for the combined cycle units. Potential annual NOx emissions will not increase as a result of the permit revision; therefore, no new modeling demonstration was required. As an ozone precursor, NOx impacts were initially assessed at the boundary of the then Phoenix Metro Area Ozone Non-attainment Area. This analysis was also based on annual potential NOx emissions. Therefore, for the same reasons cited above, no new modeling demonstration was required.

CO NAAQS averaging periods are 1-hour and 8-hour. The revised permit maintains the existing lb/hour CO limitations for the combined cycle units. Therefore, there will be no increase in potential lb/hour CO emissions and no new modeling demonstration was required. MCAQD determined that 8-hour average CO emissions would potentially be affected by the removal of lb/event SU/SD emission limits. Maximum 8-hour average CO emissions used in the most recent SU/SD scenario NAAQS modeling demonstration relied upon the 3,000 lb CO/event limit.[7] Removal of this requirement would result in an increase in theoretical (allowable) emissions over an 8-hour period, potentially invalidating the prior modeling demonstration. Therefore, the CO lb/event limitation was maintained in Section 18.A, Table 3 of the revised draft permit.

[7] Ambient impact analysis contained in NHGC minor permit modification application dated February 27, 2003.

Appendix A
Technical Support Document (Ambient Air Quality Impact Report and Engineering Analysis)
for Original PSD/Title V Permit