TECHNICAL SUPPORT DOCUMENT

TECHNICAL INFORMATION PRESENTED IN REVIEW OF AN
APPLICATION FOR A PART 70 OPERATING PERMIT

SUBMITTED BY

NEVADA POWER COMPANY dba NV ENERGY

for

CHUCK LENZIE GENERATING STATION

Part 70 Operating Permit Number: 1513
SIC Code - 4911: Electric Utility Services
NAICS Code – 221112: Fossil Fuel Electric Power Generation

Clark County
Department of Air Quality
Permitting Section

May, 2015

EXECUTIVE SUMMARY

The Chuck Lenzie Generating Station, owned by Nevada Power Company dba NV Energy (NPC), is located at 13605 Chuck Lenzie Court, Las Vegas, Nevada in the Garnet Valley airshed, hydrographic basin number 216. Hydrographic basin 216 is designated as attainment for all pollutants. Chuck Lenzie is classified as a Categorical Stationary Source, as defined by AQR 12.2.2(j)(1). Chuck Lenzie is a major stationary source for PM_{10}, NO_x, CO and VOC and it is a minor source for SO_2 and HAP. Chuck Lenzie is also a source of GHG emissions.

The source consists of four GE frame 7 gas fired combustion turbine generators (CTGs), four duct-fired heat recovery steam generators (HRSGs), two steam turbine generators, two auxiliary 44 MMBtu/hr boilers, two diesel emergency generators, one diesel fire pump, a 9.8 MMBtu/hr gas line preheater, 6 cooling towers, and associated ancillary equipment. The potential emissions for the source are shown in the table below for informational purposes:

Source PTE (tons per year)

	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP	GHG[1]
PTE	**502.70**	**502.70**	**552.95**	**1,441.02**	**86.70**	**203.81**	**9.28**	**5,018,325**
Major Stationary Source Thresholds (Categorical)	100	100	100	100	100	100	10/25	-

[1]GHG is expressed as CO_2e for information only.

The Clark County Department of Air Quality (Air Quality) has delegated authority to implement the requirement of the Part 70 operating permit program.

The current Part 70 Operating Permit was issued on October 20, 2009. The Title V renewal application was submitted on April 4, 2014. Based on information submitted by the applicant and a technical review performed by the Air Quality staff, the Air Quality proposes the issuance of a Part 70 Operating Permit to NPC's Chuck Lenzie Generating Station.

This Technical Support Document (TSD) accompanies the proposed Part 70 Operating Permit for Chuck Lenzie Generating Station.

TABLE OF CONTENTS

I. ACRONYMS

Table I-1: Acronyms and Abbreviations

Acronym	Term
AQR	Clark County Air Quality Regulations
ATC	Authority to Construct
CAAA	Clean Air Act, as amended
CEMS	Continuous Emissions Monitoring System
CFC	Chlorofluorocarbon
CFR	United States Code of Federal Regulations
CO	Carbon Monoxide
CTG	Combustion Turbine-Generator
DLN	Dry Low NO_x
EPA	United States Environmental Protection Agency
EU	Emission Unit
GHG	Greenhouse Gasses
HAP	Hazardous Air Pollutant
HAS	Harry Allen Station
HCFC	Hydrochlorofluorocarbon
HP	Horse Power
kW	kilowatt
LHV	Lower Heating Value
MMBtu	Millions of British Thermal Units
M/N	Model Number
MW	Megawatt
NAICS	North American Industry Classification System
NO_x	Nitrogen Oxides
NRS	Nevada Revised Statutes
NVE	NV Energy
PM_{10}	Particulate Matter less than 10 microns
ppm	Parts per Million
ppmvd	Parts per Million, Volumetric Dry
PTE	Potential to Emit
QA/AC	Quality Assurance/Quality Control
RATA	Relative Accuracy Test Audits
RMP	Risk Management Plan
scf	Standard Cubic Feet
SIC	Standard Industrial Classification
SIP	State Implementation Plan
S/N	Serial Number
SO_2	Sulfur Oxides
TCS	Toxic Chemical Substance
VOC	Volatile Organic Compound

II. SOURCE INFORMATION

A. General

Permittee	Nevada Power Company dba NV Energy Chuck Lenzie Generating Station
Mailing Address	6226 West Sahara Avenue, MS#30 Las Vegas, NV 89146
Contact	Kimberly Williams
Phone Number	(702) 402-2184
Fax Number	(702) 402-5132
Source Location	13605 Chuck Lenzie Court, Las Vegas, NV 89165
Hydrographic Area	216
Township, Range, Section	T18S, R63E, Section 15
SIC Code	4911 – Electric Services
NAICS	221112– Fossil Fuel Electric Power Generation

B. Description of Process

The Chuck Lenzie Generating Station (the Station) has four GE frame 7 gas-fired combustion turbine generators (CTGs), four duct-fired heat recovery steam generators (HRSGs), two steam turbine generators, two auxiliary 44 MMBtu/hr boilers, two diesel emergency generators, one diesel fire pump, 6 cooling towers with 4 cells each and associated ancillary equipment. The station is set up with two power blocks: Block 1 consists of CTG 1 and 2, and Block 2 consists of CTG 3 and 4. The CTGs can operate up to 24 hours per day, seven days per week, and 52 weeks per year.

The CTGs convert thermal energy produced by the combustion of natural gas into mechanical energy that drives the generator and turbine compressor. The nominal rating of each gas turbine is 168 MW, with each duct-fired HRSG adding a nominal 50 MW. The Station is designed to meet demands under both base load and peak demand situations with approximately 1,170 megawatts (MW) of net electrical power with duct firing and inlet air chilling. Under these conditions each CTG/HRSG/Steam Turbine combination provides approximately 292 MW.

The turbine combustion systems have state-of-the-art dry low-NO_X combustion burner technology that accurately controls fuel flow to maintain turbine load and minimize turbine emissions. Fuel for the CTGs and duct burners is exclusively pipeline natural gas.

Air is supplied to each gas turbine through an inlet air filter, inlet air chilling system, and associated air inlet ductwork. Downstream of the inlet air filters and the air chilling section, the air is compressed in the compressor section of the combustion turbine and then exits through the compressor discharge casing to the combustion chambers. Fuel is supplied to the combustion chambers where it is mixed with the compressed air and the mixture is ignited. The high-temperature, pressurized gas produced by the combustion section expands through the turbine blades, driving the electric generator and the gas turbine compressor.

Exhaust gas from the gas turbine is directed through internally insulated ductwork to the HRSG. Each HRSG includes duct burners to allow the combustion of natural gas in the HRSG. This additional fuel combustion is used to generate additional power during periods of increased demand. Steam generated in the HRSG is routed to the steam turbine generator (STG) for electric power generation.

The HRSG transfers heat from exhaust gases of the gas turbine to feedwater to produce steam for the steam turbine operation. The HRSG is designed and constructed to operate at the maximum exhaust gas flow and temperature ranges of the gas turbine. The exhaust gases exit to the atmosphere after leaving the HRSG, having already passed through an oxidation catalyst and selective catalytic reduction (SCR) system for CO and VOC, and NO_X emissions control, respectively.

Power cycle heat rejection consists of an air-cooled condenser and a condensate receiver tank. The condenser air removal system is powered by mechanical vacuum pumps or steam jet air ejectors. The air cooled condenser and its auxiliaries are designed to accept steam turbine bypass flow during unit startup.

The air-cooled condenser provides power cycle heat rejection by circulating air across air-cooled condenser to bundles. Auxiliary cooling water heat exchangers reject heat from auxiliary equipment through a closed-cycle cooling water system.

The auxiliary boilers are used to provide steam to the steam turbine seals prior to start-up. These boilers each operate a maximum of 6,000 hours per year.

The two emergency diesel generators will only be operated in the event of an emergency and for testing and maintenance). One diesel engine is included for emergency fire pump operation. Each diesel engine is expected to be tested once each week for one to two hours in duration and is unlimited in use during actual emergencies; therefore, the air quality assessment was based on a conservative estimate of 500 hours operation per year per EPA guidance.

The six cooling towers, with 4 cells each, are for the chillers.

The Station includes a continuous emissions monitoring system (CEMS) for each gas turbine/HRSG unit that samples, analyzes, and records the concentration of carbon monoxide, oxides of nitrogen, and diluent (oxygen/carbon dioxide) in the flue gas. The system generates a log of emissions data and provides alarm signals to the control room when the level of emissions exceeds preselected limits. The CEMS comply with 40 CFR 60 and 40 CFR 75 requirements.

The lime silo and a soda ash silo support a water hardness elimination system for the clarifier, and are classified as insignificant activities.

C. Permitting History

Table II-C-1: NSR Permits Issued to Chuck Lenzie Generating Station

Date Issued	Permit Number	Description
05/13/2009	ATC Modification 1, Amendment 4	Modification 1, Revision 4 revises PTE for EUs: A12, A13 and A14. Also this permit revision incorporates clarifying languages distinguishing source PTE and enforceable emission limits.
05/23/2007	ATC/OP Modification 1, Amendment 2	NPC requested the reduction of VOC emissions from this source's turbine/duct burner emission units. The original VOC limits from each of EUs: A01/A02, A03/A04, A05/A06 and A07/A08 were 20.02 pounds per hour and 87.70 tons per year. NPC proposed reduced VOC emissions from each of these turbine/duct burner units to 11.29 pounds per hour and 49.45 tons per year.
12/20/2006	ATC/OP Modification 1, Amendment 1	Addition of one ammonia tank with no emissions; update in start-up/shut-down description; clarification of emergency/upset/breakdown scenarios; and additional language regarding performance testing frequency requirement.
08/19/2005	ATC/OP Modification 1	Issuance of initial operating permit
01/10/2005	ATC Modification 1, Revision 1	Change of name and ownership from Duke Energy Moapa, LLC to Nevada Power Company (Chuck Lenzie Generating Station). This permit allows up to 180 days of limited operation after the first fire of turbine.
06/03/2004	ATC Modification 1	Addition of one diesel generator, one fire pump, one gas line heater and increase in hours of operation for the two auxiliary boilers.
06/01/2001	ATC Modification 0	Issuance of initial authority to construct

There were no NSR actions since the October 20, 2009, issuance of the last Title V Operating Permit. Prior Notification actions and 502B10 actions were incorporated as appropriate. Temporary actions were not incorporated because the associated equipment was removed.

Air Quality received the application for Title V Operating Permit renewal on April 4, 2014, and deemed it timely. The application was deemed complete on April 15, 2014. Along with the renewal request, the source requested the following changes to the Title V Operating Permit:

- "Remove the second diesel fire pump (EU A15) and the associated insignificant activity (one of the 350-gallon diesel storage tanks) from the Title V Permit. This pump and tank were never installed at the facility."

Discussion – This request has been honored. Air Quality has removed all references to EU A15 and adjusted emissions tables accordingly.

- "As outlined in the insignificant activities list in the section above (*sic – proposed in another part of the application*), please delete the two sealed-system ammonia storage tanks (formerly EUs A11 and A11A; exempt per 12.5.2.5(a)(20)) from Table III-A-1 List of Emission Units and add them to Table III-A-2 List of Categorically Exempt Emission Units."

  Discussion - This request has been honored. These units are sealed and since Air Quality no longer directly regulates ammonia emissions as a Toxic Chemical Substance (TCS), these units will be moved to the List of Insignificant Emission Units or Activities for that reason.

- "As outlined in the insignificant activities list in the section above (*sic – proposed in another part of the application*), please add the lime and soda ash storage silos exempt per 12.5.2.5(c) to Table III-A-2 List of Categorically Exempt Emission Units. Details of the exemption request are provided in Appendix I."

  Discussion – The applicant appears to have misinterpreted AQR 12.5.2.5(c) for this request. Air Quality implements this rule as meaning that no unit or activity over 2 tpy "will be considered" for being classified insignificant rather than all units or activities under 2 tpy "will be classified" insignificant. Units or activities under 2 tpy will be considered for classification as insignificant, but the classification will be evaluated on a case-by-case basis, without considering limits on throughput or hours of operation. The source submitted supplemental information that describes the controls on the silos as passive filter rather than baghouses as described in the Part 70 OP application. Air Quality calculates the 8,760 hours PTE for the lime and soda ash storage activity based on each load lasting less than an hour at a specified grain loading, is 1.94 tpy, but without an enforceable throughput limit, that value could be much higher, so normally this activity would not be considered insignificant. However, based on historical data, the actual emissions are so low that Air Quality will honor this request.

- "As outlined in the insignificant activities list in the section above (sic – proposed in another part of the application), please add the chiller and cooling water wet surface air coolers exempt per 12.5.2.5(c) to Table III-A-2 List of Categorically Exempt Emission Units. Details of the exemption request are provided in Appendix I."

  Discussion - The applicant appears to have misinterpreted AQR 12.5.2.5(c) for this request. Air Quality implements this rule as meaning that no unit or activity over 2 tpy "will be considered" for being classified insignificant rather than all units or activities under 2 tpy "will be classified" insignificant. Units or activities under 2 tpy will be considered for classification as insignificant, but the classification will be evaluated on a case-by-case basis, without considering limits on throughput or hours of operation. Typically, Air Quality would consider wet surface air coolers and cooling towers as a single activity. In this case, chiller cooling towers and wet surface air coolers can be *considered as separate "evaporative cooling activities" because the wet surface chillers were previously considered categorically exempt units under a previous AQR 12. Air Quality calculates the 8,760 PTE for the wet surface air coolers activity is 0.77 tpy. Therefore, this request will be honored and the units placed on the insignificant activities list.*

Air Quality calculates the 8,760 PTE for the cooling towers activity is 4.50 tpy (0.75 tpy each), therefore the activity cannot be considered insignificant units. The emissions do not trigger significance, so no controls analysis is required.

- "Update the recordkeeping requirements for internal combustion engines (EUs A12, A13, A14) from rolling 12-month to annual to be consistent with federal regulations (40 CFR Part 63, Subpart ZZZZ *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*.) This language is contained in permit conditions III.B.2.h, III.B.2.i and III.E.1.k."

  Discussion – This request has been honored. Air Quality has made this change. The record keeping will be on a monthly and annual basis, and the operational limits and reporting will be per year instead of a rolling any consecutive 12-month period basis.

- "Add conditions to the permit to incorporate applicability of EUs A12, A13, and A14 to 40 CFR Part 63, Subpart ZZZZ *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*. The engines are all "existing" emergency engines at an area source of HAPs and have limited applicability to the subpart. Specifically, update III.B.2.h to allow for 100 hours per year for testing and maintenance purposes. Also add 40 CFR 60 Subpart ZZZZ to the list of Applicable Requirements in Attachment 1 of the Title V Permit."

  Discussion – This request has been honored. Air Quality has updated the affected conditions and table to reflect the 40 CFR 63 Subpart ZZZZ requirements. The PTE was recalculated for 500 hours per EPA guidance and the testing and maintenance received a 100 hours per year operational limit.

- "Operation of emergency stationary engines during emergency situations is not limited in 40 CFR 63 subpart ZZZZ or 40 CFR 60 subpart IIII. The operating hours for these units in emergency situations are not intended to be limited in the air permit either. Therefore, NV Energy requests that the annual PTE for emergency engines not be identified as limits in the air permit. The creation of annual emission limits creates a de facto limit on emergency situation operating hours, which is not appropriate for these units. NV Energy requests the PTE for these units be noted as estimates only, based upon 500 hours of annual operation which has been identified in EPA guidance as a value that is expected to cover most situations."

  Discussion – This request has been honored. Air Quality has updated the affected conditions and table to reflect the 40 CFR 63 Subpart ZZZZ requirements. The PTE was *recalculated for 500 hours per EPA guidance and the testing and maintenance received a 100 hours per year operational limit.*

- "Add the *National Emission Standards for Area Sources: Industrial/Commercial/Institutional Boilers*, also referred to as the Boiler Generally Available Control Technology and codified in 40 CFR Part 63 Subpart JJJJJJ to the Permit Shield Table since it does not apply to the two existing auxiliary boilers (EUs A09 and A10) because they are fired on natural gas and the facility is an area source of HAPs. The natural gas-fired boilers are not subject to Subpart JJJJJJ per 40 CFR 63.11195 which states: "The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart. (e) A gas-fired boiler as defined in this subpart.""

  Discussion – This request to include in permit shield has not been honored. Air Quality concludes that if 40 CFR 63, Subpart JJJJJJ is not applicable to the source, it shall not be included in the Permit Shield in the permit.

- "Remove all permit conditions associated with ammonia as an air pollutant formerly regulated by Clark County DAQ, including the continuous emission monitoring requirements outlined in Condition III.C.1. Monitoring of ammonia slip is for process control and efficiency purposes and is not needed to ensure compliance with current regulations or limitations. Compliance with NOx limitations is monitored by the NOx CEMS and is unaffected by the NH_3 CEMS. Other affected permit conditions are III.B.3.d, III.E.1.c., III.E.1.g., and III.F.8. Other affected portions of the permit include the Executive Summary text and emissions table, as well as Table III-B-1, Table III-B-2, and Table III-B-4."

  Discussion – This request has been honored. Air Quality no longer regulates ammonia. On a case-by-case basis, the previously incorporated conditions regulating ammonia can be removed from operating permits. In this case, the source is not located in a populated area or near a source of emissions that could potentially react with ammonia, such as chlorine. Therefore, Air Quality will remove the permit conditions and limits that regulate ammonia. The source should retain monitoring and record keeping of ammonia slip in case ammonia is identified to be a $PM_{2.5}$ *precurser. This TSD will retain ammonia to document this change.*

- "Condition III.D.7 of the permit currently stipulates that performance tests be conducted on the gas line preheater (EU A16) within 5 years of the previous test. This unit was first tested when the facility was commissioned. This unit has operated less than an hour over the last three years and has not operated at all since 2010. The unit is currently not in use, but may be used in the future contingent on fuel gas conditions. In addition, when in use, the preheater does not operate at a steady state, rather its normal function is to cycle on and off. This fluctuating operation makes it very difficult to performance test, as performance testing is required to be conducted during steady state operation. Based on this, the unit's very infrequent use, and the fact that it is fired only on natural gas, NV Energy requests that subsequent performance testing requirements for the preheater be removed from the permit entirely."

Discussion – This request has been honored due to the limited use of the unit and historical performance test results. Air Quality modified these conditions to require testing only at the request of the Control Officer.

- "Condition III.D.1 of the permit currently requires Turbine Units 1 through 4 and associated duct burners to be performance tested for NOx, CO and VOC every 2 years. As shown in Appendix H, the last three sets of test results (6 years of data) indicate that the turbines have tested well below the permit limits for NOx, CO, and VOC. As a demonstrated history of emissions compliance has been established, NV Energy requests that this performance test frequency requirement be revised to every 5 years. The requested frequency of testing is consistent with other similar units permitted by DAQ, such as those at the Silverhawk Generating Station and the Walter M Higgins III Generating Station."

  Discussion – This request has been honored. Air Quality has removed the subsequent performance testing requirement in favor of compliance demonstration by the CEMS and associated RATA.

- "In addition to the request above regarding Condition III.D.1, NV Energy requests that the performance testing requirement for VOC be eliminated entirely since, in the original permitting, Best Achievable Control Technology for VOC was determined to be natural gas combustion. Therefore, performance testing should not be required. As further support for this request, the VOC test results provided in Appendix H demonstrate that VOC emissions are far below the permit limits."

  Discussion – See above.

- "Testing Condition III.D.1 requires performance testing every two years. NV Energy requests the performance testing language be updated to allow performance testing to be completed within 90 days of the anniversary date of the last performance test. This request is being made for each emission unit that has a performance testing requirement including Conditions III.D.1, III.D.4, III.D.7, and Table III.F.1."

  Discussion – This request has been partially honored. Subsequent testing for condition III-D-1 was removed. Condition III-D-4 and III-D-7 already say this. Table III-F-1 refers to the timing of the test report, not the timing of the test itself.

- "For simplicity, NV Energy requests that the 40 CFR 60 Subpart Da opacity text currently in the permit be replaced with a simple reference to opacity testing per this rule. Language is included in permit conditions III.C.2, III.D.2 and III.E.2.d"

  Discussion – This request has been honored. Air Quality changed this requirement from text to a reference the rule.

- "Please remove Clark County AQR Section 49 *Compliance Requirements for Boilers and Steam Generators* and associated requirements from the Title V Permit, including the performance testing requirement for the auxiliary boilers (EUs A09 and A10). This rule has been repealed and is, therefore, no longer applicable to the facility. Additionally, historical performance testing shows emissions far below the permit limit and these units as shown in Appendix H. This language is included in permit conditions III.C.4, III.D.4, III.D.5, III.E.2.a and Attachment 1."

Discussion – This request has been partly honored. Air Quality removed the references to AQR 49, however the requirements will remain based on the Air Quality Guideline for Source Testing (available on the ClarkCountyNV.gov website), with an AQR 12.5.2.6 citation.

- "Add Clark County AQR Section 13 *National Emission Standards for Hazardous Air Pollutants* to the list of Applicable Requirements in the Title V Permit. The Permit references the section, but it is not listed as an applicable regulation in Attachment 1."

  Discussion – This request has been honored. Air Quality has updated the Applicable Requirements tables of the TSD and Title V permit.

- "NV Energy requests that the HAP PTE for the turbines be based on the emission factors summarized in Table 4-5 (of the application) to be consistent with the emission factors used for turbines at other NV Energy facilities."

  Discussion – This request has been honored. Air Quality has made this update to the TSD. The emissions were reduced by using the provided emission factors, while classification did not change. The HAP table was deleted from the permit since HAP for area sources is no longer regulated by Air Quality.

- "NV Energy requests annual visible emissions observations on a plant-wide level, rather than the quarterly testing currently stipulated in Condition III.C.5. Annual visible emissions observations would be in line with the fact that the turbines are fueled with natural gas and the emergency engines have very limited operations. Furthermore, there are no federal requirements for visible emissions monitoring for any of these units."

  Discussion - This request has not been honored. Air Quality feels that a quarterly visual emission observation is needed to demonstrate compliance with AQR 26.1.1 which limits emissions from any emission unit to 20 percent opacity. This frequency is consistent with standing practice and other permits issued for natural-gas-fueled equipment and diesel-fired emergency engines.

- "NV Energy requests that the pollutant identified in Tables III.B-1 be corrected from sulfur oxides (SOx) to the regulated criteria pollutant sulfur dioxide (SO_2) specifically in the source PTE, Table III-B-1, III-B-2 and Condition III.B.3.f."

  Discussion – This request has been honored. Air Quality made this change to all occurrences in the TSD and permit.

NV Energy commented on the draft Part 70 OP stating that conditions limiting the combined hourly fuel flow limit for the turbines and duct burners as well as a combined electrical output limit (conditions III-B-2 e and f) were not needed because there was already a limit on the individual turbine and duct burner pair and already a limit on hourly heat input. Air Quality agrees that combined heat input and fuel input are related to the hourly limit on each pair and that electrical output for a given fuel input can vary with efficiency. In addition, CEMS are installed to monitor the NO_X and CO to demonstrate compliance with emission limits. Due to this, the aforementioned conditions may be appropriate to be removed and the condition that limits operation of each turbine/duct burner combination to 3,205 MMBtu/hr heat input relied upon to limit emissions. However, after further analysis, Air Quality decided to keep condition III-B-2-e in the permit because the source was not able to support its argument that there is no ATC requirements violated if the existing condition is removed. Air quality removed the condition III-B-2-f because the rated electric output listed for each turbine/duct burner combination already established maximum electric output for the plant, which is lower than the limit in condition III-B-2-f.

Air Quality requested model numbers and serial numbers for all internal combustion engines and the respective driven units in the permit. This information was provided by the source on May 28, 2014.

Table II-C-2: BACT Determinations for Chuck Lenzie Generating Station

EU	Description	BACT Technology	BACT Limit
A01/A02	292 MW natural gas-fired electric turbine generator, supplemental duct-firing	SCR, dry low- NO_X burners, oxidation catalyst, natural gas combustion	3.0 ppmvd NO_X on a 3-hour average at 15% O_2; 10 ppmvd CO on a 3-hour average at 15% O_2; 10 ppmvd NH_3 on a 3-hour average at 15% O_2; 7 ppmvd VOC on a 3-hour average at 15% O_2.
A03/A04	292 MW natural gas-fired electric turbine generator, supplemental duct-firing	SCR, dry low- NO_X burners, oxidation catalyst, natural gas combustion	3.0 ppmvd NO_X on a 3-hour average at 15% O_2; 10 ppmvd CO on a 3-hour average at 15% O_2; 10 ppmvd NH_3 on a 3-hour average at 15% O_2; 7 ppmvd VOC on a 3-hour average at 15% O_2.
A05/A06	292 MW natural gas-fired electric turbine generator, supplemental duct-firing	SCR, dry low- NO_X burners, oxidation catalyst, natural gas combustion	3.0 ppmvd NO_X on a 3-hour average at 15% O_2; 10 ppmvd CO on a 3-hour average at 15% O_2; 10 ppmvd NH_3 on a 3-hour average at 15% O_2; 7 ppmvd VOC on a 3-hour average at 15% O_2.
A07/A08	292 MW natural gas-fired electric turbine generator, supplemental duct-firing	SCR, dry low- NO_X burners, oxidation catalyst, natural gas combustion	3.0 ppmvd NO_X on a 3-hour average at 15% O_2; 10 ppmvd CO on a 3-hour average at 15% O_2; 10 ppmvd NH_3 on a 3-hour average at 15% O_2; 7 ppmvd VOC on a 3-hour average at 15% O_2.
A09	44.1 MMBtu/hour natural gas-fired auxiliary boiler	Good combustion practices	30 ppmvd NO_X on a 1-hour average at 3% O_2; 100 ppmvd CO on a 1-hour average at 3% O_2.
A10	44.1 MMBtu/hour natural gas-fired auxiliary boiler	Good combustion practices	30 ppmvd NO_X on a 1-hour average at 3% O_2; 100 ppmvd CO on a 1-hour average at 3% O_2.

D. Operating Scenario

The four (4) turbine units with duct-firing may operate up to 24 hours per day, seven (7) days per week, 52 weeks per year and 8,760 hours per year. Each turbine/duct burner combination shall be limited to 3,205 MMBtu/hr heat input on a lower heating value (LHV). Each duct burner shall be limited to 2,298 MMBtu/hr heat input (LHV). Maximum natural gas fuel flow rate for the combined four (4) turbine units and associated duct burners shall be limited to 421,336 pounds per hour. Maximum plant output shall not exceed 1,252,080 kW. Each of the two (2) 44.1

MMBtu/hr boilers may operate up to 6,000 hours per year and shall burn only natural gas. Each of the two (2) emergency diesel generators (EU: A12 and A13) may operate up to a total of 100 hours per year for testing and maintenance purposes only. The diesel fire pump (EU: A14) may operate up to 100 hours per year for testing and maintenance purposes only. The emergency generators and diesel fire pump shall burn only low sulfur (less than 0.05 percent) diesel fuel. The 9.8 MMBtu/hr gas line heater (EU: A16) shall combust only natural gas and is permitted to operate up to 8,760 hours per year.

E. Proposed Exemptions

There are no restrictions on the operation of the two diesel emergency generators or the fire pump during emergency situations.

III. EMISSIONS INFORMATION

A. Total Source Potential to Emit

The source potential to emit (PTE) for pollutants (Table III-A-1), as presented in the Part 70 Operating Permit application and its amendments, reflects the permitted potential to emit established in the May 13, 2009 ATC (Modification 1, Amendment 4) as revised by this Title V permit renewal.

Table III-A-1: Source PTE (tons per year)

PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP	GHG[1]	NH_3
502.70	502.70	552.95	1,441.02	86.70	203.81	9.28	5,018,325	346.00

[1]GHG is expressed as CO_2e for information only.

There was some prior confusion, based upon the language in the ATC/OP, regarding the intent to establish a source-wide cap on the PTE. The source has not applied for a source-wide emissions cap, nor does the applicable Clark County SIP regulations require one be established. The source-wide PTE is intended to establish the status of the source as Major for PM_{10}, NO_x, CO, VOC. This status is made enforceable by the enforceable emissions and operational limits placed upon the individual emissions units.

The source asked that all permit conditions associated with ammonia be removed as it is no longer regulated by Air Quality. The current Air Quality rules do not regulate toxic chemical substances, such as ammonia. Air Quality has determined that the source complied with the former permit conditions. The source is not located in a populated area and there are not chemical plants in the area that may react with ammonia slip. Therefore, the conditions are removed from this draft OP.

The PTE of the GHG pollutant (Table III-A-2) reflects the individual pollutants, as submitted by the source, and converted into tons per year, where applicable. This PTE is not a source-wide cap on the GHG PTE.

Table III-A-2: Source GHG PTE (tons per year)

CO_2	CH_4	N_2O
4,861,943.00	493.47	479.60

B. Equipment Description

The air emission source equipment and associated major equipment is listed below. The Station is configured into two (2) power blocks that are capable of operating independently. In addition, common support equipment exists to support the two (2) power blocks.

Power Block Equipment

1. Four General Electric 7FA (GE 7241 FA+e) combustion turbine generating units, configured into two blocks of two combustion turbine generating units each, with:
    a. Natural gas firing;
    b. Inlet air filters with filter cleaning system;
    c. Inlet air chilling system;
    d. Class DLN 2.6 Dry-low NO_X combustors;
    e. Fire detection and protection system;
    f. Hydrogen cooled General Electric 7FH2 electric generator; and
    g. Emission Units A01, A03, A05 and A07.
2. Four heat recovery steam generators (HRSG), each one on the exhaust of a gas turbine, with:
    a. 3-pressure boiler system, with single reheat;
    b. Multi-element duct burners, with burner management system;
    c. Selective catalytic reduction (SCR) system for NO_X control;
    d. Oxidizing catalyst system for controlling CO and VOC;
    e. Exhaust stack 170 feet tall and 18 feet in diameter, equipped with continuous emissions monitoring system (CEMS) for NO_X and CO; and
    f. Emission Units A02, A04, A06 and A08.
3. Two General Electric steam turbine generators, one for each power block, with:
    a. 3-pressure, single reheat, condensing configuration; and
    b. Hydrogen cooled electric generator.
4. Combustion inlet air chilling,with:
    a. six chiller modules, three per power block; and
    b. Six evaporative cooling towers with 4 cells each, three per power block.
5. Two air-cooled condensers, one for each power block, with:
    a. Fifty cells each;
    b. A-frame construction; and
    c. 80-foot deck height, approximately 130 foot overall height.

Common Support Equipment

1. Two auxiliary boilers, natural gas fired, 44.1 MMBtu/hr maximum heat input each, with 40’ tall and 3’ diameter exhaust stacks (Emission Unit Identification A09 and A10).
2. Two ammonia storage tanks, 19 percent aqueous ammonia, sealed system (former Emission Units A11 and A11a).
3. Two emergency generators, diesel fired, 600 kW each (Emission Units A12 and A13).
4. One 275 hp fire pump, diesel driven (Emission Unit Identification A14).
5. Fuel gas preheater, natural gas fired, 9.8 MMBtu/hr maximum heat input, with dual 25’ tall and 18” diameter exhaust stacks (Emission Unit A16).
6. Closed cooling water system, with:
    a. Two fin-fan air coolers; and
    b. Two wet- surface air coolers.

Miscellaneous Ancillary Equipment

1. Ancillary equipment as necessary to ensure efficient, safe and reliable operation:
    a. Administration and control room building;
    b. Warehouse and maintenance building;
    c. Water treatment building;
    d. Various water storage tanks;
    e. Various chemical storage tanks;
    f. Two diesel fuel storage tanks, 800 gallons each, for emergency generators;
    g. One diesel fuel storage tank, 350 gallons, for fire pump;
    h. Electrical switchyard;
    i. Wastewater evaporation ponds;
    j. Lime silo and soda ash silo; and
    k. Lube oil storage structure.

C. Emission Units and PTE

The following tables summarize the allowable limits for each emission unit.

Table III-C-1: Source Emission Units

EU	Description	Rating	Make	Model Number	Serial Number
A01	Unit #1, CTG electric turbine generator, natural gas	Nominal rating:168 MW (292 MW with supplemental duct firing); MEQ = 292	General Electric	7FA (7241 FA+e)	297756
A02	Duct-fired HRSG for Unit #1	2,298 MMBtu/hr			102105
A03	Unit #2, CTG electric turbine generator, natural gas	Nominal rating:168 MW (292 MW with supplemental duct firing); MEQ = 292	General Electric	7FA (7241 FA+e)	297757
A04	Duct-fired HRSG for Unit #2	2,298 MMBtu/hr			102106
A05	Unit #3, CTG electric turbine generator, natural gas	Nominal rating:168 MW (292 MW with supplemental duct firing); MEQ = 292	General Electric	7FA (7241 FA+e)	297758

EU	Description	Rating	Make	Model Number	Serial Number
A06	Duct-fired HRSG for Unit #3	2,298 MMBtu/hr			102107
A07	Unit #4, CTG electric turbine generator, natural gas	Nominal rating:168 MW (292 MW with supplemental duct firing); MEQ = 292	General Electric	7FA (7241 FA+e)	297759
A08	Duct-fired HRSG for Unit #4	2,298 MMBtu/hr			102108
A09	Auxiliary boiler	44.1 MMBtu/hr	Cleaver Brooks	CB1700750200	OL101697
A10	Auxiliary boiler	44.1 MMBtu/hr	Cleaver Brooks	CB1700750200	OL101698
A12	Emergency generator, diesel	600 kW	Caterpillar	3412	3FZ03533
		750 hp	Caterpillar	SR4	AGE00590
A13	Emergency generator, diesel	600 kW	Caterpillar	3412	3FZ03528
		750 hp	Caterpillar	SR4	AGE00587
A14	Diesel fire pump	None	Clarke	JDFP-06WA	101120-003-01-01 FTA 100-EL12N-A-AD-AM-AN-EE-J-T-X
		275 hp	John Deere	6081 Series	RG6081A146444

EU	Description	Rating	Make	Model Number	Serial Number
A16	Gas line preheater	9.8 MMBtu/hr	NATCO	None	EL2F38803-01
A19	Chiller Cooling Tower, 4 cells	9,834 gpm each	Baltimore Aircoil	33985A-V-4	U02521301
A20	Chiller Cooling Tower, 4 cells	9,834 gpm each	Baltimore Aircoil	33985A-V-4	U02521302
A21	Chiller Cooling Tower, 4 cells	9,834 gpm each	Baltimore Aircoil	33985A-V-4	U02521303
A22	Chiller Cooling Tower, 4 cells	9,834 gpm each	Baltimore Aircoil	33985A-V-4	U025215401
A23	Chiller Cooling Tower, 4 cells	9,834 gpm each	Baltimore Aircoil	33985A-V-4	U025215402
A24	Chiller Cooling Tower, 4 cells	9,834 gpm each	Baltimore Aircoil	33985A-V-4	U025215403

Table III-C-2: List of Insignificant Emission Units and Activities

One 350-gallon diesel storage tanks for diesel fire pumps
Two 800-gallon diesel storage tanks for emergency generators
Numerous lube oil sumps and vents
Two ammonia storage tanks, M/N: none, S/N: DKT02-1210 and DKT02-1211; sealed systems
Two, 2-celled, wet-surface air coolers, 5,040 gpm each cell, Niagara Blower Company, one for each power block, M/N: RWC38748-2F16, S/N: none
Mobile Combustion Sources
Station Maintenance Activities
Maintenance Shop Activities
Steam Cleaning Operations
Lime Silo with Filter
Soda Ash Silo with Filter

Table III-C-3: Potential to Emit of the Source

EU	CO		PM_{10}		$PM_{2.5}$		NO_X		VOC		SO_2		NH_3	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
A01/A02[1]	79.74	349.25	28.25	123.73	28.25	123.73	28.95	126.80	11.29	49.45	4.78	20.93	19.75	86.50
A03/A04[1]	79.74	349.25	28.25	123.73	28.25	123.73	28.95	126.80	11.29	49.45	4.78	20.93	19.75	86.50
A05/A06[1]	79.74	349.25	28.25	123.73	28.25	123.73	28.95	126.80	11.29	49.45	4.78	20.93	19.75	86.50
A07/A08[1]	79.74	349.25	28.25	123.73	28.25	123.73	28.95	126.80	11.29	49.45	4.78	20.93	19.75	86.50
Subtotal	318.96	1,397.00	113.00	494.92	113.00	494.92	115.80	507.20	45.16	197.80	19.12	83.72	79.00	346.00
A09[2]	6.40	19.20	0.40	1.20	0.40	1.20	5.20	15.60	0.80	2.40	0.40	1.20	0.00	0.00
A10[2]	6.40	19.20	0.40	1.20	0.40	1.20	5.20	15.60	0.80	2.40	0.40	1.20	0.00	0.00
A12[3,4]	4.12	1.03	0.68	0.17	0.68	0.17	14.57	3.64	0.53	0.13	0.30	0.08	0.00	0.00
A13[3,4]	4.12	1.03	0.68	0.17	0.68	0.17	14.57	3.64	0.53	0.13	0.30	0.08	0.00	0.00
A14[3,4]	1.84	0.46	0.61	0.15	0.61	0.15	8.53	2.13	0.69	0.17	0.10	0.03	0.00	0.00
A16	0.71	3.10	0.09	0.39	0.09	0.39	1.17	5.14	0.18	0.78	0.09	0.39	0.00	0.00
A19 through A24	0	0	1.03	4.50	1.03	4.50	0	0	0	0	0	0	0	0
Total	**342.55**	**1,441.02**	**116.89**	**502.70**	**116.89**	**502.70**	**165.04**	**552.95**	**48.69**	**203.81**	**20.71**	**86.70**	**79.00**	**346.00**

[1] Based on 0.75 grains sulfur per 100 scf of natural gas.
[2] Maximum operation based upon 6,000 hours per year.
[3] Based on 0.05 weight percent sulfur in the diesel fuel.
[4] Maximum operation based upon 500 total hours per year.

Table III-C-4: HAP Emissions

Chuck Lenzie Generating Station - HAP Annual Potential to Emit (tpy)								
Equipment ID	A01/A02; A03/A04;	A09	A10	A12	A13	A14	A16	Total Facility
Specific Source of Emissions	Combined Cycle Natural Gas Turbine (Turbine Units 1-4)	Auxiliary Boiler	Auxiliary Boiler	Emergency Diesel Generator	Emergency Diesel Generator	Diesel Emergency Fire Pump	Gas Line Preheater	
1,3-Butadiene	1.75E-02	—	—	5.50E-05	5.50E-05	1.88E-05	—	1.76E-02
Acetaldehyde	1.62E+00	—	—	3.55E-05	3.55E-05	3.69E-04	—	1.62E+00
Acrolein	2.60E-01	—	—	1.11E-05	1.11E-05	4.45E-05	—	2.60E-01
Benzene	5.28E-02	3.02E-04	3.02E-04	1.09E-03	1.09E-03	4.49E-04	9.81E-05	5.61E-02
Ethylbenzene	1.30E+00	—	—	—	—	—	—	1.30E+00
Formaldehyde	6.21E-01	1.08E-02	1.08E-02	1.11E-04	1.11E-04	5.68E-04	3.50E-03	6.47E-01
Naphthalene	5.28E-02	8.78E-05	8.78E-05	—	—	—	2.85E-05	5.30E-02
PAHs	8.93E-02	—	—	2.98E-04	2.98E-04	8.09E-05	—	9.00E-02
Propylene Oxide	1.18E+00	—	—	—	—	—	—	1.18E+00
Toluene	8.53E-01	4.90E-04	4.90E-04	3.95E-04	3.95E-04	1.97E-04	1.59E-04	8.55E-01
Xylenes	2.60E+00	—	—	2.72E-04	2.72E-04	1.37E-04	—	2.60E+00
2-Methylnaphthalene	—	3.46E-06	3.46E-06	—	—	—	1.12E-06	8.03E-06
3-Methylchloranthrene	—	2.59E-07	2.59E-07	—	—	—	8.41E-08	6.02E-07
7,12-Dimethylbenz(a)anthracene	—	2.30E-06	2.30E-06	—	—	—	7.47E-07	5.35E-06
Acenaphthene	—	2.59E-07	2.59E-07	—	—	—	8.41E-08	6.02E-07
Acenaphthylene	—	2.59E-07	2.59E-07	—	—	—	8.41E-08	6.02E-07
Anthracene	—	3.46E-07	3.46E-07	—	—	—	1.12E-07	8.03E-07
Benz(a)anthracene	—	2.59E-07	2.59E-07	—	—	—	8.41E-08	6.02E-07
Benzo(a)pyrene	—	1.73E-07	1.73E-07	—	—	—	5.61E-08	4.02E-07
Benzo(b)fluoranthene	—	2.59E-07	2.59E-07	—	—	—	8.41E-08	6.02E-07
Benzo(g,h,i)perylene	—	1.73E-07	1.73E-07	—	—	—	5.61E-08	4.02E-07
Benzo(k)fluoranthene	—	2.59E-07	2.59E-07	—	—	—	8.41E-08	6.02E-07
Chrysene	—	2.59E-07	2.59E-07	—	—	—	8.41E-08	6.02E-07
Dibenzo(a,h)anthracene	—	1.73E-07	1.73E-07	—	—	—	5.61E-08	4.02E-07
Dichlorobenzene	—	1.73E-04	1.73E-04	—	—	—	5.61E-05	4.02E-04
Fluoranthene	—	4.32E-07	4.32E-07	—	—	—	1.40E-07	1.00E-06
Fluorene	—	4.03E-07	4.03E-07	—	—	—	1.31E-07	9.37E-07
n-Hexane	—	2.59E-01	2.59E-01	—	—	—	8.41E-02	6.02E-01
Indeno(1,2,3-cd)pyrene	—	2.59E-07	2.59E-07	—	—	—	8.41E-08	6.02E-07
Phenanathrene	—	2.45E-06	2.45E-06	—	—	—	7.94E-07	5.69E-06
Pyrene	—	7.20E-07	7.20E-07	—	—	—	2.34E-07	1.67E-06
Arsenic	—	2.88E-05	2.88E-05	—	—	—	9.34E-06	6.69E-05
Beryllium	—	1.73E-06	1.73E-06	—	—	—	5.61E-07	4.02E-06
Cadmium	—	1.58E-04	1.58E-04	—	—	—	5.14E-05	3.68E-04
Chromium	—	2.02E-04	2.02E-04	—	—	—	6.54E-05	4.69E-04
Cobalt	—	1.21E-05	1.21E-05	—	—	—	3.92E-06	2.81E-05
Manganese	—	5.47E-05	5.47E-05	—	—	—	1.78E-05	1.27E-04
Mercury	—	3.74E-05	3.74E-05	—	—	—	1.21E-05	8.70E-05
Nickel	—	3.02E-04	3.02E-04	—	—	—	9.81E-05	7.03E-04
Selenium	—	3.46E-06	3.46E-06	—	—	—	1.12E-06	8.03E-06
Total	**8.64**	**0.27**	**0.27**	**2.27E-03**	**2.27E-03**	**1.86E-03**	**8.82E-02**	**9.28**

The HAP emissions in Table III-C-4 were calculated using AP-42 for the boilers and emergency engines. AP-42 was also used for the turbines and duct burners except for benzene, formaldehyde and toluene. The emissions for these three HAPs are taken from Gas-Fired Boiler and Turbine Air Toxics Summary Report, prepared by Carnot Technical Services, Tustin, California and the Electric Power Research Institute, December 1996. These HAP emission factors are consistent with those used for Clark Generating Station and Harry Allen Generating Station.

No single source-wide HAP emission exceeds ten (10) tons per year and total source-wide HAP emission does not exceed 25 tons per year. Therefore, this source is not subject to MACT for combustion turbines.

Table III-C-5: Enforceable Emission Limitations Excluding Startup and Shutdown (ppmvd)

EU	Emission Unit	CO	NO_X	VOC
A01[1]	Turbine Unit #1 with or without duct-firing	10	3.0	7.0
A03[1]	Turbine Unit #2 with or without duct-firing	10	3.0	7.0
A05[1]	Turbine Unit #3 with or without duct-firing	10	3.0	7.0

EU	Emission Unit	CO	NO_X	VOC
A07[1]	Turbine Unit #4 with or without duct-firing	10	3.0	7.0
A09[2]	Auxiliary 44.1 MMBtu/hr boiler	100	30	N/A
A10[2]	Auxiliary 44.1 MMBtu/hr boiler	100	30	N/A

[1] Limitations in ppmvd, 3-hour average @ 15% O_2.
[2] Limitations in ppmvd, 1-hour average @ 3% O_2.

D. Performance Testing and Continuous Emission Monitoring

Initial performance testing for the turbines, the auxiliary boilers and the gas heater were completed as follows: Turbines 1 and 2- 1/15/06, Turbine 3- 3/24/06, Turbine 4- 3/23/06, Auxiliary boiler (EU: A09)- 1/10/06, Auxiliary boiler (EU: A10)- 3/24/06 and fuel preheater (EU: A16) - 3/25/06. Any additional required testing will be performed using the following methods:

Table III-D-1: Performance Testing Protocol Requirements for Turbines/Duct Burners

Test Point	Pollutant	Method
Turbine/HRSG Exhaust Outlet Stack	PM_{10}	EPA Method 201/202 or 201A/202
Turbine/HRSG Exhaust Outlet Stack	NO_X	EPA Method 7E and Method 20
Turbine/HRSG Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Turbine/HRSG Exhaust Outlet Stack	VOC	EPA Method 18 or Method 25a
Turbine/HRSG Exhaust Outlet Stack	Opacity	EPA Method 9
Stack Gas Parameters	--	EPA Methods 1, 2, 3 and 4

Table III-D-2: Performance Testing Protocol Requirements for Auxiliary Boilers

Test Point	Pollutant	Method
Boiler Exhaust Outlet Stack	NO_X	EPA Method 7E
Boiler Exhaust Outlet Stack	CO	EPA Method 10
Stack Gas Parameters	--	EPA Methods 1, 2, 3A and 4

Table III-D-3: Performance Testing Protocol Requirements for the Gas Line Heater

Test Point	Pollutant	Method
Heater Exhaust Outlet Stack	NO_X	EPA Method 7E
Heater Exhaust Outlet Stack	CO	EPA Method 10
Stack Gas Parameters	--	EPA Methods 1, 2, 3A and 4

Annual RATA testing must be performed on each NO_X, CO, and O_2 Continuous Emissions Monitoring Systems (CEMS).

All performance tests on the turbine units and duct burners must conform to 40 CFR 60 Subparts A, Da and GG, and 40 CFR 72. All performance tests on the auxiliary boilers must conform to AQR 14 and Air Quality Guideline for Source Testing.

Air Quality has removed the subsequent testing for units covered by CEMS because the source has passed the initial and all previous testing.

Continuous Emissions Monitoring

Chuck Lenzie Generating Station is operating a NO_X and CO CEMS on each turbine unit. The CEMS monitor and record the following parameters for each individual CTG:

1. hours of operation;
2. electrical load;
3. fuel consumption and type;

4. exhaust gas flow rate (by direct or indirect methods);
5. exhaust gas concentration of NO_X, CO and O_2;
6. three hour average concentrations of NO_X, CO, and the mass flow rate of NO_X and CO; and
7. hourly, daily and quarterly accumulated mass emissions of NO_X and CO.

IV. REGULATORY REVIEW

A. Local Regulatory Requirements

Air Quality has determined that the following public law, statutes and associated regulations are applicable:

1. Clean Air Act, as amended (CAAA), Authority: 42 U.S.C. § 7401, et seq.;
2. Title 40 of the Code of Federal Regulations (CFR);
3. Nevada Revised Statutes (NRS), Chapter 445B;
4. Portions of the AQR that are included in the State Implementation Plan (SIP) for Clark County, Nevada. SIP requirements are federally enforceable. All requirements from Authority to Construct permits and Section 16 Operating Permits issued by Air Quality are federally enforceable because these permits were issued pursuant to SIP-included sections of the AQR; and
5. Portions of the AQR that are not included in the SIP. These locally applicable requirements are locally enforceable only.

The Nevada Revised Statutes (NRS) and the Clean Air Act Amendments (CAAA) are public laws that establish the general authority for the Regulations mentioned.

The Air Quality Part 70 (Title V) Program received Final Approval on November 30, 2001 with publication of that approval appearing in the Federal Register December 5, 2001 Vol. 66, No. 234. AQR Section 19 - Part 70 Operating Permits [Amended 07/01/04] details the Clark County Part 70 Operating Permit Program. On September 20, 2010, Clark County submitted a revision to the operating permit program (AQR 12.5) pursuant to 40 CFR Part 70.4(i)(2). EPA has not acted on that request yet. These regulations may be accessed on the Internet at: http://www.clarkcountynv.gov/depts/AirQuality/Pages/Rules_CurrentRulesandRegulations.aspx

Local regulations contain sections that are federally enforceable and sections that are locally enforceable only. Locally enforceable only rules have not been approved by EPA for inclusion into the State Implementation Plan (SIP). Requirements and conditions that appear in the Part 70 OP which are related only to non-SIP rules are notated as locally enforceable only.

Table IV-A-1: AQR Section 12 Summary Table for This Source

	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP	TCS[1] (NH_3)
Air Quality Area	Attainment	Attainment	Attainment	Attainment	Attainment	Attainment	N/A	N/A
Source PTE (tpy)	**502.70**	**502.70**	**552.95**	**1,441.02**	**86.70**	**203.81**	**9.28**	**346.00**

	PM_{10}	$PM_{2.5}$	NO_X	CO	SO_2	VOC	HAP	TCS[1] (NH_3)
Major Source (categorical)	≥ 100 tpy	≥ 100 tpy	≥ 100 tpy	≥ 100 tpy	≥ 100 tpy	≥ 100 tpy	≥ 10 tpy for each HAP, or ≥ 25 tpy for combined HAPs	N/A

[1] NH_3 is listed for information only.

Discussion: Chuck Lenzie Generating Station is a major stationary source of PM_{10}, $PM_{2.5}$, NO_X, CO, and VOC and a source of GHG. Air Quality no longer regulates ammonia. As part of the original New Source Review Analysis, all of these emissions triggered notice of proposed action. This proposed renewal will also trigger notice of proposed action.

All Applicable Air Quality Regulations are included in the attachment.

Increment Analysis

Discussion: Chuck Lenzie Generating Station is a major source in Hydrographic Area 216 (Garnet Valley). Permitted emission units include four turbines, two boilers, two generators, one fire pump, one preheater, and six cooling towers. Since minor source baseline dates for PM_{10} (December 31, 1980), NO_2 (January 24, 1991) and SO_2 (December 31, 1980) have been triggered, Prevention of Significant Deterioration (PSD) increment analysis is required.

Air Quality modeled the source using AERMOD to track the increment consumption. The average of 2012 and 2013 actual emissions were used in the model. Stack data submitted by the applicant were supplemented with information available for similar emission units. Five years (1999 to 2003) of meteorological data from the McCarran Station and Desert Rock Station were used in the model. United States Geological Survey (USGS) National Elevation Dataset (NED) terrain data was used to calculate elevations. Table IV-A-3 presents the results of the modeling.

Table IV-A-3: PSD Increment Consumption

Pollutant	Averaging Period	PSD Increment Consumption by the Source (μg/m³)	Location of Maximum Impact	
			UTM X (m)	UTM Y (m)
SO_2	3-hour	6.96[1]	686589	4028750
SO_2	24-hour	4.64[1]	686589	4028750
SO_2	Annual	1.25	686589	4028750
NO_X	Annual	8.70	686589	4028750
PM_{10}	24-hour	27.90[1]	686589	4028750
PM_{10}	Annual	8.17	686589	4028750

[1] Second High Concentration

Table IV-A-3 shows the location of the maximum impact and the potential PSD increment consumed by the source at that location. The impacts are below the PSD increment limits.

B. Federally Applicable Regulations

40 CFR 60-STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

Subpart A - General Provisions

40 CFR 60.7-Notification and record keeping

Discussion: This regulation requires notification to Air Quality of modifications, opacity testing, records of malfunctions of process equipment and/or continuous monitoring device, CEMS data, and performance test data. These requirements are found in the Part 70 OP in Sections II-C, III-E, and III-F. Air Quality requires records to be maintained for five years, a more stringent requirement than the two years required by 40 CFR 60.7.

40 CFR 60.8-Performance tests

Discussion: These requirements are found in the Part 70 OP in Section III-D. Notice of intent to test, the applicable test methods, acceptable test method operating conditions, and the requirement for three runs are outlined in this regulation. Air Quality requirements for initial performance testing are identical to 40 CFR 60.8. Air Quality also requires periodic performance testing on emission units based upon throughput or usage. More discussion is in this document under the compliance section.

40 CFR 60.11-Compliance with standards and maintenance requirements.

Discussion: Subpart GG also requires fuel monitoring and sampling to meet a standard. Subpart GG requirements are addressed in the Part 70 permit. AQR Section 26 is more stringent than the federal opacity standards, setting a maximum average of 20 percent opacity for a period of more than 6 consecutive minutes. Chuck Lenzie Generating Station shall operate in a manner consistent with this section of the regulation.

40 CFR 60.12- Circumvention

Discussion: This prohibition is Condition I-A-27 in the Part 70 OP. This is also local rule AQR 80.1.

40 CFR 60.13-Monitoring requirements.

Discussion: This section requires that CEMS meet Appendix B and Appendix F standards of operation, testing and performance criteria. Sections III-C of the Part 70 OP contains the CEMS conditions and citations to Appendix B and F. In addition, the QA plan approved for the CEMS follows the requirements outlined including span time and recording time.

Subpart GG- Standards of Performance for Stationary Gas Turbines

40 CFR 60.330-Applicability and designation of affected facility.

Discussion: Subpart GG applies to the four turbines at this source.

40 CFR 60.332-Standard for nitrogen oxides. (NO_X limits using the F formula)

Discussion: See Table C in Section V below.

40 CFR 60.333-Standard for sulfur dioxide.

Discussion: See Table C in Section V below.

40 CFR 60.334-Monitoring of operations.

Discussion: The sole use of pipeline-quality natural gas satisfies this requirement.

40 CFR 60.335-Test methods and procedures.

Discussion: These requirements are found in the conditions for performance testing found in Section III-D of the Part 70 OP.

Subpart Da- Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

40 CFR 60.40a - Applicability

Discussion: The duct burners (EUs: A02, A04, A06 and A08) are subject to the provisions of this subpart. They each have a permit limit of 2,298 MMBtu per hour.

40 CFR 60.42 – Standard for Particulate Matter

Discussion: See Table C in Section V below.

40 CFR 60.43 – Standard for Sulfur Dioxide

Discussion: See Table C in Section V below.

40 CFR 60.44 – Standard for Nitrogen Oxides

Discussion: See Table C in Section V below.

40 CFR 60.46a – Compliance Provisions

Discussion: Section III-B-2 of the Part 70 permit outlines start-up/shut-down events. The ton-per-year limits for the turbines/duct burners include start-up/shut-down emissions. Chuck Lenzie Generating Station has completed all compliance demonstrations and has demonstrated compliance with all applicable emission standards for NO_X and SO_2. The facility employs the use of CEMS on each of the turbine stacks to monitor NO_X emissions. The measurements to be taken are outlined in Section III-C of the Part 70 operating permit.

40 CFR 60.47a – Emission Monitoring

Discussion: The duct burners combust only natural gas; therefore, COMS are not required. The duct burners combust only natural gas; therefore, SO_2 CEMS are not required. The facility is subject to the requirements of 40 CFR 75; therefore, the data acquired by the NO_X CEMS are allowed to be used to show compliance with both 40 CFR 60 Subpart Da and 40 CFR 75. The reporting requirements are outlined in Section III-F of the Part 70 operating permit. The facility has installed a diluent oxygen CEMS. Monitoring requirements are outlined in Section III-C of the Part 70 operating permit. The duct burners exhaust through the same stack as the combustion turbines; therefore, the monitors required for monitoring turbine emissions will also monitor duct burner emissions.

40 CFR 60.48a – Compliance Determination Procedures and Methods

Discussion: The compliance demonstration for this facility is discussed in Section II-D of the Part 70 operating permit.

40 CFR 60.49a – Reporting Requirements

Discussion: These are discussed in Sections II-C and III-F of the Part 70 operating permit.

Subpart Dc- Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR 60.40c – Applicability and Delegation of Authority

Discussion: The auxiliary boilers (EUs: A09 and A10) are each rated at 44.1 MMBtu per hour and therefore, Subpart Dc is applicable to these emission units.

40 CFR 60.42c – Standard for Sulfur Dioxide

Discussion: This section does not pertain to boilers that exclusively fire natural gas.

40 CFR 60.43c – Standard for Particulate Matter

Discussion: This section does not pertain to boilers that exclusively fire natural gas.

40 CFR 60.48c – Reporting and Recordkeeping Requirements

Discussion: These are addressed in Sections II-C, III-E, and III-F in the Part 70 operating permit.

Subpart KKKK–STANDARDS OF PERFORMANCE FOR STATIONARY COMBUSTION TURBINES

40 CFR 60.4305 – Applicability

Discussion: The four turbines (EUs: A01, A03, A05 and A07) are not subject to the provisions of this subpart because these turbines commenced construction, modification, or reconstruction before February 18, 2005.

The auxiliary boilers (EUs: A09 and A10) are subject to 40 CFR 60, Subpart Dc, and the duct burners (EUs: A02, A04, A06 and A08) are subject 40 CFR 60, Subpart Da, and therefore our exempt from Subpart KKKK, per 60.4305(b).

40 CFR 63-NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES:

Subpart ZZZZ—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

40 CFR 63.6585 – Applicablility

Discussion: The three diesel engines (EUs: A12, A13 and A14) are subject to the requirements of this subpart because they are existing engines operating at an area source of HAP. There are no emission standards for these engines so long as the definition of an emergency engine is met. Management practices still apply.

40 CFR PART 64-COMPLIANCE ASSURANCE MONITORING

40 CFR 64.2 – Applicability

Discussion: The CAM Rule is not applicable to the auxiliary boilers (EUs: A09 and A10), the emergency generators (EUs: A12 and A13), the diesel fire pumps (EU: A14), the fuel gas preheater (EU: A16) or cooling tower (EU: A19-A24) based on the applicability statement outlined in 40 CFR 64.2(a)(2), i.e., no control devices are used on these units to achieve compliance with any emission limitation or standard for a regulated air pollutant. The gas turbines are exempt from the CAM Rule for NO_X and CO based on the exemption outlined in 40 CFR 64.2(b)(1)(vi). The permit specifies a continuous compliance determination method for the

NO_X and CO limitations in the form of a CEMS, required for Part 60 and Part 75 compliance. These units are also exempt from the CAM Rule for NO_X based on the exemption outlined in 40 CFR 64.2(b)(1)(iii) for Acid Rain Program Requirements. The CAM Rule is not applicable to these units for SO_2 based on the applicability statement outlined in 40 CFR 64.2(a)(2). Further, SO_2 would be exempt from the CAM Rule based on the exemption outlined in 40 CFR 64.2(b)(1)(iii) for Acid Rain Requirements. The CAM Rule is not applicable to these units for PM_{10}, HAPs or NH_3 based on the applicability statement outlined 40 CFR 64.2(a)(2). Combustion turbines/duct heaters (EUs: A01-A08) are also not CAM-applicable for VOC emissions based on the exemption outlined in 40 CFR 64.2(a)(3), i.e., the potential precontrol emissions are less than the major source threshold.

40 CFR PART 72-ACID RAIN PERMITS REGULATION

Subpart A – Acid Rain Program General Provisions

40 CFR 72.6 – Applicability

Discussion: Chuck Lenzie Generating Station is defined as a utility unit in the definitions for Part 72; therefore, the provisions of this regulation apply.

40 CFR 72.9 – Standard Requirements

Discussion: Chuck Lenzie Generating Station has applied for all of the proper permits under this regulation.

Subpart B – Designated Representative

Discussion: Chuck Lenzie Generating Station has a Certificate of Representation for Designated Representative on file. They have fulfilled all requirements under this subpart.

Subpart C – Acid Rain Permit Applications

Discussion: Chuck Lenzie Generating Station has applied for an acid rain permit.

Subpart D – Acid Rain Compliance Plan and Compliance Options

Discussion: This subpart discusses the individual requirements necessary for a complete compliance plan. A compliance plan exists for each combustion turbine.

Subpart E – Acid Rain Permit Contents

Discussion: Chuck Lenzie Generating Station has applied for an acid rain permit, and it will contain all information to demonstrate compliance with this subpart.

40 CFR 73 – ACID RAIN SULFUR DIOXIDE ALLOWANCE SYSTEM

Discussion: Chuck Lenzie Generating Station is an affected source pursuant to 40 CFR 72.6 of this chapter because it fits the definition of a utility unit; therefore, this regulation shall apply.

Subpart B – Allowance Allocations

Discussion: Chuck Lenzie Generating Station is not listed on either the Phase I or Phase II tables because it is a newer power plant; therefore, it will not have an initial allocation per 40 CFR 73.10.

Subpart C – Allowance Tracking System

Discussion: Chuck Lenzie Generating Station is considered a new unit. A complete certificate of representation has been received and an account has been established for this facility. Chuck Lenzie Generating Station shall follow all guidelines and instructions presented in this subpart while maintaining its allowance account.

Subpart D – Allowance Transfers

Discussion: When an allowance transfer is necessary, Chuck Lenzie Generating Station shall follow all procedures in this subpart.

Subpart E – Auctions, Direct Sales, and Independent Power Producers Written Guarantee

Discussion: This subpart outlines the auction process for allowance credits.

Subpart F – Energy Conservation and Renewable Energy Reserve

Discussion: There are no qualified conservation measures or renewable energy generation processes at this facility; therefore, this subpart does not apply.

40 CFR 75-CONTINUOUS EMISSION MONITORING

Discussion: Chuck Lenzie Generating Station is subject to the Acid Rain emission limitations of 40 CFR 72; therefore, the source is subject to the monitoring requirements of this regulation.

Each combined cycle turbine unit has been equipped with both a NO_X CEMS and diluent (oxygen/carbon dioxide) monitors. Each turbine unit is also equipped with a fuel flow monitor. The data from the CEMS are used to provide quarterly acid rain reports to both EPA and Air Quality.

All required monitoring plans, RATA testing protocols, and certification testing reports have been provided to EPA and Air Quality. Initial CEMS certification testing was completed on March 28, 2006. The CEMS Quality Assurance Plan was submitted to Air Quality on August 26, 2005 and approved on April 24, 2006.

V. COMPLIANCE

A. Compliance Certification

Requirements for compliance certification:

(a) The schedule for the submittal of reports to the Air Quality shall be as follows:

Required Report	Applicable Period	Due Date[1]
Semiannual Report for 1st Six-Month Period	January, February, March, April, May, June	July 30 each year
Semiannual Report for 2nd Six-Month Period, Any additional annual records required.	July, August, September, October, November, December	January 30 each year
Annual Compliance Certification Report	Calendar Year	January 30 each year
Annual Emission Inventory Report	Calendar Year	March 31 each year
Notification of Malfunctions, Startup, Shutdowns or Deviations with Excess Emission	As Required	Within 24 hours of the Permittee learns of the event

Required Report	Applicable Period	Due Date[1]
Report of Malfunctions, Startup, Shutdowns or Deviations with Excess Emission	As Required	Within 72 hours of the notification
Deviation Report without Excess Emissions	As Required	Along with semiannual reports
Performance Testing	As Required	Within 60 days from the end of the test.

[1] If the due date falls on a Saturday, Sunday or a Federal or Nevada holiday, then the submittal is due on the next regularly scheduled business day

B. Compliance Summary

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 0	Definitions	Applicable –The Station will comply with all applicable definitions as they apply.	The Station will meet all applicable test methods should new definitions apply.	The Station complies with applicable requirements.
AQR Section 4	Control Officer	Applicable – The Control Officer or his representative may enter into the Station property, with or without prior notice, at any reasonable time for purpose of establishing compliance.	Nevada Power Company will allow Control Officer to enter the Station property as required.	The Station complies with applicable requirements.
12.5	Part 70 Operating Permit Requirements	Applicable – The Station is a major stationary source under Part 70. Renewal applications are due between 6 and 18 months prior to expiration. Revision applications will be submitted within 12 months of commencing operation of the new or modified emission unit.	The Station submitted the initial Part 70 application within 12 months of notification. Renewal applications have been submitted in a timely manner.	The Station complies with applicable requirements.
AQR Section 14.1.1 Subpart A	New Source Performance Standards (NSPS) General Provisions	Applicable – The Station is an affected facility under the regulations.	Applicable monitoring, recordkeeping and reporting requirements.	The Station complies with applicable requirements.
AQR Section 14.1.(b)(3) Subpart Da	New Source Performance Standards – Standards of Performance for Electric Utility Steam Generating Units	Applicable – The duct burners are natural gas-fired units with heat input greater than 250 MMBtu/hr.	Duct burners meet applicable NO_X emission standards. NO_X emissions determined by EPA Method 7E.	The Station complies with applicable requirements.
AQR Section 14.1.(b)(5)	New Source Performance Standards for Small Industrial – Commercial – Institutional Steam Generating Units	Applicable – The auxiliary boilers are rated between 10 and 100 MMBtu/hr	Record Keeping	The Station complies with applicable requirements.
AQR Section 14.1.40 Subpart GG	Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines	Applicable – The four (4) turbines at the Station are natural gas-fired units with heat input greater than 10 MMBtu/hr.	The four (4) turbines at the Station meet the applicable NO_X emission standard. NO_X emissions determined by EPA Method 7E.	The Station complies with applicable requirements.
AQR Section 18	Permit and Technical Service Fees	Applicable – The Station will be required to pay all required/applicable permit and technical service fees.	The Station is required to pay all required/applicable permit and technical service fees.	The Station complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 21	Acid Rain Permits	Applicable – The Station is an affected facility. The combustion turbines and duct burners are applicable units under the Acid Rain Program.	The Station submitted required acid rain permit forms/applications.	The Station complies with applicable requirements.
AQR Section 22	Acid Rain Continuous Emission Monitoring	Applicable – The Station is an affected facility and is required to meet the requirements for the monitoring, recordkeeping, and reporting of flow rate, SO_2, NO_X, and CO_2 emissions.	The Station submitted all required protocols/test plans per ATC permit prior to CEMS certification. CEMS certification was approved by Air Quality.	The Station complies with applicable requirements.
AQR Section 25	Upset/Breakdown, Malfunctions	Applicable – Any upset, breakdown, emergency condition, or malfunction which causes emissions of regulated air pollutants in excess of any permit limits shall be reported to Control Officer. Section 25.1 is locally and federally enforceable.	Any upset, breakdown, emergency condition, or malfunction in which emissions exceed any permit limit shall be reported to the Control Officer within 24 hours of the time the owner or operator first learn of the excess emissions.	In the past, the Station has deviated from this requirement on three (3) isolated occasions due to extenuating circumstances. The Station currently complies with applicable requirements.
AQR Section 26	Emissions of Visible Air Contaminants	Applicable – Opacity for the Station combustion turbines must not exceed an average of 20 percent for a period of more than 6 consecutive minutes.	Compliance determined by EPA Method 9	The Station complies with applicable requirements.
AQR Section 27	Particulate Matter from Process Weight Rate	Applicable – The Station emission units are required to meet the maximum weight based on maximum design rate of equipment.	Compliance determined by meeting maximum particulate matter discharge rate based on process rate from AQR Table 27-1.	The Station complies with applicable requirements.
AQR Section 28	Fuel Burning Equipment	Applicable – The PM emission rate for the combustion turbines and duct burners are well below those established based on Section 28 requirements.	Maximum allowable PM emission rate determined from equation in Section 28.	The Station complies with applicable requirements.
AQR Section 40	Prohibition of Nuisance Conditions	Applicable – No person shall cause, suffer or allow the discharge from any source whatsoever such quantities of air contaminants or other material which cause a nuisance. Section 40 is locally enforceable only.	The Station air contaminant emissions controlled by pollution control devices or good combustion in order not to cause a nuisance.	The Station complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
AQR Section 41	Fugitive Dust	Applicable – The Station shall take necessary actions to abate fugitive dust from becoming airborne.	The Station utilizes appropriate best practices to not allow airborne fugitive dust.	The Station complies with applicable requirements.
AQR Section 42	Open Burning	Applicable – In event the Station burns combustible material in any open areas, such burning activity will have been approved by Control Officer in advance. Section 42 is a locally enforceable rule only.	The Station will contact the Air Quality and obtain approval in advance for applicable burning activities as identified in the rule.	The Station complies with applicable requirements.
AQR Section 43	Odors in the Ambient Air	Applicable – An odor occurrence is a violation if the Control Officer is able to detect the odor twice within a period of an hour, if the odor causes a nuisance, and if the detection of odors is separated by at least fifteen minutes. Section 43 is a locally enforceable rule only.	The Station will not operate its facility in a manner which will cause odors.	The Station complies with applicable requirements.
AQR Section 70.4	Emergency Procedures	Applicable – The Station submitted an emergency standby plan for reducing or eliminating air pollutant emissions in the Section 16 Operating Permit Application.	The Station submitted an emergency standby plan and received the Section 16 Operating Permit.	The Station complies with applicable requirements.
40 CFR 52.21	Prevention of Significant Deterioration (including Preconstruction permits)	Applicable – The Station PTE > 100 TPY and is listed as one of the 28 source categories.	BACT analysis, air quality analysis using ISCST3, and visibility and additional impact analysis performed for original ATC permits.	The Station complies with applicable sections as required by PSD regulations.
40 CFR 52.1470	SIP Rules	Applicable – The Station is classified as a Title V source, and SIP rules apply.	Applicable monitoring and record keeping of emissions data.	The Station is in compliance with applicable state SIP requirements including monitoring and record keeping of emissions data.
40 CFR 60, Subpart A	Standards of Performance for New Stationary Sources (NSPS) – General Provisions	Applicable – The Station is an affected facility under the regulations.	Applicable monitoring, recordkeeping and reporting requirements.	The Station complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR 60, Subpart Da	Standards of Performance for New Stationary Sources (NSPS) – Electric utility steam generating units with heat input greater than 250 MMBtu/hr.	Applicable – The duct burners are natural gas-fired units with heat input greater than 250 MMBtu/hr.	Duct burners meet applicable NO_X and PM emission standards. NO_X emission determined by EPA Method 7E and PM_{10} by EPA Method 201/201a and 202.	The Station complies with applicable requirements.
40 CFR 60, Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Stem Generating Units	Applicable – The Auxiliary boilers are over 10 MMBtu/hr and not subject to 40 CFR Subpart KKKK	No testing required by 40 CFR 60, Subpart Dc when burning natural gas.	The Station Complies with applicable Requirements
40 CFR 60, Subpart GG	Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines	Applicable – The four (4) CTGs at the Station are natural gas-fired units with heat input greater than 10 MMBtu/hr.	The four CTGs meet the applicable NO_X emission standard. NO_X emission determined by EPA Method 7E.	The Station complies with applicable requirements.
40 CFR 60	Appendix A, Method 9 or equivalent, (Opacity)	Applicable – Emissions from stacks are subject to opacity standards.	Opacity determined by EPA Method 9.	The Station complies with applicable requirements.
40 CFR 60	Appendix A, Method 20 or equivalent	Applicable – The CTG emissions at the Station are subject to requirements for determination of NO_X, SO_2, and diluent emissions from CTGs.	Emissions determined from EPA Method 20 or Equivalent.	The Station complies with applicable requirements.
40 CFR 63, Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	Applicable – The diesel emergency engines are existing emergency engines as defined.	Not applicable	The Station complies with applicable requirements.
40 CFR 63, Subpart JJJJJJ	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources	Not Applicable – The units are natural gas fueled.	Not Applicable	Not Applicable
40 CFR 64	Compliance Assurance Monitoring	Not Applicable – See the regulatory review for 40 CFR 64—Compliance Assurance Monitoring under Section IV-B of this document.	The Station does not have CAM requirements, but does have compliance demonstration requirements for regulated pollutants.	The Station complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR 68	Chemical Accident Prevention Provisions	Not Applicable – The Station stores or handles 19% aqueous ammonia (NH_3) which is less than the applicable threshold.	Construction approval and a Risk Management Plan (RMP) were not required for the Nevada Department of Environmental Protection for storage and use of NH_3. The Station adheres to Station management programs.	The Station complies with applicable requirements.
40 CFR 72	Acid Rain Permits Regulation	Applicable – The Station is an affected facility. The CTGs and duct burners are applicable units under the Acid Rain Program.	The Station submitted required acid rain permit forms/applications.	The Station complies with applicable requirements.
40 CFR 73	Acid Rain Sulfur Dioxide Allowance System	Applicable – The Station is an affected facility. The permittee will obtain SO_2 allowances based on the calculated actual emissions.	The Station shall be required to obtain required SO_2 allowances.	The Station complies with applicable requirements.
40 CFR 75	Acid Rain CEMS	Applicable – The Station is an affected facility and is required to meet the requirements for the monitoring, recordkeeping and reporting of flow rate, SO_2, NO_X, and CO_2 emissions.	The Station submitted all required protocols/test plans per ATC permit prior to CEMS certification. The Station submitted Initial Certification applications within 45 days of last certification test. Air Quality and EPA approve CEMS certifications.	The Station complies with applicable requirements.

C. Streamlining Demonstration for Permit Shield Purposes

Regulation (40 CFR)	Regulatory Standard	Permit Limit	Value Comparison				Averaging Period Comparison			Streamlining Statement for Shielding Purposes
			Relevant Heat Input or Load Level[1]	Standard Value, in Units of the Permit Limit	Permit Limit Value	Is Permit Limit Equal or More Stringent?	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent?	
60.332 (GG)	75 ppmvd NO_X @ 15% O_2 (2)	3.0 ppmvd NO_X @ 15% O_2	N/A	75 (2)	3.0	Yes	4 hour	3 hour	Yes	The permit limit is more stringent than the standard, based upon both concentration and averaging time. Compliance with the permit demonstrates compliance with the standard.
60.333 (GG)	0.8% sulfur by weight (8000 ppmw)	0.5 gr/ 100 scf	N/A	260 (3)	0.5	Yes	N/A	N/A	Yes	The permit limit is more stringent than the standard. Compliance with the permit demonstrates compliance with the standard.
60.42 (Da)	0.03 lb PM per MMBtu	28.25 lb PM_{10} per hr	Low Heat Input	33	28.25	Yes	30-day rolling	1 hour	Yes	The permit limit is more stringent than the standard, based upon both mass and averaging time. Compliance with the permit demonstrates compliance with the standard.
			High Heat Input	96						

Regulation (40 CFR)	Regulatory Standard	Permit Limit	Value Comparison				Averaging Period Comparison			Streamlining Statement for Shielding Purposes
			Relevant Heat Input or Load Level[1]	Standard Value, in Units of the Permit Limit	Permit Limit Value	Is Permit Limit Equal or More Stringent?	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent?	
60.42 (Da)	20% Opacity	20% Opacity	N/A	20	20	Yes	60-minute period, excepting 6 minutes	60-minute period, excepting 6 minutes	Yes	The permit limit is equal to the standard. Compliance with the permit demonstrates compliance with the standard.
60.43 (Da)	0.20 lb SO_2 per MMBtu	4.78 lb SO_2 per hour	Low Heat Input	220	4.78	Yes	30-day rolling	1 hour	Yes	The permit limit is more stringent than the standard, based upon both mass and averaging time. Compliance with the permit demonstrates compliance with the standard.
			High Heat Input	641						
60.44 (Da)	0.20 lb NO_X per MMBtu	3.0 ppm NO_X @ 15% O_2	N/A	54	3.0	Yes	30-day rolling	3 hour	Yes	The permit limit is more stringent than the standard, based upon both concentration and averaging time. Compliance with the permit demonstrates compliance with the standard.

Regulation (40 CFR)	Regulatory Standard	Permit Limit	Value Comparison				Averaging Period Comparison			Streamlining Statement for Shielding Purposes
			Relevant Heat Input or Load Level[1]	Standard Value, in Units of the Permit Limit	Permit Limit Value	Is Permit Limit Equal or More Stringent?	Standard Averaging Period	Permit Limit Averaging Period	Is Permit Limit Equal or More Stringent?	
60.44 (Da)	1.6 lb NO_X per MW-hr	28.95 lb NO_X per hour	Low Load	256	28.95	Yes	30-day rolling	1 hour	Yes	The permit limit is more stringent than the standard, based upon both mass and averaging time. Compliance with the permit demonstrates compliance with the standard.
			High Load	349						
63. 11195 (JJJJJJ)	-	-	-	-	-	-	-	-	-	Not applicable

[1] Heat input and load levels used were as follows:

Low Heat input indicates the minimum heat input for normal (Mode 6) operation. Mode 6 is described in the ATC/OP, Modification 1, Amendment 2, Condition III-A-3. A conservative value of 1,100 MMBtu/hr was used.

High Heat Input indicates heat input at the permit limit, or 3,205 MMBtu/hr.

Low Load for Subpart Da purposes is the maximum load with no duct firing. A conservatively low value of 160 MW was used.

High Load for Subpart Da purposes is the nominal rated load for the turbine and duct burner combined, or 218 MW as listed in the ATC/OP.

[2] The 60.332 NO_X standard is a formula; the value used here (75 ppmvd) is the minimum possible value of the standard for any emission unit.

Note: Formulas used:

$EF = C_d * C_f * F_d * 20.9 / (20.9 - \%O_2)$

$E = EF * HI$

where:

EF = emission rate (lb/MMBtu);

C_d = emission concentration (ppmvd);

C_f for NO_X = 1.194E-07 (lb NO_X/dscf ppm);

F_d = 8,710 dscf/MMBtu, dry basis F factor for O_2 dilution for natural gas;

$\%O_2$ = 15% (the oxygen volume at the stated limit;

E = mass emission rate (lb/hr); and

HI = heat input (MMBtu/hr).

[3] Sulfur content was converted from percent by weight to gr per 100 scf as follows: 0.8% sulfur = 56 gr sulfur per lb natural gas. AP-42 defines natural gas as generally more than 85 percent methane and varying amounts of ethane propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Assuming an average molecular weight of 18 lb/lb-mol, 1 lb natural gas = 2.14×10^3 scf. Lastly, 56 gr sulfur per 2.14×10^3 scf natural gas = 260 gr/100 scf.

D. Summary of Monitoring for Compliance

Emission Unit	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A01/A02 A03/A04 A05/A06 A07/A08	Combustion turbines/duct burner units	CO, NO_X, SO_2, PM_{10}, VOC, HAPs	AQR Sections 12 40 CFR 60 Subpart GG 40 CFR 60 Subpart Da	Annual and short-term emission limits.	CEMS for NO_X, CO. CEMS for NO_X and CO and initial and all previous testing for VOC and PM_{10}. Compliance for SO_2 and HAPs shall be based on sole use of natural gas as fuel and emission factors. Recording is required for compliance demonstration.
A01/A02 A03/A04 A05/A06 A07/A08	Combustion turbines/duct burner units	Opacity	AQR Section 26	Less than an average of 20 percent opacity for a period of more than 6 consecutive minutes.	Sole use of pipeline quality natural gas as fuel, monitoring of visible emission in accordance with 40 CFR 60.552Da, and EPA Method 9 performance testing as outlined in the Part 70 Operating Permit.
A09, A10	Auxiliary boilers	CO, NO_X, SO_2, PM_{10}, VOC	AQR Sections 12 40 CFR 60 Subpart Dc	Annual and short-term emission limits.	Stack testing for NO_X and CO by EPA Methods as outlined in Part 70 Permit. Compliance for PM_{10}, SO_2, and VOC shall be based on sole use of natural gas as fuel and emission factors. Recording is required for compliance demonstration.
A09, A10	Auxiliary boilers	Opacity	AQR Section 26	Less than an average of 20 percent opacity for a period of more than 6 consecutive minutes.	Sole use of natural gas as fuel and quarterly visual emission checks as outlined in Part 70 OP.
A12, A13	Emergency generator	CO, NO_X, SO_2, PM_{10}, VOC, HAPs	AQR Sections 12 40 CFR 63, Subpart ZZZZ	Restricted testing hours.	Compliance for regulated pollutants shall be based on sole use of low-sulfur diesel fuel and emission factors. Recording is required for compliance demonstration.
A12, A13	Emergency generator	Opacity	AQR Section 26	Less than an average of 20 percent opacity for a period of more than 6 consecutive minutes.	Sole use of low-sulfur diesel fuel and quarterly visual emission checks as outlined in Part 70 OP.
A14	Diesel fire pump	CO, NO_X, SO_2, PM_{10}, VOC, HAPs	AQR Sections 12, 40 CFR 63, Subpart ZZZZ	Restricted testing hours.	Compliance for regulated pollutants shall be based on sole use of low-sulfur diesel fuel and emission factors. Recording is required for compliance demonstration.
A14	Diesel fire pump	Opacity	AQR Section 26	Less than an average of 20 percent opacity for a period of more than 6 consecutive minutes.	Sole use of low-sulfur diesel fuel and quarterly visual emission checks as outline in Part 70 OP.

Emission Unit	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A16	Gas heater	CO, NO_X, SO_2, PM_{10}, VOC	AQR Sections 12	Annual emission limits.	Compliance for PM_{10}, SO_2, and VOC shall be based on sole use of natural gas as fuel and emission factors. Compliance was established by initial and past subsequent performance tests. Recording is required for compliance demonstration.
A16	Gas heater	Opacity	AQR Section 26	Less than an average of 20 percent opacity for a period of more than 6 consecutive minutes.	Sole use of natural gas as fuel and quarterly visual emission checks as outlined in Part 70 OP.

VI. EMISSION REDUCTION CREDITS (OFFSETS)

The source is subject to offset requirements in accordance with Section 12.7 of the Clark County Air Quality Regulations. Offset requirements and associated mitigation are pollutant-specific.

VII. ADMINISTRATIVE REQUIREMENTS

Section 12.5 requires that Air Quality identify the original authority for each term or condition in the Part 70 Operating Permit. Such reference of origin or citation is denoted by [italic text in brackets] after each Part 70 Permit condition.

Air Quality proposes to issue the Part 70 Operating Permit conditions on the following basis:

Legal:

On December 5, 2001 in Federal Register Volume 66, Number 234 FR30097 the EPA fully approved the Title V Operating Permit Program submitted for the purpose of complying with the Title V requirements of the 1990 Clean Air Act Amendments and implementing Part 70 of Title 40 Code of Federal Regulations.

Factual:

Chuck Lenzie Generating Station has supplied all the necessary information for Air Quality to draft Part 70 Operating Permit conditions encompassing all applicable requirements and corresponding compliance.

Conclusion:

Air Quality has determined that Chuck Lenzie Generating Station will continue to determine compliance through the use of CEMS, performance testing, reporting, record keeping, coupled with annual certifications of compliance. Air Quality proceeds with the preliminary decision that a Part 70 Operating Permit should be issued as drafted to Chuck Lenzie Generating Station for a period not to exceed five years.

Attachments

Wet Surface Air Coolers

Requested Allowable:

Wet Surface Air Cooler Emissions

Unit	Description	Drift Loss %[1]	Circulation Rate[1] (gpm)	TDS[2] (mg/l)	Hours of Operation (hr/yr)	PM10 Emissions (lb/hr) per unit[3]	PM10 Emissions (tpy) per unit
#1	Niagara Blower Company Wet Surface Air-cooler	0.001%	5040	7400	5000	0.088	0.22
#2	Niagara Blower Company Wet Surface Air-cooler	0.001%	5040	7400	5000	0.088	0.22

[1] Taken from Duke/Fluor Daniel wet surface air cooler spec sheet approved for construction 1/4/02 item No. 1CC-CLR-0100/2CC-CLR-0100.
[2] TDS value is based on conductivity readings from the units.
[3] Assume 47% of drift evaporates as PM10 per DAQ guidance.

Notes:
TDS conversion: 1 mg/l = 8.34x10-6 lb/gal.
PM_{10} emissions (lb/hr) = TDS concentration x Drift loss factor x circulating water rate x 8.34x10-6 lb/gal x 60 min/hr

Unrestricted hours for wet surface cooling towers:

(0.44 tpy/5,000 hrs) x 8,760 hrs = 0.78 tpy

Cooling Towers

Requested Allowable:

Chiller Cooling Tower Emissions

Unit	Description	Drift Loss[1]	Flow Rate (gpm)[1]	TDS[2] (mg/l)	Hours of Operation (hr/yr)	PM10 Emissions (lb/hr) per unit[3]	PM10 Emissions (tpy) per unit
#1	BAC Series 3000 cross-flow cooling tower	0.001%	9834	7400	8760	0.171	0.75
#2	BAC Series 3000 cross-flow cooling tower	0.001%	9834	7400	8760	0.171	0.75
#3	BAC Series 3000 cross-flow cooling tower	0.001%	9834	7400	8760	0.171	0.75
#4	BAC Series 3000 cross-flow cooling tower	0.001%	9834	7400	8760	0.171	0.75
#5	BAC Series 3000 cross-flow cooling tower	0.001%	9834	7400	8760	0.171	0.75
#6	BAC Series 3000 cross-flow cooling tower	0.001%	9834	7400	8760	0.171	0.75

[1] Taken from Duke/Fluor Daniel Cooling Tower, Turbine Inlet Chilling System Spec Sheet May 7, 2002.

[2] TDS value is based on conductivity readings from the units.

[3] Assume 47% of drift evaporates as PM10 per DAQ guidance.

Notes:

TDS conversion: 1 mg/l = 8.34x10-6 lb/gal.

PM_{10} emissions (lb/hr) = TDS concentration x Drift loss factor x circulating water rate x 8.34x10-6 lb/gal x 60 min/hr

Lime Silo with Filter and Soda Ash Silo with Filter (calculation for insignificance)

Silo	PTE with unlimited throughput (tpy)	PTE with one unloading per week (TPY)	Max historical actual emisions (TPY)	Max historical deliveries (No/year)
Lime	0.97	0.029	0.0013	<10
Soda Ash	0.97	0.029	0.004	<30

Clark County Department of Air Quality and Environmental Management – Air Quality Regulations and SIP status

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
0. Definitions	applicable definitions	yes	entire source
1. Definitions	“Affected Facility”, “Dust”, “Existing Gasoline Station”, “Fumes”, “Mist”, “New Gasoline Stations”, “New Source”, “Single Source”, “Standard Conditions”, “Uncombined Water”.	Yes	entire source

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
4. Control Officer	all subsections 4.7.3 and 4.12.1 through 4.12.3 in SIP	partial	entire source
5. Interference with Control Officer	all subsections	yes	entire source
6. Injunctive Relief	all subsections	yes	entire source
7. Hearing Board and Hearing Officer	all subsections	no	entire source
8. Persons Liable for Penalties - Punishment: Defense	all subsections	yes	entire source
9. Civil Penalties	all subsections	no	entire source
10. Compliance Schedule	when applicable; applicable subsections	yes	entire source
12.0. Applicability, General Requirements and Transition Procedures	all subsections	yes	entire source
13. Emission Standards for Hazardous Pollutants	Delegated Program CCAQR Section 13.2(b)(82): Subpart ZZZZ National Emission Standards for Hazardous Air Pollutant for Stationary Reciprocating Internal Combustion Engines	no	Diesel Engines
14. New Source Performance Standards	Delegated Program CCAQR Section 14.1(b)(3): Subpart Da Standards of Performance for Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978	no	Duct Burners
	CCAQR Section 14.1(b)(5): Subpart Dc Standards of Performance for Small Industrial – Commercial – Institutional Steam Generating Units	no	Auxiliary Boilers
	CCAQR Section 14.1(b)(40): Subpart GG Standards of Performance for Gas Turbines	no	CTG units
18. Permit and Technical Service Fees	all subsections 18.1 through 18.5.2 and 18.6 through 18.12 in SIP	partial	entire source
21. Acid Rain Permits	all subsections	no	entire source
22. Acid Rain Continuous Emission Monitoring	all subsections	no	entire source

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
24. Sampling and Testing - Records and Reports	§ 24.1 Requirements for installation and maintenance of sampling and testing facilities § 24.2 Requirements for emissions record keeping § 24.3 Requirements for the record format § 24.4 Requirements for the retention of records by the emission sources (Note: Repealed from SIP on Oct 17, 2014)	no	entire source
25.1 Upset/Breakdown, Malfunctions (1981)	§ 25.1 Requirements for the excess emissions caused by upset/breakdown and malfunctions	no	entire source
25.2 Upset/Breakdown, Malfunctions (1981)	§ 25.2 Reporting and Consultation	yes	entire source
26. Emission of Visible Air Contaminants (1981)	§ 26.1 Limit on opacity (≤ an average of 20 percent for a period of more than 6 consecutive minutes)	yes	entire source
27. Particulate Matter from Process Weight Rate	all subsections	yes	entire source
28. Fuel Burning Equipment	Emission Limitations for PM	yes	entire source
29. Sulfur Contents of Fuel Oil	Repealed by County	yes	entire source
30. Incinerators	Repealed by County	yes	entire source
40. Prohibitions of Nuisance Conditions	§ 40.1 Prohibitions	no	entire source
41. Fugitive Dust	§ 41.1 Prohibitions	yes	entire source
42. Open Burning	§ 42.2	no	entire source
43. Odors In the Ambient Air	§ 43.1 Prohibitions coded as Section 29	no	entire source
52. Gasoline Dispensing Facilities	Repealed by County	yes	entire source
60. Evaporation and Leakage	all subsections Repealed by County and from SIP in 2011	no	entire source
70. Emergency Procedures	all subsections	yes	entire source
80. Circumvention	all subsections	yes	entire source