TECHNICAL SUPPORT DOCUMENT

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

SUBMITTED BY

SAGUARO POWER COMPANY

for

SAGUARO POWER COMPANY

Part 70 Operating Permit Number: 393
SIC Code - 4911: Electric Utility Services

Clark County
Department of Air Quality and Environmental Management
Permitting Section

March 2009

EXECUTIVE SUMMARY

The Saguaro Power Company (SPC) is located at 8000 West Lake Mead Parkway, Henderson, Nevada 89015, in the Las Vegas Valley airshed, hydrographic basin number 212. Hydrographic basin 212 is basic nonattainment for CO, PM_{10}, and ozone, and PSD for all other regulated air pollutants.

Saguaro Power Company (SPC) operates two General Electric (GE), 35.0 MW, natural gas combustion turbine generators (CTGs) with heat recovery steam generators (HRSG), a 23.1 MW extraction/condensing steam turbine generator system and two waste heat recovery steam generators with four, 25 MMBtu/hr each supplemental firing duct burners. These units are permitted to fire on hydrogen gas, natural gas and fuel No. 2 distillate oil. There are also two auxiliary boilers that are used to provide continuous steam supply. In addition, SPC operates a cooling tower, two diesel fired turbine starter engines, a fuel oil storage tank, and an ammonia storage and injection system. All generating and support processes at the site are grouped under the Standard Industrial Classification (SIC) 4911 – Electric Services (NAICS: 22111 - Electric Power Generation). The potential emissions for the source are shown in the table below.

Table 1: Maximum Facility PTE (tons per year)

PM_{10}	NO_X	CO	SO_x	VOC	HAP	NH_3
37.94	165.46	90.23	11.30	13.86	8.95	45.01

Clark County Department of Air Quality and Environmental Management (DAQEM) has delegated authority to implement the requirements of the Part 70 operating permit program. The SPC emits particulate matter (PM_{10}), carbon monoxide (CO), oxides of nitrogen (NO_x), oxides of sulfur (SO_x), volatile organic compounds (VOCs), hazardous air pollutants (HAP), and ammonia (NH_3). The source is a major source for NO_X, CO, and NH_3.

Initial Part 70 Operating Permit was issued on February 29, 2000; Part 70 OP Administrative Revision One was issued on November 8, 2001; and ATC/OP Modification 7, Revision 0, was issued on March 19, 2008. DAQEM received the renewal Title V application on June 18, 2003. Based on the information submitted by the applicant and a technical review performed by the DAQEM staff, the DAQEM proposes the renewal of a Part 70 Operating Permit to Saguaro Power Company.

This Technical Support Document (TSD) accompanies the proposed Part 70 Operating Permit for Saguaro Power Company.

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I. SOURCE INFORMATION

A. General

Permittee	Saguaro Power Company
Mailing Address	8000 West Lake Mead Parkway Henderson, NV 89015
Contacts	Monte Ash, General Manager
Phone Number	(702) 558-1131
Fax Number	(702) 564-2735
Source Location	8000 West Lake Mead Parkway Henderson, NV 89015
Hydrographic Area	212
Township, Range, Section	T22S, R62E, Section 11, 12, 13, 14
SIC Code	4911 – Electric Services
NAICS Code	22111 - Electric Power Generation

B. Description of Process

Saguaro Power Company (SPC) produces electrical power and thermal energy (steam). The electrical energy is transmitted to Nevada Power Company electrical grid for distribution to consumers. The steam is sold to the manufacturing facilities. The SPC is defined as a cogeneration facility because it generates and sales two useful forms of energy.

SPC operates two General Electric (GE), 35.0 MW, natural gas combustion turbine generators (CTGs) with heat recovery steam generators (HRSG), a 23.1 MW extraction/condensing steam turbine generator system and two waste heat recovery steam generators with four, 25 MMBtu/hr each supplemental firing duct burners. These units are permitted to fire on hydrogen gas, natural gas and fuel No. 2 distillate oil. There are also two auxiliary boilers that are used to provide continuous steam supply. In addition, SPC operates a cooling tower, two diesel fired turbine starter engines, a fuel oil storage tank, and an ammonia storage and injection system.

Fuel is supplied to the combustion chambers where it is mixed with the compressed air and the mixture is ignited. The thermal energy of the combustion gases exiting the combustors is transformed into rotating mechanical energy as the gases expand through the turbine sections of the CTGs. The rotating mechanical energy is converted into electrical energy via a shaft on each CTG connected to an electrical generator. The high temperature, pressurized gas produced by the combustion expands through the turbine blades, driving the electric generator and the compressor. The rotating mechanical energy generated by the steam turbine is converted into electrical energy via a shaft connected to an electrical generator. The exhaust gases will exit to the atmosphere after leaving the turbine, having already passed through an oxidation catalyst for CO control and selective catalytic reduction (SCR) system for NO_X control. Power cycle heat rejection is accomplished with a cooling tower.

The Thermal-Dynamics cooling tower is a 3-cell mechanical draft unit a circulation rate of 6,395 gallons per minute per cell or 19,185 gallons per minute total. Total dissolved solids are limited to 3,800 ppm with operation allowed 8,760 hours annually. The tower is fitted with high efficiency mist eliminators rated at 0.0006 percent.

The SPC emits particulate matter (PM_{10}), carbon monoxide (CO), oxides of nitrogen (NO_x), oxides of sulfur (SO_x), volatile organic compounds (VOCs), hazardous air pollutants (HAP), and ammonia (NH_3). Saguaro is a major source for NO_X, CO, and NH_3.

The SPC NO_x and CO emissions are monitored with continuous emission monitoring system (CEMS). The ammonia (NH_3) parametric emissions monitoring system (PEMS) is used to demonstrate compliance with ammonia emission limits. The monitoring system generates a log of data and provides alarm signals to the control room when the level of emissions exceeds preselected limits.

C. Permitting History

The SPC is regulated by the Clark County Department of Air Quality and Environmental Management (DAQEM), and has Title V permit. The SPC facility is a major source for NO_x, CO, and NH_3. Initial Part 70 Operating Permit was issued on February 29, 2000; Part 70 OP Administrative Revision One was issued on November 8, 2001; and ATC/OP Modification 7, Revision 0, was issued on March 19, 2008. DAQEM received the renewal Title V application on June 18, 2003. SPC did not propose any changes to the current Part 70 OP. However, there were few NSR permits issued after the renewal application submission and changes implemented in these permits have to be incorporated into the Part 70 OP.

Table I-C-1: NSR Permits Issued to Saguaro Power Company

Date Issued	Permit Number	Description
11/21/2008	ATC Modification 7, Revision 2	Revision of the existing ATC/OP to describe enforceable limits and the source-wide PTE.
03/19/2008	ATC/OP Modification 7, Revision 0	Modification of the existing ATC/OP included installation of a new super low-NO_x burner and CO oxidation catalyst on Volcano 249 MMBtu/hr auxiliary boiler in order to accommodate the increased throughput.
08/05/2008 (expired on 12/31/2008)	ATC Modification 6, Revision 2	Alternate operating scenario, the modification qualified as a Section 502(b)(10) change to the Part 70 source in accordance with Clark County Air Quality Regulations, Section 19.4.1.8.
10/04/2006	ATC/OP Modification 6, Amendment 1	This amendment of ATC/OP Modification 6 was issued because the previously issued ATC/OP Mod 6 was never signed by the source and therefore the source did not have a valid ATC/OP.
06/21/2006	ATC/OP Modification 6	Modification of the ATC/OP included update of HAP emissions for all emissions units, update of SO_x emissions for the turbines, update of emission calculations, inclusion of VOC deminimus units, removal of the portable diesel generator, and update of ammonia PEMS calculations. Permit was never signed by the source.

Date Issued	Permit Number	Description
06/16/1999	ATC/OP Modification 5	Modification of the ATC/OP included update in calculation method of PTE based on CEMS, performance testing, and records of hours of operation. The seasonal emission limits were replaced with one year-round limit.
12/10/1997	OP Modification 4	Modification of the Section 16 OP included replacement of the 136.4 MMBtu/hr natural gas fired boiler for steam generation with a new 247.0 MMBtu/hr boiler.
07/24/1997	ATC Modification 4	Section 12 ATC (A393) Authority to Construct – Replacement of existing 136.4 MMBtu/hr natural gas fired boiler for steam generation with a new 247.0 MMBtu/hr boiler.
04/12/1996	Temporary OP Modification 3	Section 16 OP (A039308) Addition of diesel power generator with time limit conditions; record keeping, and reporting.
03/31/1995	OP Modification 2	Section 16 OP (A58010) Addition of Nebraska natural gas or hydrogen fired boiler for steam generation with time limit conditions; record keeping, and reporting. The emission offset requirement was included in the permit.
01/05/1995	ATC Modification 2	Section 12 ATC (A0393) Authority to Construct - Nebraska natural gas or hydrogen fired boiler for steam generation.
04/02/1993	OP Revised	Section 16 OP (A39301 through A39307) Revised permit conditions for two GE turbines, two diesel starter engines, lime storage silo, soda ash storage silo, and auxiliary boiler.
06/18/1992	OP	Section 16 OP (A39301 and A39302) Operating permit with conditions for two GE turbines, a steam turbine, two HRSG with supplemental duct firing and a SCR for NO_x control.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39307) Nebraska Boiler, Model N38-7-89, 190.5 MMBtu/hr SPC OP, indicates no conditions; no record keeping, and no reporting.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39306) Lime Silo SPC OP, indicates no conditions; no record keeping, and no reporting.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39305) Soda Ash Silo SPC OP, indicates no conditions; no record keeping, and no reporting.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39304) Detroit Diesel Engine, Model 7123 – 7300, 600 hp (# 1) SPC OP, indicates no conditions; no record keeping, and no reporting.
11/22/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39303) Detroit Diesel Engine, Model 7123 – 7300, 600 hp (# 2) SPC OP, indicates no conditions; no record keeping, and no reporting.
11/21/1991	ATC Modification 1	Authority to Construct, Modification 1, addition of two 600 hp diesel engines, soda ash storage silo, and lime silo.
07/25/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39302) GE Frame G5418Turbine (#2) SPC OP, natural gas, with SCR, indicates no conditions; no record keeping, and no reporting.
07/25/1991	Section 8 OP (yellow ticket)	Section 8 OP (A39301) GE Frame G5418Turbine (#1) SPC OP, natural gas, with SCR, indicates no conditions; no record keeping, and no reporting.
06/17/1991	ATC	Section 12 ATC (A393) Authority to Construct permit with conditions for two GE turbines, a steam turbine, two HRSG with supplemental duct firing and a SCR for NO_x control.
08/10/1990	ATC	Section 12 ATC (A393) Authority to Construct permit with conditions for two GE turbines, a steam turbine, two HRSG.

On October 9, 2007, SPC applied for modification of the existing ATC/OP. The source requested to increase throughput of the 249 MMBtu/hr Indeck/Volcano boiler (EU: A05) to combust only natural gas and/or a combination of natural gas and hydrogen with the operation limited to 2,181,240 MMBtu/year fuel. SPC proposed to install a new super low-NO_x burner and CO oxidation catalyst in order to accommodate the increased throughput. The equipment manufacturer guarantees an operating emission limit of 12 ppm NO_x when burning natural gas only, as well as mixture of natural gas and hydrogen. In addition, SPC proposed a 1.2 ppm CO emission rate from the boiler. The modification required Lowest Achievable Emission Rate (LAER) for CO as SPC is a major source in the Hydrographic Basin 212 CO Serious Nonattainment area.

The source determined the use of 10 ppm CO burner coupled with an Oxidation Catalyst will drop the CO emissions to 1.2 ppm. These controls are considered LAER for CO. This modification does not trigger offsetting requirements specified in AQR Section 59, the proposed modification changed the boiler status from Dc to Db and requires an installation and operation of a CEMS on the unit.

On July 18, 2008, the source applied for the amendment of the existing ATC/OP. The source requested to authorize a temporary alternative operating scenario. The proposed temporary operating scenario allowed for the operation of the Volcano boiler (EU: A05) beyond the natural gas throughput level of 218,124 MMBtu/year. Consequently, throughput of the 249 MMBtu/hr Volcano boiler (EU: A05) to combust only natural gas and/or a combination of natural gas and hydrogen will be increased to 1,132,452 MMBtu/year (4,548 hours per year at 100% capacity).

To offset the emissions increase, SPC proposed to decrease the allowable hours of operation of each combustion turbine by 3,011 hours per turbine, as compared to the past actual operating hours (actual average of 2006 and 2007). The operating hours for CTG 1 (EU: A01) were limited to 4,950 hours per year and the operating hours for CTG 2 (EU: A02) were limited to 4,476 hours per year. The change potentially reduced the NO_x emissions by 29.04 tons and CO emissions by 5.98 tons, as compared to the actual past emissions. The temporary alternative scenario also reduced VOC, HAP, NH_3, SO_x and PM_{10} emissions.

The modification qualified as a Section 502(b) (10) change to the Part 70 source in accordance with Clark County Air Quality Regulations, Section 19.4.1.8.

Table I-C-2: BACT Determinations for Saguaro Power Company

EU	Description	BACT Technology	BACT Limit
A01, A02	35 MW natural gas-fired electric turbine generators, with HRSG, supplemental duct-firing	Low-NO_X burners, SCR, steam injection, natural gas combustion	10 ppmvd NO_X on 8-hour average at 15% O_2 (natural gas); 17 ppmvd NO_X on 8-hour average at 15% O_2 (fuel oil); 10 ppmvd CO on 8-hour average at 15% O_2 (natural gas and fuel oil).
A03, A04	Detroit Diesel Starter Engines	Turbocharged, Aftercooled, Low sulfur diesel fuel (< 0.05%)	No limit imposed.
A05	Indeck/Volcano Auxiliary Boiler #1; 249 MMBtu/hr	Low-NO_x burners with FGR; CO oxidation system	12 ppmvd NO_X on 3-hour average at 3% O_2; 1.2 ppmvd CO on 3-hour average at 3% O_2.

EU	Description	BACT Technology	BACT Limit
A06	Nebraska Auxiliary Boiler #2; 86 MMBtu/hr	Sole use of pipeline quality natural gas; good combustion practices	30 ppmvd NO_X on 8-hour average at 3% O_2; 400 ppmvd CO on 8-hour average at 3% O_2.
A09a, A09b, A09c	Thermal-Dynamics Towers Inc., Cooling Tower; 19,185 gpm total	Limit of TDS; drift loss eliminators	3,800 mg/L TDS, 0.0006% drift loss.
F05, F05a, F06, F06a	John Zink Model LDR-11-LE Supplemental Duct Burner, 25 MMBtu/hr	Low-NO_X burners, SCR, steam injection, natural gas combustion	10 ppmvd NO_X on 8-hour average at 15% O_2 (natural gas); 17 ppmvd NO_X on 8-hour average at 15% O_2 (fuel oil); 10 ppmvd CO on 8-hour average at 15% O_2 (natural gas and fuel oil).

D. Operating Scenario

Combustion Turbine Generators (CTG)

SPC operates two GE frame 6 (PG6541B) combined-cycle CTGs rated at 34.93 megawatts (at one atmosphere pressure, ambient temperature of 105°F and 16 percent relative humidity). At standard conditions the CTGs maximum heat input is 422 MMBtu/hr (lower heating value). The CTG's primarily fire natural gas but are permitted to fire distillate fuel oil for up to 480 hours per year per CTG. The CTGs are operated as base-load units, and are permitted to operate 365 days per year. The CTG's incorporate steam injection to control oxides of nitrogen (NO_x) emissions.

The CTGs exhaust to a three pressure HRSG that incorporates two sets of duct burners. One duct burner set is capable of firing a maximum of 25 MMBtu/hr (HHV) of hydrogen (supplied by the adjacent chemical manufacturer). The other set of duct burners is capable of firing a maximum of 25 MMBtu/hr of natural gas (HHV). The duct burners (for each CTG) are rated at 50 MMBtu/hr (HHV).

The HRSG's also include selective catalytic reduction systems (SCR) for the control of oxides of nitrogen (NO_x) emissions. The SCR system uses anhydrous ammonia as a reactant in the presence of a catalyst to convert NO_x to elemental nitrogen. The SCR system includes one anhydrous ammonia storage tank with vaporizers, piping, mixing systems, and an injection grid for each CTG.
An exhaust gas blower extracts exhaust gas from the exhaust stacks (for each CTG) for use by the adjacent chemical manufacturer as a source of carbon dioxide. The CTG's design incorporates a diesel-fired starter engine used to start the CTG's. These starter engines are integral to the CTG design and are enclosed within the CTG enclosures.

The CTG's incorporate a system to wash the compressor section of the units with demineralized water or with an aqueous-based cleaning solution. Washes can be performed while the units are operating and during outages. Manufacturers' information doesn't list any HAPs present in the wash solution.

Starter Engines

Each CTG design incorporates a diesel starter engine (EUs: A03 and A04) which provides the necessary power to initiate the start up sequence for the CTG's. These engines are permitted to operate 125 hours per year per engine. The criteria pollutant emissions are based on permitted emission limits. The HAP emission estimates are based on EPA AP-42 emission factors.

Auxiliary Boilers

SPC currently has two auxiliary boilers that supply steam to their customers during periods when the CTG's are not in operation. The larger of the two is a natural gas-fired boiler rated at 249 MMBtu/hr (LHV) heat input (EU: A05). This boiler is permitted to operate up to 8,760 hours per year firing only natural gas and hydrogen gas. This boiler's design incorporates Low-NO_x burners and flue gas recirculation to control NO_X emissions and CO oxidation system for CO control.

The second auxiliary boiler (EU: A06) is rated to produce 70,000 pounds per hour of steam at a heat input of 86 MMBtu/hr (LHV). This boiler is permitted to operate 6,000 hours per year firing only natural gas and/or hydrogen gas. This boiler's design incorporates Low-NO_x burners and flue gas recirculation to control NO_X emissions.

Water Treatment Chemical Storage

The SPC facility operates three water treatment systems: a boiler make-up, a boiler pH and steam drum chemistry system, and a cooling tower water make-up system.

The boiler make-up water treatment system has a primary system which is a leased trailer-mounted ion exchange system used to treat make-up water for steam production. This trailer-mounted system is taken off site for regeneration (by the vendor) and does not emit any pollutants to the atmosphere. A back-up ion exchange-based boiler make-up water system is located on site. This system is permitted, but only used as a back-up system to the primary system. The back-up system is capable of being regenerated using hydrochloric acid and sodium hydroxide. The sodium hydroxide (NaOH) and hydrochloric acid (HCl) are stored as aqueous solutions in closed-top containers. The HCl storage tank vents to a scrubbing system where the gases vented during filling of the tank are bubbled through a container of water, any HCl mist in the vent gas will be absorbed by the water with negligible HCl emitted to the atmosphere.

The second water treatment system is the boiler pH and steam drum chemistry system. This system uses mono-, di-, tri-sodium phosphates, an oxygen scavenging product, and an amine-based product to control the boiler water chemistry. The sodium phosphate products are stored as both dilute aqueous solutions and dry powders in closed-top containers. The oxygen scavenging and amine-based products are stored as dilute liquids in closed-top containers. Product manufacturers report that no regulated pollutants are contained in these products.

The third water treatment system is the cooling tower make-up system. This water treatment system uses lime (CaO), soda ash (Na_2CO_3), and hydrochloric acid to treat the cooling tower make-up water. The calcium oxide and soda ash are stored as solids in storage silos with fabric filter vents. The HCl is used to control pH and is not expected to be emitted. The silos will emit emissions of soda ash and calcium oxide in the form of particulate matter.

Distillate Fuel Oil Firing

In the event of a curtailment of natural gas, the SPC facility is capable of firing fuel oil in the CTGs for up to 480 hours per year per CTG or a total of 960 hours of fuel oil firing per year. These emissions include emission controls for NO_X in the form of steam injection/SCR and include duct burner emissions.

Fuel Oil System

The SPC receives, stores, and transports distillate fuel oil. The fuel oil is stored in a white, 750,000 gallon fixed roof storage tank. The storage tank’s only emission point is an atmospheric vent with a pressure relief valve installed to control vapor emissions. The storage tank’s annual average temperature is 77°F. The emissions are based on EPA AP-42 emission factors (section 4.3-5) and the annual average temperature. All emissions for the fuel oil tank are assumed to be VOC emissions.

The fuel oil is received at an unloading station located outside the main SPC facility to the North. The receiving station consists of a manifold system with capabilities of accepting deliveries from either tanker trucks or rail cars. The manifold is connected to an unloading pump located inside the SPC fence line that pumps the fuel oil from the unloading vessel to the onsite storage tank.

Fuel oil is transferred from the storage tank to the CTGs and starter engines by a pumping system. The pumping system consists of two electric-driven pumps with underground piping. The fuel oil transfer and receiving fugitive emission estimates are based on the maximum allowable fuel oil usage and EPA emission factors for valves, flanges, and pumps.

Cooling Tower

Waste heat is rejected to the atmosphere by a mechanical-draft, three-cell cooling tower. The cooling tower uses the principal of evaporation to reject this heat. In the cooling process, a fraction of the cooling water escapes the cooling tower as cooling tower drift. The SPC cooling tower circulates 9,600,000 pounds per hour of water with a drift rate of 0.0006 percent of the cooling capacity. The cooling tower total dissolved solids (TDS) content is controlled to approximately 3,800 ppm. It is assumed that TDS will become particulate matter when the water mist or drift is emitted from the cooling tower.

Emission estimates for the cooling tower are based on the above data, and assume that the cooling tower is operated 8760 hours per year.

The cooling tower uses gaseous chlorine for biological growth control. The chlorine is injected into a slipstream of water which is mixed with the cooling tower water. The chlorine content of the cooling tower water is controlled to approximately 0.2 ppm (with a maximum chlorine concentration of 0.5 ppm). The SPC facility uses approximately 2.6 tons of chlorine per year or 0.60 pounds per hour. Chlorine reacts with water to form hypochlorus acid (HOCl) which is classified as HAP. A review of available emission factor literature did not reveal emission factors for chlorine or hypochlorus acid from cooling towers. Additionally, given the quantity of chlorine used, and the low drift rate for the cooling tower, the emissions of hypochlorus acid are insignificant.

<u>Natural Gas Conveyance System</u>
The natural gas conveyance system at SPC is comprised of a metering station which is located to the north of the SPC facility, a filtering station, the CTG gas control and metering enclosures, and the HRSG duct burner control and metering skids. These systems contain many valves, flanges, and seals which all leak to a minor extent. The first phase of developing an emission estimate for the natural gas system was to perform a valve, flange, and seal inventory. This inventory was broken down by location and included the metering station, filtration system, the CTG gas control and metering enclosures, and the duct burner skids. The CTG natural gas conveyance systems were primarily underground and were not capable of being inventoried. The valve and flange inventories and EPA emission factors were used to calculate the natural gas emissions. The natural gas emissions were converted into volatile organic compound emissions by assuming that 10 percent of the natural gas is non-methane hydrocarbons (or VOC).

<u>Lubricating Oil System</u>
The CTGs and steam turbine have lubricating (lube) oil systems to provide a constant supply of oil to bearings, gears, and other components requiring lubrication. The oil supply systems are pressurized. The oil in the lubricated components is typically at atmospheric pressure and requires an atmospheric vent. The CTG vents are equipped with a blower and a coalescing mist eliminator. The steam turbine lube oil vent is equipped with a blower and precipitator-type mist eliminator.

As with the natural gas conveyance system, these systems leak to a minor extent. An inventory of the valves and flanges was performed as the basis for the fugitive emission estimates from these lube oil systems. The valve and flange inventory and EPA emission factors were used to estimate the emissions of lube oil. A review of the material data safety sheet for the lube oil determined that the oil contained less than 5 percent (by weight) volatile organic compounds (VOC). The VOC emission estimate was assumed to be 5 percent of the system oil leaks (calculated using the EPA emission factor).

<u>Ammonia Storage and Injection System</u>
The SCR system uses anhydrous ammonia to control NO_X emissions from the CTGs. This ammonia is stored in a pressure vessel (common to both CTGs) and is transported to the SCR control and injection skids via welded piping. A valve and flange inventory and EPA emissions factors were used to estimate the ammonia emission from the ammonia storage and injection system.

<u>Miscellaneous Emissions</u>
SPC plans on painting the entire source within the next five years. Architectural coatings can result in emissions of VOCs. SPC has solicited quotes from painting contractors to provide proposals to paint the facility, and to provide an estimate of the VOC emissions. Based on these estimates, it would require approximately 600 gallons each of primer and top-coat paint with a VOC content of 109 and 207 grams per liter, respectively. The hourly emissions were estimated assuming that the paint would cure over a three-day period and emissions would be constant over the curing period.

The SPC facility conducts maintenance operations requiring the use of a variety of materials and products. These materials include paints, lubricants, cements/adhesives, greases, hydraulic fluids, cutting oils, spray foam, welding rods, fuel oil, contact cleaners, and antifreeze.

These materials are purchased from local vendors and typically range in size from several ounces to gallon size containers. Lubricating oils used in the CTG's and other equipment are stored in larger sized containers (55-gallon drums). Emissions estimates associated with these materials were not performed.

Other activities at the SPC have the potential to generate air emissions. Some of these activities are metal cutting and welding (arc, gas, and plasma), use of pressure washing systems, the water chemistry laboratory, gasoline-powered (less than 5 hp) water pumps, parts cleaning, and glove booth abrasive cleaning. Most of these activities are intermittent in nature and occur infrequently with the exception of the water chemistry lab. The lab uses standard test kits developed by chemical supply companies containing buffer solutions and standardized reagents in small quantities (typically less than one gallon and generally less than one quart). These chemical solutions are all aqueous solutions.

Other activities which potentially could generate air emissions are computer (laser) printer and photocopier usage, general cleaning (using household consumer cleaning products), and repaving of the parking areas. SPC also maintains an uninterruptible power system based on gel cell and lead-acid batteries. Again, emission estimates for these operations were not performed due to the insignificant contribution of these sources on the emission estimate.

In addition to these activities, SPC operates numerous refrigeration-type air conditioning systems containing chlorofluorocarbons (CFC) which are regulated by the Title 40 Code of Federal Regulations, Part 82. These CFC-containing systems provide space cooling (for personnel and equipment) and are closed systems except when being maintained or repaired. SPC contracts with a certified contractor for the maintenance and repair of these CFC-containing units. The CFC emissions and applicability of Title 40 Code of Federal Regulations, Part 82 are not considered in this application due to the nature of these potential emissions (if any) and the fact that SPC contracts out the maintenance of these units to a maintenance organization with certified technicians.

E. Proposed Exemptions

There are no exemptions.

II. EMISSIONS INFORMATION

A. Source-wide Potential to Emit

Saguaro Power Company is a major source for NO_x, CO, and TCS (NH_3) and a non-major source for PM_{10}, SO_x, VOC, and HAP:

Table II-A-1: Source-wide PTE (tons per rolling 12-months)

Pollutant	PM_{10}	NO_x	CO	SO_x	VOC	HAP	NH_3
PTE Totals	**37.94**	**165.46**	**90.23**	**11.30**	**13.86**	**8.95**	**45.01**
Major Source Thresholds	**70**	**50/100**[2]	**70**	**70**	**50**	**25**[3]	**1.0**

[1]Total emissions are based on the worst-case scenario between natural gas combustion and fuel oil combustion in the turbines.

[2]50 tons per rolling 12-months for major source status and 100 tons per rolling 12-months for potential offset requirements.
[3]25 tons for combination of all HAPs (no single HAP exceeds 10 tons).

B. Equipment Description

The air emission source equipment and associated major equipment is listed below. In addition, common support equipment exists to support the power generation equipment.

Power Equipment

1. Two (2) GE (Frame PG 6514B) single shaft, simple cycle, nominal 35 MW combustion turbines, with:
    a. Natural gas, hydrogen gas, or fuel oil firing,
    b. Inlet air filters with filter cleaning system,
    c. Fire detection and protection system,
    d. Hydrogen cooled electric generator,
    e. Emission Units Identification A01 and A02.
2. Two (2) heat recovery steam generators (HRSG), 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. Exhaust stack, equipped with continuous emissions monitoring system (CEMS) for NO_X and CO, as well as NH_3 slip.
3. Two (2) John Zink Model LDR-11-LE, supplementary duct burners, natural gas and/or hydrogen fired, 25 MMBtu/hr maximum heat input each, Gas Skid CTG-01 (Emission Unit Identification F05 and F05a).
4. Two (2) John Zink Model LDR-11-LE, supplementary duct burners, natural gas and/or hydrogen fired, 25 MMBtu/hr maximum heat input each, Gas Skid CTG-02 (Emission Unit Identification F06 and F06a).
5. Two (2) Detroit diesel starter engines, 293 kW (445 hp) each, one engine with each turbine generator (Emission Unit Identification A03 and A04).
6. One (1) General Electric steam turbine generator, with:
    a. 3-pressure, single reheat, condensing configuration,
    b. Hydrogen cooled electric generator.

Common Support Equipment

1. One (1) No. 2 diesel fuel storage tank, fixed roof, 75,000 gallon capacity (Emission Unit Identification A08).
2. Fuel oil unloading station, manifold system for unloading trucks and railcars (Emission Unit Identification F02).
3. Fuel oil transfer pumps, two electric-driven pumps with under ground piping (Emission Unit Identification F01).
4. One (1) auxiliary Indeck/Volcano boiler, natural gas and/or hydrogen fired, 249 MMBtu/hr maximum heat input, low-NO_x burners, with FGR, SCR and oxidizing catalyst system for controlling NO_x and CO, (Emission Unit Identification A05).
    a. Exhaust stack, equipped with continuous emissions monitoring system (CEMS) for NO_X and CO, as well as NH_3 slip.
5. One (1) auxiliary Nebraska boiler, natural gas and/or hydrogen fired, 86 MMBtu/hr maximum heat input, low-NO_x burners, with FGR, (Emission Unit Identification A06).
6. One (1) ammonia storage tank, 12,000 gallons, anhydrous ammonia, sealed system (Emission Unit Identification F11).

7. Thermal-Dynamics cooling water system, a 3-cell mechanical draft unit a circulation rate of 6,395 gallons per minute per cell or 19,185 gallons per minute total (Emission Unit Identification A09a, A09b, A09c).
8. The natural gas conveyance system, compromised of a metering station, a filtering station, the CTG gas control and metering enclosures, and the HRSG duct burner control (Emission Unit Identification F03 and F04).

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. Various water storage tanks,
    d. Various chemical storage tanks,
    e. Electrical switchyard,
    f. Storage structure.

C. Emission Units and PTE

Table II-C-1: List of Emission Units

EU	Description	SCC	Type[1]
A01	GE Combustion Turbine Generator #1; M/N: PG6541B with a fired HRSG, S/N: 295525, 35 MW; 35 MEQ	20100101	TR1,MEQ
A02	GE Combustion Turbine Generator #2; M/N: PG6541B with a fired HRSG, S/N: 295524, 35 MW; 35 MEQ	20100101	TR1,MEQ
A03	Detroit Diesel Starter Engine, Model 71237300, S/N: 12VA083956, Combustion Turbine Generator #1 (445 hp)	20100102	CE2
A04	Detroit Diesel Starter Engine, Model 71237300, S/N: 12VA083901, Combustion Turbine Generator #2 (445 hp)	20100102	CE2
A05	Indeck/Volcano Auxiliary Boiler #1; 249 MMBtu/hr; M/N: 0-7-2000; S/N: N/A	31000414	F1[M]
A06	Nebraska Auxiliary Boiler #2; 86 MMBtu/hr; M/N: NOS 2A/S-55; S/N: 032-88	31000414	F1
A08	Fuel Oil Storage Tank (750,000 gallon)	40301019	T1
A09a	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 1	38500101	P1
A09b	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 2	38500101	P1[N]
A09c	Thermal-Dynamics Towers Inc., Cooling Tower; M/N: TD-3030-3-2424CF; S/N: N/A; 19,185 gpm total, 3,800 mg/L TDS, 0.0006% drift, Cell 3	38500101	P1[N]
F01	Fuel Oil Transfer Pumps	30600813	DM
F02	Fuel Oil Unloading	30600816	DM
F03	Natural Gas Metering Station	20888802	DM
F04	Natural Gas Coalescing Filters	20888802	DM
F05	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 1	20100101	DF1
F05a	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 1	20100101	DF1[N]
F06	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733, 25 MMBtu/hr, Skid # 2	20100101	DF1
F06a	John Zink Model LDR-11-LE Supplemental Duct Burner, S/N: S82733,	20100101	DF1[N]

EU	Description	SCC	Type[1]
	25 MMBtu/hr, Skid # 2		
F07	Lube Oil System – CTG-01	30600813	DM
F08	Lube Oil System – CTG-02	30600813	DM
F09	Lube Oil System – STG-03	30600813	DM
F11	Ammonia Storage and Injection, 12,000 gallons	40781699	DM

[1]Type code is an emissions unit designation for billing purposes: TR1=turbine 2.5 Megawatt or larger, MEQ=Megawatt Equivalent Fee (MWE x Fee), DM = deminimus, CE2 = stationary IC engine 351-800 hp, F1= fuel burning equipment, P1 = process equipment. Fees are listed in AQR Section 18. The M superscript means that this unit is considered to be modified for billing assessment.

Table II-C-2: Insignificant Activities

EU	Description
F10	Facility Painting

Emission calculations for the SPC not covered in this permitting action will be described in this TSD; however, some of the specific information regarding emission factors, fuel characteristics, and other site-specific information previously considered will not be presented in this document.

Turbines (EU: A01 and A02)
Potential particulate emissions for natural gas combustion in the turbines were estimated based on a manufacturer's guarantee of 2.5 pounds per hour. Operating 8,280 hours per year on this fuel will provide an annual emission rate of 10.35 tons of PM_{10} per year. The guarantee also applies to diesel fuel oil combustion, which was rated at 17 pounds of PM_{10} per hour. Operating a maximum of 480 hours per year on this fuel will provide an annual PM_{10} emission rate of 4.08 tons per year. The total maximum particulate emissions are 17 pounds per hour (using fuel oil as the worst case) and 14.43 tons per year.

Potential NO_X emissions are based on an accepted emission limit of 10 ppmvd at 15 percent oxygen for natural gas combustion and 17 ppmvd at 15 percent oxygen for fuel oil combustion. The specific "F Factor" for the fuel is unknown, but using default factors 8,740 dscf/MMBtu for natural gas and 9,920 dscf/MMBtu for fuel oil, the estimated maximum NO_x PTE would be 29.79 pounds per hour (using fuel oil as the worst case) and 75.61 tons per year. This is reasonably close to the permitted NO_x limits of 26.3 pounds per hour (using fuel oil as worst case) and 69.20 tons per year; therefore the permit will not need to be changed. The following is the methodology to convert from ppmvd to pounds per hour:

ppm / 1,000,000 * 46.01 pounds/pound-mol NO_X / MV ft^3/pound-mol gas * F dscf/MMBtu * [20.9 / (20.9 - $\%O_2$)] = pounds NO_X/MMBtu

ppm = emission limit in ppmvd
MV = molar volume of gas (default is 385 ft^3/pound-mol)
F = "F Factor" (dscf/MMBtu)
$\%O_2$ = percent oxygen at which the standard is set (whole number)

The Btu ratings for the fuels are calculated as follows:
Natural gas – 447 MMBtu/hour (design rate)
Fuel oil – 3,035 gallons/hour * 7.13 pounds/gallon * 19,289 Btu/pound / 1,000,000 Btu/MMBtu = 417.41 MMBtu/hour
Therefore:
MMBtu/hour * pounds NO_X/MMBtu = pounds/hour NO_X

Potential CO emissions are based on an accepted emission limit of 10 ppmvd at 15 percent oxygen for both natural gas and fuel oil combustion. The methodology is the same as the NO_X emission calculations. The estimated CO potential using the same default “F Factors” is 17.53 pounds per hour (using fuel oil as the worst case) and 45.87 tons per year. DAQEM has concern with the short-term emission limit, but Saguaro Power has accepted this limit and no adjustments are warranted.. The natural gas limit listed in the permit is reasonably close to the estimate, so it does not require adjustment.

Potential SO_X emissions for the natural gas combustion were calculated using a default emission factor of 0.0006 pounds/MMBtu, which were listed in the footnotes of AP-42 Table 3.1-2a.

Potential emissions from fuel oil combustion were calculated as follows:

3,035 gallons/hour * 7.13 pounds/gallon * 0.05/100 (% S) * 64 pounds/pound-mol SO_2 / 32 pounds/pound-mol S = 21.64 pounds/hour SO_2
21.64 pounds/hour * 480 hours/year / 2,000 pounds/ton = 5.19 tons/year

Because fuel oil combustion is the worst case, it is considered the short-term (pound-per-hour) limit for each combustion turbine.

VOC emissions are based on the emission factors for natural gas and fuel oil combustion from AP-42 Table 3.1-2a. Because potential VOC emissions from fuel oil are the worst case, it is considered the short-term (pound-per-hour) limit for each combustion turbine.

Ammonia emissions are based on a manufacturer’s guarantee of 4.98 pounds per hour for both natural gas and fuel oil. Assuming 8,760 hours per year of operation, the potential ammonia emissions are 21.81 tons per year.

HAP emissions for natural gas combustion are based on the emission factors from AP-42 Table 3.1-3. HAP emissions for fuel oil combustion are based on the emission factors from AP-42 Tables 3.1-4 and 3.1-5. Because the natural gas emissions are based on 8,280 hours per year and the fuel oil emissions are based on 480 hours per year, the sum total of all HAPs is considered to be the total HAP emission limit for the permit. Individual HAP delineations are provided in Attachment 1. Because potential HAP emissions from fuel oil are the worst case, it is considered the short-term (pound-per-hour) limit for each combustion turbine.

Turbine Starter Engines (EU: A03 and A04)
The two diesel-fired starter engines each have a rating of 445 horsepower. Their emissions were calculated on a Btu rating basis to provide a consistent rating number for emissions calculations instead of switching between horsepower and Btus. The Btu rating was derived as follows:

33.5 gallons/hour * 7.13 pounds/gallon * 19,289 Btu/pound = 4.61 MMBtu/hour

The particulate emission factor was taken from AP-42 Table 3.3-1. The SO_X, NO_X, CO, and VOC factors were numbers provided by the manufacturer. The HAP emission factors were taken from AP-42 Table 3.3-2. The sum total of all individual HAPs was considered to represent the total permitted HAP limit for these units.

Indeck/Volcano Boiler (EU: A05)
The emissions for this unit were calculated using manufacturer’s emission factors, except for HAP. The HAPs were calculated using the emission factors from AP-42 Table 1.4-3 and an

assumed heating value of 1,020 Btu per standard cubic foot of natural gas. The sum total of all individual HAPs was considered to be the total permitted HAP emission for this unit. The controlled emissions of 12 ppmv NO_x and 1.2 ppmv CO are achieved by low-NO_x burner with FGR and CO oxidation system.

Nebraska Boiler (EU: A06)
The emissions for this unit were calculated using manufacturer's emission factors, except for CO, SO_x and HAP. CO was determined by a performance test. The actual factor is unavailable, but available documentation suggests that the permit limit may be slightly higher than what is in the file. SO_2 was calculated using the emission factors from AP-42 Table 1.4-2 and an assumed heating value of 1,020 Btu per standard cubic foot. The HAPs were calculated using the emission factors from AP-42 Table 1.4-3 and an assumed heating value of 1,020 Btu per standard cubic foot of natural gas. The sum total of all individual HAPs was considered to be the total permitted HAP limit for this unit.

Fuel Oil Storage Tank (EU: A08)
Emissions were updated from the previous submittal and calculated using the TANKS 4.0 program for a vertical fixed roof tank using the following parameters:

1. Shell height = 40 feet
2. Diameter = 58 feet
3. Maximum liquid height = 40 feet
4. Average liquid height = 40 feet
5. Turnovers = 3.9
6. Shell color = white/white, good condition
7. Roof color = white/white, good condition
8. Roof type = dome, 4 feet high, 58 foot radius

The emissions from the storage of diesel fuel at Saguaro amount to 103.08 pounds per year of VOCs according to the program. At 8,760 hours per year, this translates into 0.01 pounds per hour and 0.05 tons per year. Based on fuel oil storage tanks elsewhere in Clark County, it can be assumed that HAPs are 0.3 percent of the VOC emissions. This translates into 3.53E-05 pounds per hour and 1.55E-04 tons per year.

Cooling Tower (EUs: A09a, A09b, and A09c)
The cooling tower emissions are calculated using the drift loss method outlined in AP 42.

Fugitive Emissions from Pipes
Emissions were estimated using the number of types of connectors and correlating them with the SOCMI Average Emission Factors from Table 2-1 of EPA-453/R-95-017, Protocol for Equipment Leak Emission Estimates. Each emission factor is provided in units of kilograms per hour per source. It is then converted to pounds per hour by multiplying the factor by 2.205 pounds per kilogram. Taking into account the type of liquid or vapor that is being carried by the connected piping, the number of each type of connector is multiplied by the emission factor to obtain leak emissions in pounds per hour and then converted to tons per year using 8,760 hours per year.

Table II-C-3: Source Potential to Emit, Including Startup and Shutdowns[1, 2]

EU	PM_{10}		NO_x		CO		SO_x		VOC		HAP		NH_3	
	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy
A01[1]	---	14.43	---	69.20	---	39.40	---	6.30	---	4.01	---	1.98	---	21.81
A01[2,3]	2.50	---	15.20	---	9.00	---	0.27	---	0.92	---	0.46	---	4.98	---
A01[2,4]	17.00	---	26.30	---	9.00	---	21.64	---	2.00	---	0.54	---	4.98	---
A02[1]	---	14.43	---	69.20	---	39.40	---	6.30	---	4.01	---	1.98	---	21.81
A02[2,3]	2.50	---	15.20	---	9.00	---	0.27	---	0.92	---	0.46	---	4.98	---
A02[2,4]	17.00	---	26.30	---	9.00	---	21.64	---	2.00	---	0.54	---	4.98	---
A03	1.43	0.09	14.38	0.90	3.75	0.23	0.92	0.06	0.41	0.03	0.03	0.01	0.00	0.00
A04	1.43	0.09	14.38	0.90	3.75	0.23	0.92	0.06	0.41	0.03	0.03	0.01	0.00	0.00
A05[5]	1.52	1.33	9.09	7.96	11.50	10.08	0.15	0.13	1.02	0.89	0.46	0.48	0.00	0.00
A05[6]	1.52	6.65	3.64	15.92	0.22	0.98	0.15	0.65	1.02	4.47	1.02	4.47	0.00	0.00
A06	0.43	1.29	3.11	9.34	3.33	9.99	0.05	0.15	0.05	1.08	0.16	0.48	0.00	0.00
A08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.05	0.01	0.01	0.00	0.00
A09a, A09b, A09c	0.22	0.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.00
F02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.00
F03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.05	0.01	0.00	0.00	0.00
F04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.01	0.00	0.00	0.00
F05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F05a	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F06a	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00	0.00
F08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00	0.00
F09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00	0.00
F11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32	1.39
Total PTE	**39.03**	**37.94**	**88.11**	**165.46**	**29.05**	**90.23**	**45.32**	**14.06**	**3.81**	**13.85**	**2.26**	**8.94**	**10.28**	**45.01**

[1] Annual emissions based on worst-case scenario of 480 hours/year of fuel oil combustion and 8,280 hours/year of natural gas combustion.
[2] Short-term emissions based on worst-case scenario between natural gas combustion and fuel oil combustion in the turbines
[3] Emissions from the combustion of natural gas in the turbine, the emissions from the duct burners are included.
[4] Emissions from the combustion of distillate oil in the turbine.
[5] Emissions from Indeck/Volcano boiler (EU: A05) prior to installation of the low-NO_x burners and CO oxidation catalyst.
[6] Emissions from Indeck/Volcano boiler (EU: A05) after installation of the low-NO_x burners and CO oxidation catalyst.

Table II-C-4: Emission Concentration Limitations in ppmvd

EU	O_2 Standard	NO_X (ppmvd)		CO (ppmvd)	
		Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
A01[1]	15%	10	17	10	10
A02[1]	15%	10	17	10	10
A05[2]	3%	30	N/A	400	N/A
A05[3]	3%	12	N/A	1.2	N/A
A06	3%	30	N/A	400	N/A

[1] Emissions from the combustion of natural gas or distillate are calculated using a four-hour rolling average not to include startup or shutdown.
[2] Emission concentration limits for Indeck/Volcano boiler (EU: A05).
[3] Emission concentration limits for Indeck/Volcano boiler (EU: A05) after completion of the boiler modification.

Table II-C-5: Startup and Shutdown Emissions per Emission Unit (pounds/hour) [4]

EU	PM_{10}	NO_X	CO	SO_x	VOC	HAP	NH_3
A01[1,3]	2.5	65.00	9.00	0.27	0.94	0.46	2.04
A02[1,3]	2.5	65.00	9.00	0.27	0.94	0.46	2.04
A01[2,3]	17.00	104.00	9.00	21.64	0.17	0.54	2.04
A02[2,3]	17.00	104.00	9.00	21.64	0.17	0.54	2.04
A05	1.87	9.11	9.24	0.15	1.34	0.47	---

[1]Emissions from the combustion of natural gas in the turbine.
[2]Emissions from the combustion of distillate oil in the turbine.
[3]Startup has a duration of one hour.
[4]Start-up and shut-down emission rates are to be used to calculate compliance with annual emissions limits. Emission factors will be used when CEMS data is not available.

Table II-C-6: Source Allowable Emissions[1]

Pollutant	PM_{10}	NO_x	CO	SO_x	VOC	HAP	NH_3
lbs/hour	**39.03**	**88.11**	**29.05**	**45.32**	**3.81**	**2.26**	**10.28**
tons/year	**37.94**	**165.46**	**90.23**	**11.30**	**13.86**	**8.95**	**45.01**

1Total emissions are based on the worst-case scenario between natural gas combustion and fuel oil combustion in the turbines.

D. Testing

Performance testing is subject to 40 CFR 60 Subpart A; 40 CFR 60 Subpart GG; 40 CFR 60 Subpart Db; 40 CFR 60 Subpart Dc; DAQEM Guideline on Performance Testing and Section 49 of the Air Quality Regulations. Initial performance testing for the turbines was completed on May 14, 2002. Any additional required testing will be performed using the following methods:

Table II-D-1: Performance Testing Requirements (40 CFR 60, Appendix A)

Test Point	Pollutant	Method
Turbine Exhaust Stack	NO_X	Chemiluminescence Analyzer (EPA Method 7E)
Turbine Exhaust Stack	CO	EPA Method 10 analyzer
Turbine Exhaust Stack	VOC	EPA Method 25a
Turbine Exhaust Stack	NH_3 Slip	Method Preapproved by DAQEM/EPA
Turbine Exhaust Stack	PM_{10}	EPA Method 5 or 5A
Turbine Exhaust Stack	Opacity	EPA Method 9
Boiler Exhaust Stack	NO_X	Chemiluminescence Analyzer (EPA Method 7E)
Boiler Exhaust Stack	CO	EPA Method 10 analyzer
Stack Gas Parameters	---	EPA Methods 1, 2, 3, 4

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

The amended OP issued in October 2002 includes performance testing requirements. Performance testing for turbine operation using natural gas shall be conducted annually and within 60 days of the anniversary date of the previous performance test. The performance testing is subject to DAQEM's "Guideline on Performance Testing" (Revised 09/05/03).

The performance testing for turbine operation using diesel fuel shall be conducted only prior to diesel fuel combustion. The source is permitted to operate each turbine unit (EU: A01 and A02) while combusting low sulfur diesel fuel (<0.05 percent sulfur by weight), only when all performance testing requirements are met. Combusting diesel fuel allows for continuous operation while the natural gas supply is disturbed. However, in practice the source was never required to use diesel fuel for regular operation, but conducted performance tests as scheduled. The tests required refitting of the equipment for diesel combustion and resulted in increased emissions of pollutants.

E. Continuous Emissions Monitoring

The pollutant-specific emission units at the facility are two GE natural gas-fired combined-cycle combustion turbine/generators, each equipped with low-NO_X burners (EUs: A01 and A02). These units are permitted to fire on hydrogen gas, natural gas and fuel No. 2 distillate oil. The exhaust gases will exit to the atmosphere after leaving the turbine, having already passed through an oxidation catalyst for CO control and selective catalytic reduction (SCR) system for NO_X control. There are also two auxiliary boilers that are used to provide continuous steam supply (EUs: A05 and A06).

According to EPA AP-42, Section 3.1.3.1, NO_x emissions are strongly dependent on the high temperatures developed in the combustor. The NO_x is formed by three different mechanisms. Thermal NO_x is formed during thermal dissociation and subsequent reaction of N_2 and O_2 molecules in the combustion air. Most thermal NO_x is formed in the high temperature stoichiometric flame pockets downstream of the fuel injections where combustion air has mixed sufficiently with the fuel to produce peak temperature at fuel/air interface. Prompt NO_x, which is formed from early reactions of N_2 molecules, is usually negligible when compared to the amount of thermal NO_x formed. The third mechanism, fuel NO_x, is negligible when natural gas is burned. Consequently, during natural gas combustion essentially all NO_x formed is thermal NO_x. Maximum reduction of thermal NO_x can be achieved by control of temperature, for given stoichiometry.

To demonstrate continuous direct compliance with all emission limitations for NO_X and CO specified in this permit, the source operates continuous emission monitoring system (CEMS) for NO_X, CO and O_2 on each turbine (EU: A01 and A02) and Indeck/Volcano boiler unit (EU: A05) in accordance with 40 CFR 60. Each CEMS includes an automated data acquisition and handling system. Each system shall monitor and record at least the following data:

a. exhaust gas concentration of NO_X, CO and diluent $O_{2;}$
b. exhaust gas flow rate (by direct or indirect methods);
c. fuel flow rate,
d. hours of operation;

e. four-hour rolling averages for each of NO_X and CO concentration (EUs: A01 and A02),
f. three-hour rolling averages for each of NO_X and CO (EU: A05);
g. hourly , daily and quarterly accumulated mass emissions of NO_X, CO and NH_3;
h. hours of downtime of the CEMS.

Each CEMS shall be installed, calibrated, operational, and certified prior to issuance of an operating permit. A quality assurance plan for all CEMS includes auditing schedules, reporting schedules, design specifications, and other quality assurance requirements for the each CEMS. Required periodic audit procedures and QA/QC procedures for CEMS shall conform to the provisions of 40 CFR 60 Subpart B, Appendix F. Relative accuracy test audits (RATA) of the CO, NO_X and O_2 CEMS shall be conducted at least annually. The facility shall install a fuel flow meter for each combined cycle turbine, each duct burner, and the auxiliary Indeck/Volcano boiler, and shall monitor the natural gas fuel flow rate of each emission unit with CEMS. The primary method for demonstrating compliance with this requirement is demonstrated by a Data Acquisition System (DAS).

SPC must also operate an ammonia predictive emissions monitoring system (PEMS) on each combined cycle emission unit stack. The ammonia PEMS is based on the principle that NO_X reduction occurs at a 1:1 molar ratio with ammonia. Typically though, more ammonia is injected than is "theoretically" needed because the physical process doesn't allow for ideal conditions like complete mixing, uniform ammonia flow, gas flow, temperature distributions, etc. The un-reacted ammonia slips through the catalyst bed and out of the stack as ammonia emissions.

The PEMS uses two (2) NO_X readings, an ammonia flow reading and several constants to calculate an estimate of ammonia emissions. One (1) NO_X reading is from an analyzer at the SCR inlet, and the other is from the stack CEMS analyzer. These measure the change in NO_X across the SCR (always a reduction), which is converted to an ideal ammonia usage based on the stoichiometric principle noted above. This is then subtracted, on a molar basis, from actual ammonia usage and converted to an ammonia concentration going out of the stack. The calculation is carried out in the CEMS and stored in the computer that stores the CEMS parameters.

III. REGULATORY REVIEW

A. Local Regulatory Requirements

DAQEM 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); including Part 70 and others;
3. Nevada Revised Statutes (NRS), Chapter 445; Sections 401 through 601;
4. Portions of the AQR 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 DAQEM 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.

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 DAQEM 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. These regulations may be accessed on the Internet at: http://www.co.clark.nv. us/air_quality/Regs.htm

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 III-A-1: AQR Section 12 and 55 Summary Table

	PM_{10}	**NO_X**	**CO**	**SO_X**	**VOC**	**HAP**
Source PTE (tpy)	**37.94**	**165.46**	**90.23**	**11.30**	**13.86**	**8.95**
Nonmajor Source	< 70 tpy	< 50 tpy	< 70 tpy	≤ 100 tpy	< 50 tpy	≤ 25 tpy
Control Technology	BACT	BACT	BACT	BACT	BACT	BACT
Notice of Proposed Action	If NEI ≥ 15 tpy	If NEI ≥ 20 tpy	If NEI ≥ 10 tpy	If NEI ≥ 40 tpy	If NEI ≥ 20 tpy	If PTE or NEI ≥ 10 tpy
Preconstruction Ambient Air Monitoring	If NEI ≥ 25 tpy	If NEI ≥ 40 tpy	No	If NEI ≥ 40 tpy	No	No
Postconstruction Ambient Air Monitoring	If NEI ≥ 25 tpy	If NEI ≥ 40 tpy	No	If NEI ≥ 40 tpy	No	No
Additional Impact Analysis	If NEI ≥ 25 tpy	If NEI ≥ 40 tpy	No	If NEI ≥ 40 tpy	No	No

Discussion: SPC is a major source of NO_X, CO, and NH_3. As part of the original New Source Review Analysis all of these emissions triggered notice of proposed action.

Table III-A-2: Clark County DAQEM – Air Quality and State Implementation Plan with Facility Compliance or Requirement

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
0. Definitions	applicable definitions	yes	entire source
1. Definitions	applicable definitions – “Affected Facility”, “Air Contaminant”, “Air Pollution Control Committee”, “Area Source”, “Atmosphere”, “Board”, “Commercial Off-Road Vehicle Racing”, “Dust”, “Existing Facility”, “Existing Gasoline Station”, “Fixed Capital Cost”, “Fumes”, “Health District”, “Hearing Board”, “Integrated Sampling”, “Minor Source”, “Mist”, “New Gasoline Station”, “New Source”, “NIC”, “Point Source”, “Shutdown”, “Significant”, “Single Source”, “Smoke”, “Source of Air Contaminant”, “Special Mobile Equipment”, “Standard Commercial Equipment”, “Standard Conditions”, “Start Up”, “Stop Order”, “Uncombined Water”, and “Vapor Disposal System”	yes	entire source
2. Air Pollution Control Board	all subsections	yes	entire source
4. Control Officer	all subsections	yes	entire source
5. Interference with Control Officer	all subsections	yes	entire source
6. Injunctive Relief	all subsections	yes	entire source
8. Persons Liable for Penalties - Punishment: Defense	all subsections	yes	entire source
9. Civil Penalties	all subsections	yes	entire source
10. Compliance Schedule	when applicable; applicable subsections	yes	entire source
11. Ambient Air Quality Standards	applicable subsections	yes	entire source
12. Preconstruction Review for New or Modified Stationary Sources	All subsections except the following: § 12.2.18 HAP Sources in Clark County. § 12.2.20 Additional Requirements for STATIONARY SOURCES with Beryllium, Mercury, Vinyl Chloride, or Asbestos EMISSIONS in Clark County	yes	The turbine was installed and permitted before Section 12 applicability. There were no reported turbine modifications with emissions increases since installation. Section 12 applies to diesel-powered standby generator. The Part 70 OP requires NPC to comply with all applicable requirements with respect to new or modified emission units.
13. Emission Standards for Hazardous Pollutants	Condition A-37 is the EPA-required standard condition concerning asbestos.	no	entire source

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
14. New Source Performance Standards	CCAQR Section 14.1.56: Subpart GG Standards of Performance for Gas Turbines CCAQR Section 14.1.14: Subpart Db Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units CCAQR Section 14.1.15: Subpart Dc - Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units CCAQR Section 14.1.26: Subpart Kb - Standards of Performance for Storage Vessels for Petroleum Liquids	no	Turbines, Indeck/Volcano Boiler, Nebraska Boiler, Fuel Storage Tank
16. Operating Permits	all subsections	yes	entire source
17. Dust Control Permit and Construction Activities	all subsections	yes	entire source
18. Permit and Technical Service Fees	§ 18.1 Operating Permit Fees § 18.2 Annual Emission Unit Fees § 18.4 New Source Review Application Review Fee § 18.5 Part 70 Application Review Fee § 18.6 Annual Part 70 Emission Fee § 18.14 Billing Procedures	yes	entire source
19. Part 70 Operating Permit Federal Approval (11/25/01)	§ 19.2 Applicability § 19.3 Part 70 Permit Applications § 19.4 Part 70 Permit Content § 19.5 Permit Issuance, Renewal, Re-openings, and Revisions § 19.6 Permit Renewal by the EPA and Affected States § 19.7 Fee Determination and Certification	N/A	entire source
20. Emission Standards for Hazardous Air Pollutants for Source Categories	all subsections	yes	No emission unit is subject to a federal MACT standard.
21. Acid Rain Permits	all subsections	yes	An acid rain permit is not required.
22. Acid Rain Continuous Emissions Monitoring	all subsections	yes	An acid rain permit is not required.
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	yes	entire source
25.1 Upset/Breakdown, Malfunctions	§ 25.1 Requirements for the excess emissions caused by upset/breakdown and malfunctions	no	entire source
25.2 Upset/Breakdown, Malfunctions	§ 25.2 Reporting and Consultation	yes	entire source
26. Emission of Visible Air Contaminants	§ 26.1 Limit on opacity (≤ 20 percent for 3 minutes in a 60-minute period)	yes	entire source

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
28. Fuel Burning Equipment	Emission Limitations for PM	yes	entire source
29. Sulfur Contents of Fuel Oil	Sulfur content shall be equal to or less than 0.05 percent sulfur by weight	no	Turbines, Starter Engines
35. Diesel Engine Powered Electrical Generating Equipment	all subsections	yes	The Part 70 permit limits use of the emergency generator to testing, maintenance, and emergencies, and prohibits its use for dispatchable peak shaving.
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
55. Preconstruction Review for New or Modified Stationary Sources in the 8-hour Ozone Nonattainment Area	all subsections	no	entire source
60. Evaporation and Leakage	all subsections	yes	entire source
70. Emergency Procedures	all subsections	yes	entire source
80. Circumvention	all subsections	yes	entire source
81. Provisions of Regulations Severable	all subsections	yes	entire source
90. Fugitive Dust from Open Areas and Vacant Lots	all subsections	no	entire source
91. Fugitive Dust from Unpaved Roads, Unpaved Alleys, and Unpaved Easement Roads	all subsections	no	entire source
92. Fugitive Dust from Unpaved Parking Lots	all subsections	no	entire source

AQR SECTION 11 - AMBIENT AIR QUALITY STANDARDS [Amended 07/01/04] *(in part)*

Discussion: Saguaro Power Company is a major source located in Hydrographic Area (HA) 212 (Las Vegas Valley). The source consists of two turbine generators, two starter engines, two boilers, one cooling tower and other equipment. Minor source baseline dates for NO_X (October 21, 1988) and SO_2 (June 29, 1979) have been triggered in HA 212.

DAQEM modeled the source using AERMOD to track the Prevention of Significant Deterioration (PSD) increment consumption. 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) 7.5-minute Digital Elevation Model (DEM) terrain data was used to calculate elevations. Table 1 presents the results of the modeling.

Table III-A-3: PSD Increment Consumption

Pollutant	Averaging Period	PSD Increment Consumption by the Source ($\mu g/m^3$)	Location of Maximum Impact	
			UTM X (m)	UTM Y (m)
SO_2	3-hour	51.54[1]	679215	3990313
SO_2	24-hour	30.15[1]	679215	3990313
SO_2	Annual	0.20	679215	3990313
NO_x	Annual	5.14	679215	3990313

[1]Modeled 2nd High Concentration

Table III-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 PART 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 DAQEM 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 OP. DAQEM requires records to be maintained for five years, a more stringent requirement than the two (2) years required by § 60.7.

40 CFR § 60.8 - Performance tests.

Discussion: These requirements are found in the Part 70 OP. 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. DAQEM requirements for initial performance testing are identical to § 60.8. DAQEM 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. Section 26 of the AQR is more stringent than the federal opacity standards, setting a maximum of 20 percent obscurity except for three (3) minutes in any 60-minute period. SPC shall operate in a manner consistent with this section of the regulation.

40 CFR § 60.12 – Circumvention.

Discussion: This prohibition is addressed in the Part 70 OP. This is also local rule § 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. 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 two (2) turbines at this source.

40 CFR § 60.332 - Standard for nitrogen oxides.

Discussion: See Table IV-C-1.

40 CFR § 60.333 - Standard for sulfur dioxide.

Discussion: See Table IV-C-1. The sole use of pipeline-quality natural gas with total sulfur content less than 0.8 percent (8000 ppmw) satisfies this requirement.

40 CFR § 60.334 - Monitoring of operations.

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

40 CFR § 60.335 - Test methods and procedures.

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

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

40 CFR § 60.40b – Applicability and delegation of authority.

Discussion: The auxiliary Volcano boiler (EU: A05) is subject to the provisions of this subpart. It has a rated capacity of 249 MMBtu per hour.

40 CFR § 60.42b – Standard for sulfur dioxide (SO_2).

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

40 CFR § 60.43b – Standard for particulate matter (PM).

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

40 CFR § 60.44b – Standard for nitrogen oxides (NO_X).

Discussion: See Table IV-C-1.

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 Nebraska boiler (EU: A06) is rated 86 MMBtu per hour; therefore, Subpart Dc is applicable to this emission unit.

40 CFR § 60.42c – Standard for sulfur dioxide (SO_2).

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

40 CFR § 60.43c – Standard for particulate matter (PM).

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 the Part 70 operating permit.

Subpart Kb - Standards of Performance for Organic Volatile Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

40 CFR § 60.110b – Applicability and designation of affected facility,

Discussion: The fuel storage tank (EU: A08) is not a subject to the provisions of this subpart because a storage vessel capacity is greater than 151 cubic meters (m^3) and the maximum true vapor pressure of the stored liquid is less than 3.5 kilopascals (kPa).

Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

40 CFR § 60.4305 – Applicability.

Discussion: The two (2) turbines (EUs: A01 and A02) are not subject to the provisions of this subpart because these turbines commenced construction, modification, or reconstruction before February 18, 2005.

40 CFR PART 64 - COMPLIANCE ASSURANCE MONITORING

40 CFR § 64.2 – Applicability.

Discussion: The CAM Rule is not applicable to the auxiliary boilers (EUs: A05 and A06), the starter engines (EUs: A03 and A04), or the fuel oil storage (EU: A08) 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 compliance. The CAM Rule is not applicable to these units for SO_X based on the applicability statement outlined in 40 CFR 64.2(a) (2). 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 and A02) are also not CAM-applicable for VOC emissions based on the exemption outlined in 40 CFR 64.2(a) (3), i.e., the potential pre-control emissions are less than the major threshold.

40 CFR PART 72 - ACID RAIN PERMITS REGULATION

Subpart A – Acid Rain Program General Provisions

40 CFR § 72.6 – Applicability.

Discussion: SPC is the cogeneration facility exempted based on the applicability criteria defined in Part 72.6 (b)(4); therefore, the provisions of this regulation do not apply.

40 CFR PART 73 – ACID RAIN SULFUR DIOXIDE ALLOWANCE SYSTEM

Discussion: SPC is not a subject of 40 CFR Part 72; therefore, the provisions of this regulation do not apply.

40 CFR PART 75 - CONTINUOUS EMISSION MONITORING

Discussion: SPC is not subject to the Acid Rain emission limitations of 40 CFR Part 72; therefore, the facility is not subject to the monitoring requirements of this regulation.

IV. COMPLIANCE

A. Compliance Certification

19.3.3.9 Requirements for compliance certification:

(a) Regardless of the date of issuance of this Part 70 OP, the schedule for the submittal of reports to the DAQEM Compliance Reporting Supervisor shall be as follows:

Table IV-A-1: Reporting Schedule

Quarter	Applicable Period	Due Date	Required Contents
1	January, February, March	April 30 each year	Quarterly Report for 1st Calendar Quarter
2	April, May, June	July 30 each year	Quarterly Report for 2nd Calendar Quarter
3	July, August, September	October 30 each year	Quarterly Report for 3rd Calendar Quarter
4	October, November, December	January 30 each year	Quarterly Report for 4th Calendar Quarter

Quarter	Applicable Period	Due Date	Required Contents
4	Calendar Year	January 30 Each year	Annual Compliance Certification Report

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

(b) A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods.
(c) A schedule for submission of compliance certifications during the permit term.
(d) A statement indicating the source's compliance status with any applicable enhanced monitoring and compliance certification requirements of the Act.

B. Compliance Summary

Table IV-B-1: Compliance Summary Table - AQR

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 0 [amended 10/7/04]	Definitions.	Applicable – SPC will comply with all applicable definitions as they apply.	SPC will meet all applicable test methods should new definitions apply.	SPC complies with applicable requirements.
CCAQR Section 4 [amended 7/1/04]	Control Officer.	Applicable – The Control Officer or his representative may enter into SPC property, with or without prior notice, at any reasonable time for purpose of establishing compliance.	SPC will allow Control Officer to enter Station property as required.	SPC complies with applicable requirements.
CCAQR Section 11 [amended 7/1/04]	Ambient Air Quality Standards.	Applicable – SPC is a source of air pollutants.	SPC demonstrated compliance in the ATC permit application with air dispersion modeling.	SPC complies with applicable requirements.
CCAQR Section 12.1 [amended 10/7/04]	General application requirements for construction of new and modified sources of air pollution.	Applicable – SPC applied for and the ATC permit was issued before commencing construction.	SPC received the ATC permit to construct.	SPC complies with applicable requirements.
CCAQR Section 12.2.2 [amended 10/7/04]	Requirements for specific air pollutants: PM_{10} emission source located in the Serious Non-Attainment Area.	Applicable – SPC has PM_{10} PTE < 70 TPY.	All new or modified emission units at the SPC will meet LAER requirement.	SPC complies with applicable requirements.
CCAQR Section 12.2.7 [amended 10/7/04]	Requirements for specific air pollutants: CO sources located in the Serious Non-Attainment Area.	Applicable – SPC has CO PTE > 70 TPY.	All new or modified emission units at the SPC will meet LAER requirement.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 12.2.12 [amended 10/7/04]	Requirements for specific air pollutants: VOC sources located in the VOC Management Area.	Not Applicable – SPC is located in Hydrographic Area 212.	Not Applicable.	Not Applicable.
CCAQR Section 12.2.14 [amended 10/7/04]	Requirements for specific air pollutants: NO_X sources located in the NO_X Management Area.	Applicable – SPC has NO_X PTE > 50 TPY.	All new or modified emission units at the SPC will meet BACT requirement.	SPC complies with applicable requirements.
CCAQR Section 12.2.16 [amended 10/7/04]	Requirements for specific air pollutants: SO_2 sources located in the PSD area.	Applicable – SPC has SO_2 PTE > 40 TPY.	All new or modified emission units at the SPC will meet BACT requirement.	SPC complies with applicable requirements. Sulfur content of natural gas will not exceed 0.75 grains per 100 dscf (based on 12-month rolling average).
CCAQR Section 12.2.19 [amended 10/7/04]	Requirements for specific air pollutants: TCS sources in Clark County	Applicable – SPC does have ammonia (NH_3) emissions at 45.01 TPY and NH_3 is a locally regulated TCS. The BACT requirement for NH_3 is 10 ppm or less for ammonia slip, and acceptable monitoring.	The BACT requirement for NH_3 is 10 ppm or less NH_3 slip, and acceptable monitoring. The CTGs/HRSGs meet BACT requirements based on meeting the 10-ppm NH_3 slip limit with PEMS monitoring.	SPC complies with applicable requirements.
CCAQR Section 12.5 [amended 10/7/04]	Air Quality Models	Applicable – Dispersion modeling will be performed as required for any future major modifications.	As applicable, future dispersion modeling will be performed in ATC permit modifications will be in accordance with provisions of 40 CFR Part 51, Appendix W.	SPC complies with applicable requirements.
CCAQR Section 12.7 [amended 10/7/04]	Continuous Emission Monitoring (CEM) Systems	Applicable – SPC has NO_X and CO PTE > 100 TPY. NO_X and CO CEMS installed on all stacks and meets provisions of 40 CFR Parts 60 and 75.	Station submitted all required protocols/test plans per ATC permit prior to CEMS certification. CEMS certification was approved by DAQEM.	Station complies with applicable requirements.
CCAQR Section 14.1.1 Subpart A [amended 7/1/04]	New Source Performance Standards (NSPS) General Provisions	Applicable – SPC is an affected facility under the regulations. Section 14 is locally enforceable; however, the NSPS standards referenced are federally enforceable.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 14.1.14 Subpart Db [amended 7/1/04]	New Source Performance Standards – Standards of Performance for Industrial - Commercial – Institutional Steam Generating Units	Applicable – SPC has the natural gas-fired steam generating unit with heat input greater than 100 MMBtu/hr.	The Volcano boiler meets the applicable NO_X emission standard. NO_X emissions determined by EPA Method 7E.	SPC complies with applicable requirements.
CCAQR Section 14.1.15 Subpart Dc [amended 7/1/04]	New Source Performance Standards – Standards of Performance for Small Industrial - Commercial – Institutional Steam Generating Units	Applicable – SPC has the natural gas-fired steam generating unit with heat input less than 100 MMBtu/hr, but greater than 10 MMBtu/hr.	The Nebraska boiler meets the applicable NO_X emission standard. NO_X emissions determined by EPA Method 7E.	SPC complies with applicable requirements.
CCAQR Section 14.1.56 Subpart GG [amended 7/1/04]	Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines	Applicable – The two (2) SPC turbines are natural gas-fired units with heat input greater than 10 MMBtu/hr.	The two (2) turbines meet the applicable NO_X emission standard. NO_X emissions determined by EPA Method 7E.	SPC complies with applicable requirements.
CCAQR Section 16 [amended 7/1/04]	DAQEM Operating Permits	Applicable – Any emission unit of stationary source must apply for and obtain a DAQEM operating permit Station applied for the operating permit from DAQEM.	SPC applied for and received operating permit from DAQEM prior to commercial operation.	SPC complies with applicable requirements.
CCAQR Section 17 [amended 7/1/04]	Dust Control Permit for Construction Activities Including Surface Grading and Trenching	Applicable – SPC will need to apply for dust control permit in event construction activity greater than ¼ acre (aggregate) or trench at least 100 ft in length (and aggregate acreage greater than ¼ acre).	SPC applied for permits as needed during initial construction and conformed to required best management practices in dust control permit. Station will continue to do so in future as needed.	SPC complies with applicable requirements.
CCAQR Section 18 [amended 1/20/05]	Permit and Technical Service Fees	Applicable – SPC will be required to pay all required/applicable permit and technical service fees.	SPC is required to pay all required/applicable permit and technical service fees.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 19 [amended 7/1/04]	40 CFR Part 70 Operating Permits	Applicable – SPC is a major stationary source and under Part 70 the initial Title V permit application was submitted as required. Renewal applications are due between 6 and 18 months prior to expiration. Revision applications will be submitted within 12 months or commencing operation of any new emission unit. Section 19 is both federally and locally enforceable	SPC reviewed the initial Part 70 permit dated January 15, 2003. This renewal application was submitted before June 15, 2007. Applications for new units will be submitted within 12 months of startup.	SPC complies with applicable requirements.
CCAQR Section 21 [amended 7/1/04]	Acid Rain Permits	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 72.6 (b)(5).	Not Applicable.	Not Applicable.
CCAQR Section 22 [amended 7/1/04]	Acid Rain Continuous Emission Monitoring	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 75.2 (b)(2).	Not Applicable.	Not Applicable.
CCAQR Section 25 [amended 7/1/04]	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 one (1) hour of onset of such event.	SPC complies with applicable requirements.
CCAQR Section 26 [amended 7/1/04]	Emissions of Visible Air Contaminants	Applicable – Opacity for the SPC combustion turbine must not exceed 20 percent for more than three (3) minutes in any 60-minute period.	Compliance determined by EPA Method 9	SPC complies with applicable requirements.
CCAQR Section 27 [amended 7/1/04]	Particulate Matter from Process Weight Rate	Applicable – SPC 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.	SPC complies with applicable requirements.
CCAQR Section 28 [amended 7/1/04]	Fuel Burning Equipment	Applicable – The PM emission rate for the combustion the turbines and boilers is well below those established based on Section 28 requirements.	Maximum allowable PM emission rate determined from equation in Section 28.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 29 [amended 7/1/04]	Sulfur Content of Fuel Oil	Applicable – The diesel fuel that will be burned in the emergency generator engine at the SPC will require low sulfur fuel with sulfur content less than 0.05 percent by weight. Section 29 is locally enforceable only.	Fuel sulfur content verification obtained from fuel oil supplier.	SPC complies with applicable requirements.
CCAQR Section 40 [amended 7/1/04]	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.	SPC air contaminant emissions controlled by pollution control devices or good combustion in order not to cause a nuisance.	SPC complies with applicable requirements.
CCAQR Section 41 [amended 7/1/04]	Fugitive Dust	Applicable – SPC shall take necessary actions to abate fugitive dust from becoming airborne.	Station utilizes appropriate best practices to not allow airborne fugitive dust.	SPC complies with applicable requirements.
CCAQR Section 42 [amended 7/1/04]	Open Burning	Applicable – In event SPC 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.	SPC will contact the DAQEM and obtain approval in advance for applicable burning activities as identified in the rule.	SPC complies with applicable requirements.
CCAQR Section 43 [amended 7/1/04]	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.	SPC will not operate its facility in a manner which will cause odors. SPC is a natural gas fired facility and is not expected to cause odors.	SPC complies with applicable requirements.
CCAQR Section 49 [amended 12/02/05]	Emission Standards for Boilers and Steam Generators Burning Fossil Fuels	Applicable – The SPC auxiliary boilers are subject to performance testing and burner efficiency testing requirements. The heat recovery steam generators (HRSG) are exempt under Section 49.3.2.	SPC submitted required test protocols prior to initial performance testing. Tests reported within 60 days. DAQEM approves test reports.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
CCAQR Section 55 [adopted 12/21/04]	Preconstruction review for New or Modified Stationary Sources in the 8-Hour Ozone Nonattainment Area	Applicable – SPC is located in Las Vegas Valley airshed (hydrographic area 212) and will need to meet the applicable emission control requirements at times of future modifications.	In the event Station undertakes a major modification, the facility will have to apply BACT and LAER control requirements.	SPC complies with applicable requirements.
CCAQR Section 70.4 [amended 7/1/04]	Emergency Procedures	Applicable – SPC submitted an emergency standby plan for reducing or eliminating air pollutant emissions in the Section 16 Operating Permit Application.	SPC submitted an emergency standby plan and received the Section 16 Operating Permit.	SPC complies with applicable requirements.

Table IV-B-2: Compliance Summary Table – Federal Regulations

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR Part 52.21	Prevention of Significant Deterioration (PSD)	Applicable – SPC PTE > 100 TPY and is listed as one of the 28 source categories.	BACT analysis, air quality analysis using modeling, and visibility and additional impact analysis performed for original ATC permits.	SPC complies with applicable sections as required by PSD regulations.
40 CFR Part 52.1470	SIP Rules	Applicable – SPC is classified as a Title V source, and SIP rules apply.	Applicable monitoring and record keeping of emissions data.	SPC is in compliance with applicable state SIP requirements including monitoring and record keeping of emissions data.
40 CFR Part 60, Subpart A	Standards of Performance for New Stationary Sources (NSPS) – General Provisions	Applicable – SPC is an affected facility under the regulations.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.
40 CFR Part 60, Subpart Db	Standards of Performance for New Stationary Sources (NSPS) – Industrial-Commercial-Institutional Steam Generating Units	Applicable – SPC has emission units that are subject to the requirements of this subpart.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.
40 CFR Part 60, Subpart Dc	Standards of Performance for New Stationary Sources (NSPS) – Small Industrial-Commercial-Institutional Steam Generating Units	Applicable – SPC has emission units that are subject to the requirements of this subpart.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.
40 CFR Part 60, Subpart GG	Standards of Performance for New Stationary Sources (NSPS) – Stationary Gas Turbines	Applicable – The SPC two turbines are natural gas-fired units with heat input greater than 10 MMBtu/hr.	Applicable monitoring, recordkeeping and reporting requirements.	SPC complies with applicable requirements.

Citation	Title	Applicability	Applicable Test Method	Compliance Status
40 CFR Part 60	Appendix A, Method 9 or equivalent, (Opacity)	Applicable – Emissions from stacks are subject to opacity standards.	Opacity determined by EPA Method 9.	SPC complies with applicable requirements.
40 CFR Part 63	Emission Standards for Hazardous Air Pollutants	Not Applicable – SPC has a total HAPs limit less than an aggregate total of 25 TPY. No single HAP is greater than 10 TPY.	Not Applicable.	Not Applicable.
40 CFR Part 64	Compliance Assurance Monitoring	Not Applicable – SPC have CEMS to monitor NO_x and CO emissions, the NH_3 emissions are continuously monitored with PEMS. SPC is exempt from CAM regulations based on 40 CFR 64.2 (b)(1)(Vi).	SPC continuously monitors NO_x and CO missions with CEMS. NH_3 emissions are monitored with PEMS.	SPC complies with applicable requirements.
40 CFR Part 68	Chemical Accident Prevention Provisions	Applicable – SPC stores and handles anhydrous ammonia (NH_3).	Construction approval and a Risk Management Plan (RMP) were required for the Nevada Department of Environmental Protection for storage and use of NH_3. SPC adheres to SPC management programs.	SPC complies with applicable requirements.
40 CFR Part 70	Federally Mandated Operating Permits	Applicable – SPC is a major stationary source and under Part 70 the initial Title V permit application was submitted as required. Renewal applications are due between 6 and 18 months prior to expiration. Revision applications will be submitted within 12 months or commencing operation of any new emission unit.	SPC reviewed the initial Part 70 permit dated February 29, 2000. The renewal application was submitted on June 18, 2003. Applications for new units will be submitted within 12 months of startup.	SPC complies with applicable requirements.
40 CFR Part 72	Acid Rain Permits Regulation	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 72.6 (b)(4).	Not Applicable.	Not Applicable.
40 CFR Part 73	Acid Rain Sulfur Dioxide Allowance System	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 73.2 (a).	Not Applicable.	Not Applicable.
40 CFR Part 75	Acid Rain CEMS	Not Applicable – SPC is exempt from acid rain regulations based on 40 CFR 75.2 (b)(2).	Not Applicable.	Not Applicable.
40 CFR Part 82	Protection of Stratospheric Ozone	Applicable – SPC is subject to stratospheric ozone regulations based on 40 CFR 82.4.	Applicable.	Applicable.

C. 40 CFR Subparts Db, Dc and GG Streamlining Demonstration for Shielding Purposes

Table IV-C-1: Streamlining Demonstration

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 [(1)]	10.0 ppmvd NO_X @ 15% O_2 (natural gas)	N/A	75 [(1)]	10.0	Yes	4 hour	4 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.
60.332 (GG)	75 ppmvd NO_X @ 15% O_2 [(1)]	17.0 ppmvd NO_X @ 15% O_2 (fuel oil)	N/A	75 [(1)]	17.0	Yes	4 hour	4 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)	150 ppmvd (326 lbs/hr) SO_X @ 15% O_2 [(1)]	0.27 lb/hr SO_X @ 15% O_2 (natural gas)	N/A	326	0.27	Yes	4 hour	4 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% of S by weight (fuel oil)	0.05% of S by weight (fuel oil)	N/A	0.8	0.05	Yes	N/A	N/A	N/A	The permit limit is more stringent than the standard, based upon both concentration.

			Value Comparison				Averaging Period Comparison			
Regulation (40 CFR)	Regulatory Standard	Permit Limit	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?	Streamlining Statement for Shielding Purposes
										Compliance with the permit demonstrates compliance with the standard.
60.43b (Db)	20% Opacity	20% Opacity	N/A	20	20	Yes	60-minute period, excepting 6 minutes	60-minute period, excepting 3 minutes	Yes	The permit limit is more stringent than the standard, based upon averaging time/duration allowed. Compliance with the permit demonstrates compliance with the standard.
60.44b (Db)	0.20 lb NO_X per MMBtu (192 ppm @ 15% O_2)	12.0 ppm NO_X @ 15% O_2	N/A	192.0	12.0	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.
60.42c (Dc)	SO_2 Standards Not Applicable for Natural Gas	0.05 lbs/hr, Natural Gas	N/A	N/A	0.05 lbs/hr	Yes	N/A	N/A	N/A	Federal standard is not applicable for Natural Gas. The permit limit is more stringent
60.43c (Dc)	PM Standards Not Applicable for Natural Gas	0.43 lbs/hr, Natural Gas	N/A	N/A	0.43 lbs/hr	Yes	N/A	N/A	N/A	Federal standard is not applicable for Natural Gas. The permit limit is more stringent

[1] 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: $EF = Cd * Cf * Fd * 20.9 / (20.9 - \%O_2)$ and $E = EF * HI$
where:

EF = emission rate (lb/MMBtu);
Cd = emission concentration (ppmvd);
Cf for NO_X = 1.194E-07 (lb NO_X/dscf ppm);
Fd = 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).

D. Summary of Monitoring for Compliance

Table IV-D-1: Compliance Monitoring

EU	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A01, A02 F05/F05a F06/F06a	Combustion turbines/duct burner units	CO, NO_X, SO_2, PM_{10}, VOC, HAPs, NH_3	Section 12, Section 19, Section 55 40 CFR Subpart GG 40 CFR Subpart Db	Annual and short-term emission limits.	CEMS for NO_X and CO. PEMS for NH_3. Stack testing for NO_X and CO by EPA Methods as outlined in Part 70 Permit. Compliance for PM_{10}, SO_2, VOC and HAPs shall be based on sole use of pipeline quality natural gas as fuel and emission factors. Compliance for PM_{10}, SO_2, VOC and HAPs shall be based on sole use of low sulfur diesel fuel and emission factors. Recording is required for compliance demonstration.
A01, A02 F05/F05a F06/F06a	Combustion turbines/duct burner units	Opacity	AQR Section 26	Less than twenty percent opacity except for three (3) minutes in any 60-minute period.	Use of natural gas as fuel and good combustion practices as well as EPA Method 9 performance testing upon the request of the Control Officer.

EU	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A05	Auxiliary boiler	CO, NO_X, SO_2, PM_{10}, VOC, HAPs	Section 12, Section 19, Section 49, Section 55 40 CFR Subpart Db	Annual and short-term emission limits.	CEMS for NO_X and CO. PEMS for NH_3. Stack testing for NO_X and CO by EPA Methods as outlined in Part 70 Permit. Compliance for PM_{10}, SO_2, VOC and HAPs shall be based on sole use of pipeline quality natural gas as fuel and emission factors. Compliance for PM_{10}, SO_2, VOC and HAPs shall be based on sole use of low sulfur diesel fuel and emission factors. Recording is required for compliance demonstration.
A06	Auxiliary boiler	CO, NO_X, SO_2, PM_{10}, VOC, HAPs	Section 12, Section 19, Section 49, Section 55 40 CFR 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, VOC and HAPs shall be based on sole use of natural gas as fuel and emission factors. Recording is required for compliance demonstration.
A05, A06	Auxiliary boilers	Opacity	AQR Section 26	Less than twenty percent opacity except for three (3) minutes in any 60-minute period.	Sole use of natural gas as fuel and EPA Method 9 performance testing upon the request of the Control Officer.
A03, A04	Starter Engines	CO, NO_X, SO_2, PM_{10}, VOC, HAPs	Section 12, Section 19, Section 55	Annual and short-term emission limits.	Compliance for regulated pollutants shall be based on sole use of low-sulfur diesel fuel and emission factors. Recording is required for compliance demonstration.

EU	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A03, A04	Starter Engines	Opacity	AQR Section 26	Less than twenty percent opacity except for three (3) minutes in any 60-minute period.	Sole use of low-sulfur diesel fuel and EPA Method 9 performance testing upon the request of the Control Officer.

V. EMISSION REDUCTION CREDITS (OFFSETS)

The source is subject to offset requirements in accordance with Section 59 of the Clark County Air Quality Regulations. Offset requirements and associated mitigation are pollutant-specific.

VI. ADMINISTRATIVE REQUIREMENTS

Section 19 requires that DAQEM 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.

DAQEM 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:
Saguaro Power Company has supplied all the necessary information for DAQEM to draft Part 70 Operating Permit conditions encompassing all applicable requirements and corresponding compliance.

Conclusion:
DAQEM has determined that SPC will continue to determine compliance through the use of CEMS, PEMS, performance testing, quarterly reporting, and daily recordkeeping, coupled with annual certifications of compliance. DAQEM proceeds with the decision that a Part 70 Operating Permit should be issued as drafted to SPC for a period not to exceed five (5) years.