DES
DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY
air quality desert conservation PROGRAM sustainability

4701 W. Russell Rd Suite 200
Las Vegas, NV 89118-2231
Phone (702) 455-5942
Fax (702) 383-9994

PART 70
TECHNICAL SUPPORT DOCUMENT
(STATEMENT of BASIS)

APPLICATION FOR:
Part 70 Operating Permit Significant Revision

SUBMITTED BY:
Nevada Power Company, dba NV Energy

FOR:
Harry Allen Generating Station

Source ID: 00533

SIC code 4911, "Electric Services"
NAICS code 221112, "Fossil Fuel Electric Power Generation"

TSD Date: February 23, 2023

EXECUTIVE SUMMARY

Harry Allen Generating Station (HAS) is an electrical power generating station located at Apex Dry Lake Industrial Park on 14601 North Las Vegas Boulevard, Las Vegas, Nevada. The legal description of the source location is: portions of T17S, R63E, Sections 23, 25, and 36 in Apex Valley, County of Clark, State of Nevada. HAS is situated in Hydrographic Area 216 (Garnet Valley). Garnet Valley is designated as attainment for all pollutants.

HAS is classified as a Categorical Stationary Source, as defined by AQR 12.2.2(j)(1). HAS is a major stationary source for PM_{10}, $PM_{2.5}$, NO_x, and CO, and is minor for SO_2, VOC, and HAP. HAS is a source of Greenhouse Gasses (GHG). HAS operates a total of four combustion turbines of which two are simple cycle turbines and the other two are combined cycle turbines. Other operating emission units include three emergency generators and one diesel emergency fire pump, and the following activities designated as insignificant activities: a wet surface air cooler, mobile combustion sources, station maintenance activities, maintenance shop activities, steam cleaning operations, emergency genset, fire pump diesel tanks, ammonia storage vessels, and lubrication oil sumps and vents.

A Part 70 Operating Permit (Part 70 OP) renewal was issued on October 29, 2020 and a reopening for cause was issued on December 1, 2021. HAS submitted applications for significant revisions on January 12, 2022 and July 6, 2022.

The following table summarizes the source's potential to emit (PTE) of each regulated air pollutant from all emission units addressed by this Part 70 Operating Permit.

Table 1. Source-wide PTE

	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP	GHG[1]
PTE	151.40	151.40	311.73	279.99	14.72	64.93	5.65	2,430,928
Major Stationary Source Thresholds (Categorical)	100	100	100	100's	100	100	10/25	---

[1] GHG is expressed as CO_2e.

The Clark County Department of Environment and Sustainability, Division of Air Quality (DAQ) has been delegated authority to implement the requirements of the Part 70 Operating Permit Program.

Based on the information submitted by the applicant and a technical review performed by DAQ staff, DAQ proposes significant revisions to the Part 70 Operating Permit for HAS.

The turbines are currently subject to the requirements of 40 CFR Part 60, Subpart GG and associated duct burners are subject to 40 CFR Part 60, Subpart Db. The fire pump is subject to the requirements of 40 CFR Part 60, Subpart IIII. The emergency generators are subject to the requirements of 40 CFR Part 63, Subpart ZZZZ. The facility is also subject to 40 CFR Part 72, and 75. After the upgrade of the turbines, the turbines and associated burners will be subject to 40 CFR Part 60, Subpart KKKK, instead of Subparts GG and Db.

TABLE OF CONTENTS

LIST OF TABLES

I. ACRONYMS

Table I-1: Acronyms and Abbreviations

Acronym	Term
AQR	Clark County Air Quality Regulation
ATC	Authority to Construct
BACT	Best Achievable Control Technology
CAAA	Clean Air Act Amendments
CEMS	Continuous Emissions Monitoring System
CFC	chlorofluorocarbon
CFR	Code of Federal Regulations
CO	carbon monoxide
CTG	combustion turbine-generator
CTUP	combustion turbine upgrade turbine
DAQ	Division of Air Quality
DES	Clark County Department of Environment and Sustainability
DLN	dry-low NOx
EPA	U.S. Environmental Protection Agency
EU	emission unit
GHG	greenhouse gases
gpm	gallons per minute
HAP	hazardous air pollutant
HAS	Harry Allen Station
HCFC	hydrochlorofluorocarbon
HHV	Higher Heating Value
Hp	horsepower
HRSG	Heat Recovery Steam Generator
kW	kilowatt
LHV	Lower Heating Value
MEQ	megawatt equivalent
MMBtu	Millions of British thermal units
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
RICE	reciprocating internal combustion engine

Acronym	**Term**
RMP	Risk Management Plan
SCC	Source Classification Codes
scf	standard cubic feet
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur oxides
TDS	total dissolved solids
ULN	ultra-low NOx
VOC	volatile organic compound

II. SOURCE INFORMATION

A. General

Responsible Official:	Jason Hammons
Telephone Number:	(702) 402-5762
FAX Number:	(702) 402-2051
Source Contact:	Marc Dunn
Telephone Number:	(702) 402-8254

B. Description of Process

HAS is a natural gas fired electric utility generating facility consisting of four Combustion Turbine Generator (CTG) units (Turbine Units 3, 4, 5 & 6). All generating and support processes at the site are grouped under SIC 4911, "Electric Services," and NAICS 221112, "Fossil Fuel Electric Power Generation." The source consists of natural gas CTG units, diesel emergency generators, a one-diesel emergency fire pump, and the following activities designated as insignificant: a wet surface air cooler, mobile combustion sources, station maintenance activities, maintenance shop activities, steam cleaning operations, an emergency genset, fire pump diesel tanks, ammonia storage vessels, and lubrication oil sumps and vents.

C. Permitting Actions

Significant Revision – January 12, 2022

This significant revision incorporates the 12.4 ATC issued on 11/14/2022 for the upgrade to the two GE 7FA natural gas-fired combustion turbines, Units 5 and 6 (EUs: A01 and A02). The ATC revised the existing annual heat input for these turbines by replacing the hourly heat input of 1,540 MMBtu (LHV). The upgraded turbines and associated duct burners will be subject to 40 CFR Part 60, Subpart KKKK with this revision.

Because the ATC was not subject to AQR 12.2.16.6 – Enhanced public participation procedures, per the AQR regulations, incorporation of an ATC triggers a significant revision to the Part 70 OP.

The TSD for the ATC issued on 11/14/2022 describes in detail the turbine upgrade project, associated NSR and applicable requirements.

Significant Revision – July 6, 2022

This significant revision application requested the removal of the daily operating restriction of 20 hours/day that was associated with the 6,135 hour annual limit for Turbine Unit 3 (EU: 53301). The justification for removing this limit is detailed in Section III-D of this TSD. Removing the daily limit increases the short-term emissions, but the PTE is calculated on the annual limit. The major NSR analysis for this request indicated the project is a minor modification. After review of the file and the application, this daily limit has no impact on the source operations and was not part of the original BACT; therefore, it can be removed. It is noted that if this annual limit (6,135 hours/year) is to be revised, the source may be subject to a new BACT analysis.

Other

The following has also been incorporated into this permitting action:

- the annual hours of operation limits are based on any 12-month consecutive period; and
- the emergency generators' operational restrictions have been updated with the new federal language for demand response.

D. Operating Scenario

CTG: The current maximum permitted heat input rate for Turbine Units 5 and 6 (EUs: A01 and A02) while firing natural gas is 1,540 MMBtu/hr each, and the associated duct burners (EUs: A03 and A04) are permitted at 173 MMBtu/hr each. These heat input rates are based on LHV. The upgraded CT's estimated hourly heat input rate of 1,684 MMBtu/hr (LHV) at 67 °F multiplied by 8,760 hours results in 14,751,840 MMBtu/year (LHV). The hourly duct burner heat input limit is to be replaced with an annual limit of 692,000 MMBtu/year (LHV). The calculation for this limit is based on the duct burner manufacturer's hourly heat input of 173 MMBtu/hr multiplied by the annual operating limit of 4,000 hours. The permit will reflect annual heat input limits for these turbines and duct burners.

Turbine Units 3 and 4: The maximum permitted heat input rate for Turbine Unit 3 (EU: 53301) while firing natural gas is 873.1 MMBtu/hr based on LHV. Turbine Unit 4 (EU: A09) is permitted at 1,060 MMBtu/hr based on HHV.

Emergency Fire Pump: The emergency fire pump is permitted to operate up to 100 hours per year for testing and maintenance purposes. This is the 40 CFR Part 60, Subpart IIII limit based on the definition of an emergency engine. The PTE is based on 500 total operating hours per EPA guidance and is not an operational limit when emergencies occur.

Emergency Generators: The emergency generators are permitted to operate up to 100 hours per year for testing and maintenance purposes. This is the 40 CFR Part 63, Subpart ZZZZ limit based on the definition of an emergency engine. The PTE is based on 500 total operating hours and is not an operational limit when emergencies occur.

III. EMISSIONS INFORMATION

A. Total Source Potential to Emit

The source's PTE for pollutants is reflected in Table III-A-1.

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

PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
151.40	151.40	311.73	279.99	14.72	64.93	5.65

The source's PTE of GHG is reflected in Table III-A-2.

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

CO_2	CH_4	N_2O	CO_2e
2,428,458	45.1	4.4	2,430,928

B. Emission Units and PTE

Table III-B-1: List of Emission Units

EU	Description	Rating	Manufacturer	Model Number	Serial Number	SCC
A01	CTG Natural Gas Turbine (Unit 5)	Nominal rating:185 MW or 206 MW upon completion of CTUP (185 MEQ/206 MEQ)	General Electric	PG7241FA	298914	20100201
A02	CTG Natural Gas Turbine (Unit 6)	Nominal rating:185 MW or 206 MW upon completion of CTUP (185 MEQ/206 MEQ)	General Electric	PG7241FA	298915	20100201
A03	Duct Burner HRSG associated with A01	173 MMBtu/hr (LHV) 22.8 MEQ				10100601
A04	Duct Burner HRSG associated with A02	173 MMBtu/hr (LHV) 22.8 MEQ				10100601
A07[1]	Diesel Emergency Engine	400 hp	Perkins	N37881	1	20200102
	Emergency Generator	275 kW	Katolight	D275FJP4	AD129178SLM	
A08[2]	Diesel Emergency Engine	519 hp	Caterpillar	3406	4ZR08055	20200102
	Emergency Generator	350 kW		SR4B	8ER03545	
A09	Natural Gas Only Turbine (Unit 4)	75 MW (MEQ =28)	General Electric	MS7001EA (PG7121)	298532	20100201
53301	Natural Gas Only Turbine (Unit 3)	79.2 MW (MEQ =53)	General Electric	MS7001EA	296449	20100201
53302	Diesel Emergency Engine	900 hp	Cummins	VTA-28-G5	25195586	20200102
	Emergency Generator	500 kW		500DFGA	C940536630	
A11	Diesel Emergency Engine	175 hp	Clarke/John Deere	6068 series	PE6068T751998	20200102
	Fire Pump		Clarke	JU6H-UF34	11-061158-01-01/ QKN282	

[1] Located at the Harry Allen substation.
[2] Located at the Harry Allen switchyard.

The source also operates the following insignificant units and activities that are not included in the Part 70 Operating Permit:

- Mobile Combustion Sources
- Station Maintenance Activities
- Maintenance Shop Activities
- Steam Cleaning Operations
- Emergency Genset and Fire Pump Diesel Tanks
- Ammonia Storage Vessels
- Lubrication Oil Sumps and Vents
- Wet Surface Air Cooler: 2,800 gpm; TDS: 1,500 ppm, 0.0005% drift loss

Table III-B-2: Emission Unit PTE, Including Startup, Shutdown, and Testing/Tuning (tons per year)

EU	$PM_{2.5}/PM_{10}$	NO_x	CO	SO_2	VOC
A01/A03 (Turbine Unit 5)	50.20	85.90	44.68	4.40	28.10
A02/A04 (Turbine Unit 6)	50.20	85.90	44.68	4.40	28.10
A07 Diesel Emer. Generator	0.23	3.13	0.67	0.20	0.27
A08 Diesel Emer. Generator	0.70	2.31	2.41	0.40	0.03
A09 (Turbine Unit 4)	19.21	39.06	33.94	1.22	3.47
53301 (Turbine Unit 3)	30.60	88.60	152.50	4.01	4.60
53302 Diesel Emer. Generator	0.23	6.43	1.00	0.07	0.33
A11 Diesel Emer. Fire Pump	0.03	0.40	0.11	0.02	0.03
Total	**151.40**	**311.73**	**279.99**	**14.72**	**64.93**

Table III-B-3: Startup and Shutdown Emissions for Turbine Unit 4[1] (pounds per hour)

EU: A09	NO_x	CO
Startup	51.05	85.04
Shutdown	23.98	66.38
Combined startup/shutdown	55.53	142.52

[1]Actual emissions shall be included in the annual mass emission reporting. Estimated tonnages of startup emissions are included in the operational PTE in Table III-B-2.

Table III-B-4: Applicable Subpart GG Standards, 4-hour Rolling Average

EU	NO_x STD in ppmvd @ 15% O_2
A01/A03 (Turbine Unit 5)[1]	111
A02/A04 (Turbine Unit 6)[1]	111
A09 (Turbine Unit 4)	95
53301 (Turbine Unit 3)	96

[1]While the subpart GG standard is only applicable to combustion turbines, it is applied here to emissions from both the combustion turbine and the duct burner

Table III-B-5: Turbine Units 3, 4, 5, and 6 Emission Rates, Excluding Startup, Shutdowns, and Testing/Tuning (pounds per hour)

EU	$PM_{2.5}/PM_{10}$	NOx	CO	VOC
A01/A03 (Turbine Unit 5)	11.5	15.4	9.5	6.4
A02/A04 (Turbine Unit 6)	11.5	15.4	9.5	6.4
53301 (Turbine Unit 3)	10.00	28.80	49.70	1.50
A09 (Turbine Unit 4)	9.98	19.50	8.90	1.80

Table III-B-6a: Emission Concentration Limitations, Excluding Startup, Shutdown, and Testing/Tuning Emissions for Turbine Units 5 and 6 (EUs: A01/A03 and A02/A04)[1]

Mode	NOx @ 15% O_2	CO @ 15% O_2	VOC @ 15% O_2
With Duct Firing	2.0 ppmvd	2.0 ppmvd	2.9 ppmvd
Without Duct Firing	2.0 ppmvd	2.0 ppmvd	2.2 ppmvd

[1] Limits based on a 3-hour averaging period.

Table III-B-6b: Emissions Concentration Limitations, Excluding Startup, Shutdown, and Testing/Tuning Emissions for Turbine Units 3 and 4

EU	NO_X @ 15% O_2
53301 (Turbine Unit 3)[1]	9.0 ppmvd
A09 (Turbine Unit 4)[2]	5.0 ppmvd

Limits based on a 3-hour averaging period.
Limits based on a 1-hour averaging period.

Table III-B-7: Emission Rate Limitations for CO during Testing/Tuning (pounds per hour)

EU	CO
A01/A03 (Turbine Unit 5)	400
A02/A04 (Turbine Unit 6)	400
A09 (Turbine Unit 4)	100
53301 (Turbine Unit 3)	200

C. Control Technology

Table III-C-1 lists BACT determinations for the source.

Table III-C-1: BACT Determinations for NVE—Harry Allen Station

EU	Description	BACT Technology	BACT Limits
A01/A03 A02/A04	Unit 5 and 6 - Two Combined Cycle Combustion Turbines, Two 173 MMBtu/hr Duct Burners	Dry Low-NOx Burners, SCR, oxidation catalyst, natural gas combustion, inlet air filters	NO_X: 2.0 ppmvd at 15% O_2 CO: 2.0 ppmvd at 15% O_2
A11	175 hp Diesel Emergency Fire Pump	Turbocharging and aftercooling	Same as 40 CFR Subpart IIII
A07	400 hp Diesel Emergency Generator	Use of 0.0015% sulfur diesel fuel	No limit imposed
A08	519 hp Diesel Emergency Generator	Use of 0.0015% sulfur diesel fuel	No limit imposed

A09	Unit 4, 75 MW natural-gas-fired electric turbine generator	ULN burner, oxidation catalyst, natural gas combustion	5.0 ppmvd NOx on a 1-hour average at 15% O_2
53301	Unit 3, 79.2 MW natural-gas-fired electric turbine generator	DLN burner	9.0 ppmvd NOx on a 3-hour average at 15% O_2
53302	900 hp Diesel Emergency Generator	Use of 0.0015% sulfur diesel fuel	No limit imposed

SCR and DLN were previously identified as BACT for NO_x for EUs A01 and A03. The NO_x concentration of 3 ppm when the initial BACT determination was made has been reduced to 2 ppm by the source due to SCR technology improving during the construction phase of Turbines 5 and 6.

The CO concentrations of 3.5 ppm proposed as initial BACT, and 2.6 ppm when the BACT determination was made, have been reduced to 2 ppm by the source due to catalytic oxidation technology improvement during the construction phase of Turbines 5 and 6.

For PM_{10}, SO_2, and VOC emissions, the use of inlet air filters, pipeline natural gas, and good combustion practices were accepted as BACT for all turbines.

D. Limit Removal Determination for Turbine Unit 3 (EU: 53301)

Actual to Projected Actual Applicability Test

For the purposes of calculating emissions and determining PSD applicability, the source will conduct an evaluation to determine the modification under the definition of "major modification" in AQRs 12.2.2(dd). A project is considered a "major modification for a regulated New Source Review (NSR) pollutant if it causes a significant emissions increase and a significant new emissions increase. The source has applied the actual to projected actual (ATPA) applicability test for this project in accordance with AQR 12.2.1.4(c) and the associated definitions of baseline actual emissions (BAE) and projected actual emissions (PAE) in AQR 12.2.2.

Under the ATPA test, emissions increases of each regulated NSR pollutant are calculated as the sum of the differences between PAE and BAE for the removal of the daily limit. See the Attachments for a breakdown of the values.

Baseline Actual Emissions

In accordance with AQR 12.2.2(c)(2), HAS selected the January 2020 to December 2021 period as the 24-month baseline period for each regulated NSR pollutant in Table III-D-1.

Table III-D-1. Baseline Actual Emissions (tons/year) for Affected Units[1]

Emissions Unit	NO_X	SO_2	CO	PM	PM_{10}	$PM_{2.5}$	VOC
53301	12.65	0.61	11.41	5.36	5.36	5.36	0.80

[1]See Table A-3 in the attachments section for an explanation of table values.

Projected Actual Emissions

In accordance with AQR 12.2.2(nn), HAS estimated the maximum annual rate, in tons per year, at which Turbine Unit 3 is projected to emit in any of the five years following the date this unit resumes regular operation after the project, or in any one of the 10 years following the date of the project if (1) increases in the design capacity or PTE of any regulated NSR pollutant and (2) full utilization of the unit would result in a significant emissions increase or significant net emissions increase at this major source. The PTE of this unit will remain unchanged because the proposed permit revision does not affect the design capacity of the emission unit and the unit will continue to be subject to the current annual operating hours limitation. Therefore, PAE for this unit is for the five year period beginning January 1, 2023 to December 31, 2027.

The maximum annual heat input rates and the regulated NSR pollutants emissions factors noted here are used to calculate the PAE is shown in Table III-D-2.

Table III-D-2. Projected Actual Emissions (tons per year)

Emission Unit	NO_X	SO_2	CO	PM	PM_{10}	$PM_{2.5}$	VOC
53301	100.18	1.78	87.70	30.62	30.62	30.62	4.46

[1]See Table A-6 in the attachment section for an explanation of table values.

Excludable Emissions

In accordance with AQR 12.2.2(nn)(1)(d), a portion of an existing EU's emissions following the change shall be excluded from the emissions increase calculation to the extent that those emissions meet the following criteria:

1. The existing EU could have accommodated these emissions during the baseline period.
2. The emissions are unrelated to the project.

In this case, NV Energy has analyzed the historical operation of this unit and the expected future operating conditions to develop PAE without the project (removal of the daily hours limitation). This will allow the unit to operate 4 additional hours per day for 6,135 operating hours equivalent days per year. Key Parameters used for estimating excludable emissions (EE) are as follows:

Period of operation allowed by the permit	6,135 hours/year
Equivalent number of days (24 hours) periods	256 days per year
Additional operation on a given day	4 hour/day
Duration of operation associated with the removal	1,024 hours/year (4 hours/day * 256 days/year)
Operation period without limit removal	5,111 hours/year

Table III-D-3. Excludable Emissions (tons/year) for Affected EU[1]

Emission Unit	NO_X	SO_2	CO	PM	PM_{10}	$PM_{2.5}$	VOC
53301	70.81	0.88	61.65	20.15	20.15	20.15	2.91

[1]See Table A-8 in the attachment section for an explanation of table values.

Project Emission Increases for Prevention of Significant Deterioration Applicability

The project emissions increases in Table V-4 were calculated in accordance with the applicability procedures in AQR 12.2.1.4(c). The increases in emissions of regulated NSR pollutants from the proposed change are quantified for purposes of determining the applicability to PSD ATC requirements (AQR 12.4.1.1), major modification applicability (AQR 12.2.1.4) under PSD, and compliance with applicable local, state, and federal air quality regulations.

The project emissions increase (PEI) for each regulated NSR pollutant was calculated by subtracting BAE and EE from PAE the project-affected emission unit. Table III-D-4 shows the increases are below the significant emissions rates defined at AQR 12.2.2(uu) for all regulated NSR pollutants.

Table III-D-4. Emissions Increases for PSD Applicability (tons/year) [1]

Emissions Unit	NO_X	SO_2	CO	PM	PM_{10}	$PM_{2.5}$	VOC
53301	16.72	0.29	14.64	5.11	5.11	5.11	0.75
PEI TOTAL	16.72	0.29	14.64	5.11	5.11	5.11	0.75
PSD Significant Rate	40	40	100	25	15	10	40
Significant Increase?	**No**	**No**	**No**	**No**	**No**	**No**	**No**

[1]See Table A-9 in the attachment section for an explanation of table values.

The proposed change does not result in significant emissions increases of any regulated NSR pollutants. Therefore, AQR 12.2.1.2 requirements for major modifications are not applicable to the removal of the daily limit.

Potential to Emit Increases for Reasonably Available Control Technology Applicability

NVE requested that the '20 hour per day' operating hour limitation be removed while maintaining the annual limitation of 6,135 hours per year. After careful review of records, DAQ concludes that the daily PTE is not used in any of the analyses associated with air quality regulatory requirements. Specifically, neither the BACT nor the air quality modeling evaluation for the project used this information. Since the proposed change is only removing the daily operation limit and there is no change to the existing annual operation limit, there will be no increase in PTE of any pollutant. Therefore, control technology demonstration requirements are not triggered.

E. Performance Testing

Table III-E-1: Performance Testing Dates

EU	Initial Performance Test Date
A01/A03 (Turbine Unit 5)	April 25, 26, and 27, 2011
A02/A04 (Turbine Unit 6)	April 25, 26, and 27, 2011
A09 (Turbine Unit 4)	April 24, 2006
53301 (Turbine Unit 3)	June 5, 6, and 7,1995

Performance testing has been required to assure permitted emission limits are not exceeded. Current DAQ practice is to not require subsequent performance testing if CEMS and annual RATA are required. HAS has CEMS for NO_x and CO for all four turbine units (EUs: 53301, A09, A01/A03, and A02/A04). PM_{10}, VOC and SO_2 are not pollutants of high concern because these turbines combust only natural gas. Furthermore, EUs: 53301, A01/A03, and A02/A04 do not use control technology for these pollutants and EU: A09 does not use control technology for PM_{10} and SO_2. Additionally, PM_{10} and VOC emissions have historically tested below the permit limits. For these reasons, performance testing is not required for these pollutants. Should the Control Officer require performance testing, the protocol requirements are shown in Table III-D-2.

Table III-E-2: Performance Testing Protocol Requirements for Turbines

Test Point	Pollutant	Method (40 CFR Part 60, Appendix A & 40 CFR Part 51, Appendix M)
Turbine Exhaust Outlet Stack	NOx	Chemiluminescence Analyzer (EPA Method 7E)
Turbine Exhaust Outlet Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	---	EPA Methods 1, 2, 3

F. Emissions Monitoring

The purpose of CEMS is to ensure equipment and/or processes are operated so as not to exceed the permitted emission limits. CEMS is a compliance tool for both the agency and the Permittee.

For HAS, CEMS measures NO_X, CO, and O_2 or CO_2 emissions (in ppm) from the exhaust stacks of all four Turbine Units (EUs: 53301, A09, A01/A03, and A02/A04) at least once every 15 minutes. NO_X and CO (in ppm) are monitored and recorded in 3-hour rolling averages. Also for NO_x and CO, hourly and consecutive 12-month period mass emissions (in pounds) are recorded with CEMS data. Annual RATA for each CEMS unit is required to ensure the monitoring system is operating properly.

Quarterly visual emission checks, on a plant-wide basis, are also required to ensure compliance with opacity limits on the emission units.

Increment

HAS is a major source in Hydrographic Area 216 (Garnet Valley). Permitted emission units include four turbines, three generators, one fire pump, and one air cooler. 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.

DAQ modeled the source using AERMOD to track the increment consumption. Stack data submitted by the applicant were supplemented with information available for similar emission units. Five years (2011 to 2015) of meteorological data from the McCarran Station were used in the model. U.S. Geological Survey National Elevation Dataset terrain data were used to calculate elevations. Table III-F-1 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.

Table III-F-1: PSD Increment Consumption

Pollutant	Averaging Period	Source's PSD Increment Consumption ($\mu g/m^3$)	Location of Maximum Impact	
			UTM X (m)	UTM Y (m)
SO_2	3-hour	34.01[1]	688434	4033441
SO_2	24-hour	12.32[1]	688362	4033377
SO_2	Annual	1.99	688233	4034080
NO_X	Annual	2.68	688233	4034080
PM_{10}	24-hour	22.79[1]	688362	4033377
PM_{10}	Annual	3.43	688233	4034080

[1] Highest Second High Concentration.

IV. REGULATORY REVIEW

This section of the TSD is limited to the regulatory review applicable to the emission units addressed in this permitting action.

A. Local Regulatory Requirements

DAQ has determined that the following public laws, statutes, and associated regulations are applicable:

1. CAAA (authority: 42 U.S.C. § 7401, et seq.);
2. Title 40 of the CFR, including 40 CFR Part 70 and others;
3. Chapter 445 of the NRS, Sections 401 through 601;
4. Portions of the AQR included in the SIP for Clark County, Nevada. SIP requirements are federally enforceable. All requirements from ATC permits issued by DAQ are federally enforceable because these permits were issued pursuant to SIP-included sections of the AQR; and
5. Portions of the AQR not included in the SIP. These locally applicable requirements are locally enforceable only.

B. Federally Applicable Regulations

40 CFR Part 60 (NSPS), Subpart A—General Provisions

40 CFR Part 60.7: Notification and record keeping.

Discussion: This regulation requires notification to DAQ of modifications, opacity testing, records of malfunctions of process equipment and/or continuous monitoring device, and performance test data. These requirements are found in the Part 70 Operating Permit in Section III. DAQ requires records to be maintained for five years, a more stringent requirement than the two years required by 40 CFR Part 60.7.

40 CFR Part 60.8: Performance tests.

Discussion: These requirements are in Section III-D of the Part 70 Operating Permit. Notice of intent to test, applicable test methods, acceptable test method operating conditions, and the requirement for three runs are outlined in this regulation. DAQ requirements for initial performance testing are identical to 40 CFR Part 60.8. DAQ may require subsequent performance testing on emission units. More discussion is in this document under the “Compliance” section.

40 CFR Part 60.11: Compliance with standards and maintenance requirements.

Discussion: AQR 26 is more stringent than the federal opacity standards, setting a maximum of 20 percent obscurity for a period of more than 6 consecutive minutes. Harry Allen Station shall operate in a manner consistent with this section of the regulation. Subpart GG of 40 CFR Part 60 also requires fuel monitoring and sampling to meet a standard. Subpart GG requirements are in the Part 70 Operating Permit.

At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected source including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

This is addressed in the Part 70 Operating Permit.

40 CFR Part 60.12: Circumvention.

Discussion: This prohibition is addressed in the Part 70 Operating Permit. There is also a local rule, AQR 80.1.

40 CFR Part 60.13: Monitoring requirements.

Discussion: This section requires that CEMS meet Appendix B and Appendix F standards of operation, testing, and performance criteria. Section III-C of the Part 70 Operating Permit 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, recording time, RATA waivers and malfunctions.

40 CFR Part 60, Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

40 CFR Part 60.40b: Applicability and designation of affected facility.

Discussion: The provisions of this subpart are applicable as the duct burners (EUs: A03 and A04) have rated capacities of 173 MMBtu/hr per unit.

40 CFR Part 60.42b : Standard for sulfur dioxide (SO_2).

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

40 CFR Part 60.43b: Standard for particulate matter (PM).

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

40 CFR Part 60.44b: Standard for nitrogen oxides (NO_X).

Discussion: The permitted limit of 2 ppm NOx is more stringent than the limit set in this section.

40 CFR Part 60, Subpart GG—Standards of Performance for Stationary Gas Turbines

40 CFR Part 60.330: Applicability and designation of affected facility.

Discussion: The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired. Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of 40 CFR Part 60.332. *[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987]*

Turbine Units 3, 4, 5 and 6 (EUs: 53301, A09, A01/A03, and A02/A04) commenced construction after October 3, 1977, and are therefore subject to this subpart.

40 CFR Part 60.332: Standard for nitrogen oxides (NOx limits using the F formula).

Discussion: NV Energy is permitted such that Turbine Units 5 and 6 shall be limited to 1,540 MMBtu/hr, Turbine Unit 3 shall be limited to 873.1 MMBtu/hr, and Turbine Unit 4 shall be limited to 1,060 MMBtu/hr, based on the lower heat value of natural gas. The NO_x limit established as BACT for Turbine Units 5 and 6 is 2.0 ppmvd, Turbine Unit 3 is limited to 9.0 ppmvd, Turbine Unite 4 is limited to 5.0 ppmvd and are within the F formula provisions of the subpart. This requirement has been met.

40 CFR Part 60.333: Standard for sulfur dioxide.

Discussion: The sole use of pipeline-quality natural gas with total sulfur content less than 0.5 grains per 100 dscf satisfies this requirement.

40 CFR Part 60.334: Monitoring of operations.

Discussion: The source installed, calibrated, maintains and operates a continuous monitoring system.

40 CFR Part 60.335: Test methods and procedures.

Discussion: These requirements are found in the conditions for performance testing found in the Part 70 Operating Permit.

40 CFR Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

40 CFR Part 60.4200: Applicability Determination.

Discussion: The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) with a displacement less than 30 liters per cylinder where the model year is 2007 or later, for engines that are not fire pumps, and July 1, 2006, for ICE certified by National Fire Protection Association as fire pump engines. This subpart applies to the diesel fire pump (EU: A11).

40 CFR Part 60.4202: Emission Standards for Owners and Operators.

Discussion: The operator of the stationary CI ICE must provide the manufacturer certification of the emission standards specified in this subpart. These requirements are addressed in the Part 70 Operating Permit.

40 CFR Parts 60.4206 and 60.4211: Compliance Requirements.

Discussion: The operator of the stationary CI ICE must operate and maintain CI ICE that achieve the emission standards according to the manufacturer's written instructions and procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine. These requirements are addressed in the Part 70 Operating Permit.

40 CFR Part 60.4214: Reporting and Recordkeeping Requirements.

Discussion: The operator of the CI ICE shall keep records that include: engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; emission control equipment; and fuel used. If the stationary CI internal combustion is a certified engine, the owner or operator shall keep documentation from the manufacturer that the engine is certified to meet the emission standards. These requirements are addressed in the Part 70 Operating Permit.

40 CFR Part 60, Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

40 CFR Part 60.4300: What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Discussion: All four stationary combustions turbines permitted through this Part 70 Operating Permit commenced construction, modification or reconstruction before February 18, 2005. Therefore, Subpart KKKK will be applicable to this regulation after the upgrade is completed. Therefore, Subpart KKKK is applicable for upgraded turbines.

Therefore, the modified combustion turbines will be subject to the requirements of 40 CFR Part 60, Subpart KKKK. Under 40 CFR Part 60.4305(a), the requirements of this subpart also apply to the duct burners associated with the CCCTs. However, per 40 CFR Part 60.4305(b), the duct burners and HAS will be exempt from the requirements of 40 CFR Part 60, Subpart Da, after the proposed CTUP is completed.

The following NSPS limitations will apply to the two combustion turbines upon completion of the CTUP.

(a) Comply with the NO_X emission limit of 15 ppm at 15 percent 0_2 or 0.43 lb/MWh (for combustion turbine firing natural gas with heat input greater than 850 MMBtu per hour) on a thirty (30) unit operating day rolling average basis. (40 CFR §60.4320 and Table 1, 40 CFR §60.4350 (h))

(b) Comply with the alternate NO_X emission limit of 96 ppm at 15 percent 02 or 4. 7 lb/MWh (for combustion turbine firing natural gas with output greater than 30 MW) 30 unit operating day rolling average basis when combustion turbines are operating at less than 75% of peak load (40 CFR §60.4320 and Table 1, 40 CFR §60.4350(h))

(c) Comply with the SO_2 emission limits of 0.90 pounds per megawatt-hour gross output, or not burn any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input. (40 CFR §60.4330)

(d) Compliance requirement - The combined cycle combustion turbines, SCR, oxidation catalysts, and monitoring equipment must be operated and maintained in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. (40 CFR §60.4333)

(e) Option to use a NO_X continuous emissions monitoring system (CEMS). HAS will use the existing CEMS installed, certified and operated in accordance with 40 CFR Part 75 Appendix A. (40 CFR §60.4335(b) and 60.4345(a))

(f) The requirement to monitor fuel sulfur for SO2 monitoring does not apply if potential sulfur emissions expressed as SO_2 are less than 0.060 lb/MMBtu. HAS proposes to use fuel tariff sheet or purchase contract information or representative fuel sampling performed per 40 CFR 75 Appendix D to show that fuel sulfur will comply with the applicable limit. (40 CFR §§60.4360 and 60.4365)

(g) HAS proposes to use NO_X CEMS RATA as the initial NO_X performance test. (40 CFR §60.4405)

(h) No annual performance test is required due to the presence of NO_X CEMS. (40 CFR §60.4340(b)(1))

(i) Comply with the reporting requirements in 40 CFR § 60.4375 regarding excess emissions and monitor downtime.

40 CFR Part 63, Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

40 CFR Part 63.6585: Applicability Determination.

Discussion: The provisions of this subpart are applicable to owners and operators of stationary reciprocating internal combustion engines (RICE) at major or area sources of HAP. HAS has three emergency generators (EUs: A07, A08 and 53302). HAS is an area source of HAP and is considered an industrial source so the exemption from requirements for existing residential, commercial or institutional emergency engines (as defined in the rule) does not apply. Numeric emission standards are not applied to these emergency engines, however, operational limitations, management practices and record keeping are required. The fire pump engine (EU: A11) 40 CFR 63, Subpart ZZZZ requirements are met by complying with 40 CFR Part 60, Subpart IIII.

40 CFR Part 63.6603: Compliance Requirements.

Discussion: Owners and operators of existing emergency RICE must install an hour meter on the engine to demonstrate that the operating limitations imposed by the definition of an emergency generator are being met (Table 2b of the subpart). Records must be kept to demonstrate the management practices are being followed (Table 2d of the subpart). These requirements are addressed in the Part 70 Operating Permit.

40 CFR Part 64, Compliance Assurance Monitoring

40 CFR Part 64.2: Applicability.

Discussion: The only emission units that emit pollutants above the major source threshold are 53301, A09, A01/A03 and A02/A04 Turbine Units 3, 4, 5, and 6. CAM does not apply for any other emission units included in this Part 70 Operating Permit.

CAM does not apply to Turbine Unit 3 because the permit specifies a continuous compliance determination for the NO_x limitation in the form of a CEMS, required for 40 CFR Part 60 and Part 75 compliance. The CAM Rule does not apply to this unit for CO, SO_2, PM_{10}, VOC, or HAPs based on the applicability statement in 40 CFR Part 64.2(a)(2): no control device is used to achieve compliance for any of these pollutants. This unit is also exempt from the CAM Rule for NO_x and SO_2 based on the exemption at 40 CFR Part 64.2(b)(1)(iii) for Acid Rain Program requirements.

Turbine Unit 4 is exempt from the CAM Rule for NO_x and CO based on the exemption at 40 CFR Part 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 40 CFR Part

60 and Part 75 compliance. The CAM Rule does not apply to this unit for SO_2, PM_{10}, or HAPs based on the applicability statement at 40 CFR Part 64.2(a)(2): no control device is used to achieve compliance for any of these pollutants. The CAM Rule does not apply to this unit for VOC based on the applicability statement at 40 CFR Part 64.2(a)(3): the unit does not have potential pre-control device VOC emissions that are equal to or greater than the major source threshold. This unit is also exempt from the CAM Rule for NOx and SO_2 based on the exemption at 40 CFR Part 64.2(b)(1)(iii) for Acid Rain Program requirements.

CAM does not apply to Unit 5 and 6 because the permit specifies a continuous compliance determination for the NOx and CO limitations in the form of a CEMS, required for 40 CFR Part 60 and Part 75 compliance. The CAM Rule does not apply to these units for SO_2, PM_{10}, VOC, or HAPs based on the applicability statement in 40 CFR Part 64.2(a)(2): no control device is used to achieve compliance for any of these pollutants. These units are also exempt from the CAM Rule for NOx and SO_2 based on the exemption in 40 CFR Part 64.2(b)(1)(iii) for Acid Rain Program requirements.

40 CFR Part 72, Acid Rain Permits Regulation

Subpart A—Acid Rain Program General Provisions

40 CFR Part 72.6: Applicability.

Discussion: Harry Allen Station gas turbines are defined as utility units in the definitions for 40 CFR Part 72; therefore, the provisions of this regulation apply.

40 CFR Part 72.9: Standard Requirements.

Discussion: Harry Allen Station has applied for all of the proper permits under this regulation.

Subpart B—Designated Representative

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

40 CFR Part 73, Acid Rain Sulfur Dioxide Allowance System

Discussion: Harry Allen Station is an affected source pursuant to 40 CFR Part 72.6 of this chapter because gas turbines fit the definition of utility units; therefore, this regulation shall apply.

Subpart B—Allowance Allocations

Discussion: Harry Allen Station is listed on the Phase II table; however, no allowance amount is listed in the table, so it will not have an initial allocation per 40 CFR Part 73.10.

Subpart C—Allowance Tracking System

Discussion: Harry Allen 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, Harry Allen 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 source; therefore, this subpart does not apply.

40 CFR Part 75, Continuous Emission Monitoring

Discussion: Harry Allen Station is subject to the acid rain emission limitations of 40 CFR Part 72; therefore, the source is subject to the monitoring requirements of this regulation.

Each turbine unit has been equipped with both a NO_X CEMS and diluent oxygen monitors. Each turbine unit is also equipped with a fuel flow monitor. Each turbine unit also has a CO CEMS. The data from the CEMS are used to provide quarterly acid rain reports to both EPA and DAQ.

All required monitoring plans, RATA testing protocols, and certification testing reports have been provided to EPA and DAQ.

V. PERMIT SHIELD

Compliance with the terms contained in this permit shall be deemed compliance with the following applicable requirements in effect on the date of permit issuance:

Table V-1: Applicable Requirements Related to Permit Shield

Citation	Title	Permit Condition#
AQR 14.1(b)(40), Subpart GG	NSPS – Stationary Gas Turbines	III-C(3)(k)

Table V-2: Streamlined Requirements Related to Permit Shield (Natural Gas-Fired)

EU	Regulation (40 CFR)	Pollutant	Reg. Std.	Permit Limit	Value Comparison			Streamlining Statement for Shielding Purposes
					Std Val in Units of Permit Limit	Permit Limit Value	Is Permit Limit Equal or More Stringent?	
A01, A02, A09, 53301	60.333 (GG)	SO_2	0.8% sulfur by weight (8,000 ppmv)	0.5 grains sulfur per 100 scf	260[1]	0.5	Yes	The permit limit is more stringent than the standard, based on both concentration and averaging time, therefore the facility should be shielded from the standard.

[1]Sulfur content was converted from percent by weight to grains (gr) per 100 standard cubic feet (scf) as follows: 0.8% sulfur = 56 gr per pound (lb) natural gas. Assuming an average molecular weight of 18 lb/lb-mol for natural gas = $2.14 * 10^3$ scf. Lastly. 56 gr sulfur per $2.14 * 10^3$ scf natural gas equates to 260 gr/100 scf.

After completion of the upgrade project and start-up of turbines EUs: A01 and A02; this permit shield will not be applicable for NSPS GG.

VI. COMPLIANCE

A. Compliance Certification

1. Regardless of the date of issuance of this Part 70 Operating Permit, the schedule for the submittal of reports to DAQ shall be as follows:

Table VI-A-1: Reporting Schedule

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 Emissions	As required	Within 24 hours of the permittee learning of the event
Report of Malfunctions, Startup, Shutdowns, or Deviations with Excess Emissions	As required	Within 72 hours of notification
Deviation Report without Excess Emissions	As required	Along with semiannual reports
Performance Testing	As required	Within 60 days from end of test

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

2. A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods.

3. A schedule for submission of compliance certifications during the permit term.

4. A statement indicating the source's compliance status with any applicable enhanced monitoring and compliance certification requirements of the Act.

B. Summary of Monitoring for Compliance

Table VI-B-1: Compliance Monitoring

EU	Process Description	Monitored Pollutants	Applicable Subsection	Requirements	Compliance Monitoring
A01/03 A02/A04	Combustion Turbine Units 5 and 6	PM_{10}, NO_x, CO, SO_2, VOC	AQR 12.5	Annual emission limits.	Recordkeeping of fuel use. Compliance for emissions not monitored by CEMS shall be based on fuel consumption and emission factors. SO_2 will be monitored through sulfur content in the fuels.
A01/03 A02/A04 (Before Completion of Project)	Combustion Turbine Units 5 and 6	CO, NO_x	AQR 12.5 and 40 CFR 60, Subpart GG	Annual and short-term emission limits. Fuel consumption recordkeeping and reporting.	CEMS for NO and CO. Recordkeeping of fuel consumption is required for compliance demonstration.
A01/03 A02/A04 (After Completion of Project)	Combustion Turbine Units 5 and 6	CO, NO_x	AQR 12.5 and 40 CFR 60, Subpart KKKK	Annual and short-term emission limits. Fuel consumption recordkeeping and reporting.	CEMS for NO and CO. Recordkeeping of fuel consumption is required for compliance demonstration.
A01/03 A02/A04 (Before Completion of Project)	Combustion Turbine Units 5 and 6	SO_2	40 CFR 60, Subpart GG	Natural gas sulfur content limited by 0.50 grains per 100 scf.	Recordkeeping of sulfur content.
A01/03 A02/A04 (After Completion of Project)	Combustion Turbine Units 5 and 6	SO_2	40 CFR 60, Subpart KKKK	0.060 lb per MMBtu of heat input	Purchase contract or sampling
A01/A02	Combustion Turbine Units 5 and 6		Permit limit	Annual MMBtu	Monthly, 12-month consecutive
A03/A04	Duct burners		Permit limit	Annual MMBtu	Monthly, 12-month consecutive
53301	Turbine #3		Permit limit	Hours	Monthly, 12-month consecutive

EU	Process Description	Monitored Pollutants	Applicable Subsection	Requirements	Compliance Monitoring
A09	Turbine #4		Permit limit	Hours	Monthly, 12-month consecutive
All turbines	All turbines		Permit condition	Testing/tuning events	Recordkeeping of occurrences
All turbines	All turbines		Permit condition	Startup, shutdown cycles	Recordkeeping of dates and times
A01/A02	Combustion Turbine Units 5 and 6		Permit condition	Records of the emissions (in tpy) of any regulated NSR pollutant that could increase as a result of the CTUP for a period of 10 years following resumption of regular operations after the change	Recordkeeping
53301	Turbine Unit 3	CO, NO_x	AQR 12.5 and 40 CFR 60, Subpart GG	Annual and short-term emission limits. Fuel consumption recordkeeping and reporting.	CEMS for NO and CO. Recordkeeping of fuel consumption is required for compliance demonstration.
53301	Turbine Unit 3	SO_2	40 CFR 60, Subpart GG	Natural gas sulfur content limited by 0.50 grains per 100 scf.	Recordkeeping of sulfur content.
A09	Turbine Unit 4	PM_{10}, NO_x, CO, SO_2, VOC	AQR 12.5	Annual emission limits.	Recordkeeping of fuel use. Compliance for emissions not monitored by CEMS shall be based on fuel consumption and emission factors. SO_2 will be monitored through sulfur content in the fuels.
A09	Turbine Unit 4	CO, NO_x	AQR 12.5 and 40 CFR 60, Subpart GG	Annual and short-term emission limits. Fuel consumption recordkeeping and reporting	CEMS for NO and CO. Recordkeeping of fuel consumption is required for compliance demonstration.
A09	Turbine Unit 4	SO_2	40 CFR 60, Subpart GG	Natural gas sulfur content limited by 0.50 grains per 100 scf.	Recordkeeping of sulfur content.

EU	Process Description	Monitored Pollutants	Applicable Subsection	Requirements	Compliance Monitoring
A07, A08, 53302, and A11	Emergency Generator and Emergency Fire Pump Engines	Opacity	AQR 26	Opacity 20%	Quarterly visual observations of opacity shall be made while operating. Immediate logging of any opacity noted and correction of opacity exceedance.
A07, A08, 53302	Emergency Generator Engines	HAP, SO_2	40 CFR 63, Subpart ZZZZ, and former AQR 29	Management practices: Sulfur in diesel fuel limited to 0.05% by weight.	Recordkeeping of hours of operation and fuel sulfur content.
A11	Emergency Fire Pump Engine	NOx, CO, VOC, PM10, SO_2	AQR 12.5 and 40 CFR 60, Subpart IIII	Emission limitations based upon hours of operation for testing and maintenance. Sulfur in diesel fuel limited to 15 ppm.	Recordkeeping of hours of operation. Calculated emissions based on manufacturer's data, AP-42, and fuel. Manufacturer's emission data. Records of fuel sulfur content.

ATTACHMENTS:

Table A-1: Applicability/SDE PTE (tons per year)

	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAP
Turbine/Engines	151.40	151.40	311.73	279.99	14.72	64.93	5.65
Insignificant Activities	0.72	0	0	0	0	0	0
Total	152.12	151.40	311.73	279.99	14.72	64.93	5.65

Table A-2: Wet Surface Air Cooler Calculation

EU	Description	Drift Loss % (1)	Flow Rate (gal/min)	TDS (mg/l)	Hours of Operation		PM10 Emissions	
					hr/day	hr/yr	lb/hr	ton/yr
C01	Wet Surface Air Cooler	0.0005%	2800	50000	24	8760	0.16	0.72
							0.16	0.72

Note: mg/l is equivalent to ppm.
(1) You must enter the manufacturer's value, including the zero before the decimal point.

Table A-3: Baseline Actual Emissions

Affected Units			NOx	SO_2*	CO	PM*	PM_{10}*	$PM_{2.5}$*	VOC*
BAE									
Year	Hours	MMBtu							
2020	1111	716,156	12.56	0.54	11.66	5.56	5.56	5.56	0.83
2021*	1030	684,319	12.74	0.67	11.15	5.15	5.15	5.15	0.77
Average			12.65	0.61	11.41	5.36	5.36	5.36	0.80

Projected HHV - 873.1 x 1.11 = 969.14

Table A-4: Verified Maximum Annual Average Heat Input Rate Calculation (With)

Equipment	Heat Rate (MMBtu/hr)	Condition (hr/yr)	Total (MMBtu/yr)
Turbine #3	969.14	6,135	5,945,673.9
		Total	**5,945,673.9[1]**

[1]HAS's used 965 MMBtu/hr in their calculations which came up with a value of 5,920,307 MMBtu/year. The value listed in Table A-4 was used below in the PAE calculation with.

Table A-5: Verified Maximum Annual Average Heat Input Rate Calculation (Without)

Equipment	Heat Rate (MMBtu/hr)	Condition (hr/yr)	Total (MMBtu/yr)
Turbine #3	969.14	5,111	4,953,274.5
		Total	**4,953,274.5[1]**

[1]HAS's used 965 MMBtu/hr in their calculations which came up with a value of 4,932,142 MMBtu/year. The value listed in Table A-5 was used below in the PAE calculation without.

Table A-6: Projected Actual Emissions with (tpy)

PAE with

Pollutant	Heat Rating (MMBtu/yr)	EF (lb/MMBtu)	PTE (lb/2000)
	Turbine (53301)		
NO_x	5,945,673.9	0.0337	100.18
SO_2	5,945,673.9	0.0006	1.78
CO	5,945,673.9	0.0295	87.70
PM	5,945,673.9	0.0103	30.62
PM_{10}	5,945,673.9	0.0103	30.62
$PM_{2.5}$	5,945,673.9	0.0103	30.62
VOC	5,945,673.9	0.0015	4.36

Table A-7: Projected Actual Emissions without (tpy)

PAE without

Pollutant	Heat Rating (MMBtu/yr)	EF (lb/MMBtu)	PTE (lb/2000)
	Turbine (53301)		
NO_x	4,953,274.5	0.0337	83.46
SO_2	4,953,274.5	0.0006	1.49
CO	4,953,274.5	0.0295	73.06
PM	4,953,274.5	0.0103	25.51
PM_{10}	4,953,274.5	0.0103	25.51
$PM_{2.5}$	4,953,274.5	0.0103	25.51
VOC	4,953,274.5	0.0015	3.71

Table A-8: Excludable Emissions Calculations (tpy)

EU	NO_X	SO_2	CO	PM	PM_{10}	$PM_{2.5}$	VOC
PAE without							
53301	83.46	1.49	73.06	25.51	25.51	25.51	3.71
BAE							
53301	12.65	0.61	11.41	5.36	5.36	5.36	0.80
Difference	70.81	0.88	61.65	20.15	20.15	20.15	2.91

The excludable emissions for the project-affected EUs shown in Table A-8 were calculated by subtracting the BAE from the PAE without.

Table A-9. Project Emissions Increase (tpy)

Affected Units	NO_x	SO_2	CO	PM	PM_{10}	$PM_{2.5}$	VOC
Projected Actual Emissions (tpy)							
53301	100.18	1.78	87.70	30.62	30.62	30.62	4.46
Baseline Actual Emissions (tpy)							
53301	12.65	0.61	11.41	5.36	5.36	5.36	0.80
Excludable Emissions							
53301	70.81	0.88	61.65	20.15	20.15	20.15	2.91
PEI	**16.72**	**0.29**	**14.64**	**5.11**	**5.11**	**5.11**	**0.75**

The PEI shown in Table A-9 was calculated by subtracting the EE and BAE from the PAE with.