TECHNICAL SUPPORT DOCUMENT

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

SUBMITTED BY

Reliant Energy Wholesale Generation, LLC

for

Bighorn Electric Generating Station
Primm, Nevada

Part 70 Operating Permit Number: 1550
SIC Code - 4911: Electric Utility Services

Clark County
Department of Air Quality and Environmental Management
Permitting Section
February 2005

This Technical Support Document (TSD) accompanies the proposed Part 70 Operating Permit for Reliant Energy Wholesale Generation, LLC.

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

The Bighorn Electric Generating Station, owned by Reliant Energy Wholesale Generation, LLC (Reliant Energy), is located in Primm, Nevada, which is in the Ivanpah Valley airshed.

The facility consists of two 159 megawatt natural-gas turbines, each equipped with a 650 MMBtu per hour natural-gas duct burner, a 40 MMBtu per hour natural-gas auxiliary boiler, and a 500 horsepower diesel emergency generator. The potential emissions for the facility are shown in the table below.

Table 1-1: Maximum Facility PTE (tons per year)

PM_{10}	NO_X	CO	SO_2	VOC	HAP	NH_3
144.91	**157.91**	**194.07**	**10.52**	**43.51**	**10.31**	**230.30**

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

Based on information submitted by the applicant and a technical review performed by the DAQEM staff, the DAQEM proposes the issuance of a Part 70 Operating Permit to Reliant Energy.

II. FACILITY INFORMATION

A. General

Permittee	Reliant Energy Wholesale Generation, LLC
Mailing Address	7251 Amigo Street Las Vegas, Nevada 89119
Contacts	Brian McQuown – Senior Air Quality Specialist
Phone Number	(702) 407-4861
Fax Number	(702) 407-4852
Source Location	1275 East Primm Blvd. Primm, Nevada 89019
Hydrographic Area	164A
Township, Range, Section	T27S, R59E, Section 10
SIC Code	4911 – Electric Services

B. Description of Process

The Reliant Energy Wholesale Generation (Reliant Energy) facility is located in Primm, Nevada, which is approximately 35 miles southwest of Las Vegas. The facility is located in the Ivanpah Valley airshed, hydrographic area 164A. This area is designated nonattainment for ozone (i.e. NO_X and VOC) and prevention of significant deterioration (PSD) for PM_{10}, CO, and SO_2.

The facility consists of two Westinghouse 501 FD natural gas-fired combined-cycle combustion turbine/generators, each of which are equipped with dry low-NO_X burners and a heat recovery steam generator (HSRG) unit equipped with a 650 MMBtu per hour natural gas-fired duct burner for supplemental firing. The two HSRGs feed steam to a single steam turbine. The combined-cycle units each produce approximately 159 MW of electricity. The total plant net dependable rating with duct burners and the steam turbine in service is 570 MW.

Also present at the facility is a 40 MMBtu per hour natural gas-fired auxiliary boiler that is used to maintain operating temperature within each HSRG and the steam turbine during periods when the combustion turbines are offline.

Finally, there is a 500 horsepower diesel emergency fire pump on-site that will provide water for firefighting during an emergency. Fuel for the pump is stored in a 300-gallon horizontal cylinder tank.

C. Permitting History

Table II-C-1: Permits Issued to Reliant Energy

Date Issued	Permit Number	Description
11/15/2004	Modification 1, Revision 1	Change of name and ownership from Reliant Energy Bighorn, LLC to Reliant Energy Wholesale Generation, LLC
07/06/2004	Modification 1	Minor modification to accommodate as-built design changes for the auxiliary boiler
6/20/2003	Modification 0	Issuance of initial operating permit
10/01/2001	Modification 0	Issuance of initial authority to construct

Table II-C-2: BACT Determinations for Reliant Energy

E.U.	Description	BACT Technology
A01/A02	159 MW Natural Gas Combined Cycle Combustion Turbine/HSRG	SCR, dry low-NO_X burners, oxidation catalyst, natural gas combustion, inlet air filters
A03/A04	159 MW Natural Gas Combined Cycle Combustion Turbine/HSRG	SCR, dry low-NO_X burners, oxidation catalyst, natural gas combustion, inlet air filters
A05	40 MMBtu/hour Natural Gas Auxiliary Boiler	Low-NO_X burners, natural gas combustion
A06	500 hp Diesel Emergency Fire Pump	Timing retard, turbocharging, aftercooling, low sulfur diesel

D. Operating Scenario

The combustion turbines are both fired on natural gas and are allowed to operate 8,760 hours per year. The associated natural gas-fired duct burners are allowed to operate 24 hours per day and up to 3,300 hours equivalent full load per rolling 12-month period. The natural gas-fired auxiliary boiler is allowed to operate 24 hours per day and up to 2,500 hours equivalent full load per rolling 12-month period. The diesel emergency fire pump may be tested up to 52 hours per rolling 12-month period.

E. Proposed Exemptions

There are no restrictions for the operation of the diesel emergency fire pump during emergency situations.

III. EMISSIONS INFORMATION

A. Total Facility Potential to Emit

The facility potential to emit (PTE) for pollutants (Table III-A-1), as presented in the REWG Part 70 Operating Permit application, reflects the permitted emission limits established in the November 15, 2004 ATC/OP (Permit 1550, Modification 1).

Table III-A-1: Maximum Facility Potential to Emit (tons per year)

PM_{10}	NO_X	CO	SO_2	VOC	HAP	NH_3
144.91	**157.91**	**194.07**	**10.52**	**43.51**	**10.31**	**230.30**

B. Emission Units and PTE

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

Table III-B-1: Emission Units at Facility

E.U.	Description	SCC #
A01	Westinghouse 159 MW 501FD natural gas combustion turbine	20100201
A02	650 MMBtu/hr (HHV) duct burner for HRSG associated with EU A01	10100601
A03	Westinghouse 159 MW 501FD natural gas combustion turbine	20100201
A04	650 MMBtu/hr (HHV) duct burner for HRSG associated with EU A03	10100601
A05	40 MMBtu/hr auxiliary boiler	10100602
A06	500 bhp emergency diesel fire pump	20200102

Table III-B-2: Facility Potential to Emit (pounds per hour)

E.U.	PM_{10}	NO_X	CO	SO_2	VOC	HAP	NH_3
A01/A02	20.43	20.90	25.50	1.38	8.90	1.90	30.90
A03/A04	20.43	20.90	25.50	1.38	8.90	1.90	30.90
A05	0.40	1.44	2.96	0.03	0.16	0.08	0.00
A06	0.35	12.00	2.75	3.24	0.32	0.23	0.00
Total PTE	**41.61**	**55.24**	**56.71**	**6.03**	**18.28**	**4.11**	**61.80**

Table III-B-3: Facility Potential to Emit (tons per year)

E.U.	PM_{10}	NO_X	CO	SO_2	VOC	HAP	NH_3
A01/A02	72.20	77.90	95.15	5.20	21.65	5.10	115.15
A03/A04	72.20	77.90	95.15	5.20	21.65	5.10	115.15
A05	0.50	1.80	3.70	0.03	0.20	0.10	0.00
A06	<0.01	0.31	0.07	0.09	<0.01	0.01	0.00
Total PTE	**144.91**	**157.91**	**194.07**	**10.52**	**43.51**	**10.31**	**230.30**

Table III-B-4: Estimated Maximum Facility Short-term Start-up and Shut-down Emissions (pounds per hour)

PM_{10}	NO_X	CO	SO_2	VOC
34.40	**157.40**	**1,303.00**	**1.40**	**193.60**

Note: These emissions include the contribution from the HSRG units. Annual start-up and shut-down emissions are reported as a part of the facility PTE.

Table III-B-5: Enforceable Concentration Limitations for Each Turbine, (ppmvd @ 15 percent O_2), Three-hour Average, Excluding Start-up and Shut-down Events for Firing Natural Gas

E.U.	Description	CO	NO_X	NH_3
A01/A02	Turbine Unit #1	5.0	2.5	10
A03/A04	Turbine Unit #2	5.0	2.5	10

Table III-B-6: Enforceable Concentration Limitations for the Auxiliary Boiler (ppmvd @ Three Percent Oxygen) 15-Minute Average

E.U.	Description	CO	NO_X
A05	40 MMBtu/hr boiler	100	30

Table III-B-7: Estimated Hazardous Air Pollutant Emissions (HAPs)

HAP	A01-A04		A05	
	lb/hr	ton/yr	lb/hr	ton/yr
Formaldehyde	0.39	1.62	2.20E-03	2.70E-03
Benzene	0.04	0.19	5.90E-05	7.40E-05
1,3-Butadiene	1.51E-03	6.47E-03	0.00	0.00
Acrolein	0.02	0.10	0.00	0.00
Naphthalene	5.34E-03	0.02	1.80E-05	2.20E-05
Toluene	0.46	1.97	1.00E-04	1.30E-04
PAH	7.72E-03	0.03	0.00	0.00
Propylene Oxide	0.01	0.44	0.00	0.00
Acetaldehyde	0.14	0.60	0.00	0.00
Xylenes	0.23	0.96	0.00	0.00
Ethylbenzene	0.11	0.48	0.00	0.00
Dichlorobenzene	1.53E-03	2.52E-03	3.50E-05	4.40E-05
Hexane	2.29	3.78	0.05	0.07
Arsenic Compounds	2.55E-04	4.20E-04	5.90E-06	7.40E-06
Beryllium Compounds	1.53E-07	2.52E-05	3.50E-07	4.40E-07
Cadmium Compounds	1.40E-03	2.31E-05	3.20E-05	4.00E-05
Chromium Compounds	1.78E-03	2.94E-03	4.10E-05	5.10E-05
Cobalt Compounds	1.07E-04	1.76E-04	2.4E-06	3.00E-06
Manganese Compounds	4.84E-04	7.98E-04	1.10E-05	1.40E-05
Mercury Compounds	3.31E-04	5.46E-04	7.40E-06	9.60E-06
Nickel Compunds	2.67E-03	4.41E-03	5.90E-05	7.40E-05
Polycyclic Organic Matter	1.12E-03	1.89E-03	2.60E-05	3.30E-05
Selenium Compounds	3.05E-05	5.04E-05	7.10E-07	8.90E-07
Totals	**3.81**	**10.20**	**0.08**	**0.10**

Only those HAPs with a potential to exceed 0.0005 tons per year (1.0 pounds per year) are listed. These factors are being used by DAQEM to more accurately determine HAP emissions and possible source subjectivity to MACT standards per the April 2001 promulgated rule. No single facility-wide HAP emission shall exceed ten tons per year and total facility-wide HAP emissions

shall not exceed 25 tons per year. Therefore, this facility is not subject to MACT for combustion turbines. In addition, no other emission units at this facility are subject to MACT.

C. Performance Testing and Continuous Emission Monitoring

Initial performance testing for the turbines was completed on November 23, 2003, and initial performance testing for the auxiliary boiler was completed on September 24, 2003. Any additional required testing will be performed using the following methods:

Table III-C-1: Performance Testing Requirements (40 CFR 60, Appendix A)

Test Point	Pollutant	Method
Turbine/HRSG Exhaust Stack; Auxiliary Boiler Exhaust Stack	NO_X	Chemiluminescence Analyzer (EPA Method 7E, Method 20)
Turbine/HRSG Exhaust Stack; Auxiliary Boiler Exhaust Stack	CO	EPA Method 10
Turbine/HRSG Exhaust Stack	VOC	EPA Method 25A
Turbine/HRSG Exhaust Stack	NH_3 slip	Method preapproved by DAQEM/EPA
Turbine/HRSG Exhaust Stack	PM_{10}	EPA Method 201/202 or 201A/202
Turbine/HRSG Exhaust Stack; Auxiliary Boiler Exhaust Stack	Opacity	EPA Method 9
Stack Gas Parameters	---	EPA Method 1, Method 2, Method 3, Method 4

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

All performance tests on the turbine units must conform to 40 CFR 60 Subparts A and GG and 40 CFR 75. All performance tests on the auxiliary boiler must conform to AQR Section 49.

Continuous Emissions Monitoring

REWG is operating a NO_X and CO CEMS on each turbine unit. The November 15, 2004 ATC/OP contains the following requirements:

CEMS installed on emission units A01 and A03 shall demonstrate continued, direct compliance with operational limitations and the three-hour rolling average and annual emissions limitations for CO and NO_X specified in Section III of this document. The CEMS shall monitor and record the following parameters for each individual CTG:

1. exhaust gas concentration of NO_X, CO, and diluent O_2, including periods of startup and shutdown;
2. exhaust gas flow rate (by direct or indirect methods);
3. fuel flow rate;
4. hours of operation;
5. three-hour rolling averages for NO_X concentration and CO concentration;
6. hourly, daily, and quarterly accumulated mass emissions of NO_X and CO; and
7. hours of downtime for each CEMS.

Excluding start-up or shut-down periods not to exceed 180 minutes per unit per event, any exceedance of the hourly, daily, or annual CO and/or NO_X emissions limitations expressed in Section III as determined by the CEMS shall be considered a violation of the emission limit imposed and may result in enforcement action.

Reliant Energy 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 unreacted ammonia slips through the catalyst bed and out of the stack as ammonia emissions.

The PEMS uses two NO_x readings: an ammonia flow reading and several constants to calculate an estimate of ammonia emissions. One 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.

IV. 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);
3. Nevada Revised Statutes (NRS), Chapter 445B;
4. Portions of the AQR that are included in the State Implementation Plan (SIP) for Clark County, Nevada. SIP requirements are federally enforceable. All requirements from Authority to Construct permits and Section 16 Operating Permits issued by DAQEM are federally enforceable because these permits were issued pursuant to SIP-included sections of the AQR; and
5. Portions of the AQR that are not included in the SIP. These locally applicable requirements are locally enforceable only.

No discussion will be accorded to the Nevada Revised Statutes (NRS) or the Clean Air Act Amendments (CAAA) because these public laws 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 IV-A-1: AQR Section 12 and 55 Summary Table for This Facility

	PM_{10}	NO_X	CO	SO_2	VOC	HAP	TCS (NH_3)
Air Quality Area	PSD	Basic nonattainment (ozone)	PSD	PSD	Basic nonattainment (ozone)	N/A	N/A
Facility PTE (tpy)	**144.91**	**157.91**	**194.07**	**10.52**	**43.51**	**10.31**	**230.30**
Major Source	≥ 100 tpy	≥ 50 tpy	≥ 100 tpy	≥ 100 tpy	≥ 50 tpy	≥ 10 tpy for each HAP, or ≥ 25 tpy for combined HAPs	≥ 1 tpy

Discussion: Reliant Energy is a major source of PM_{10}, NO_X, CO, and TCS (NH_3). As part of the original New Source Review Analysis all of these emissions triggered notice of proposed action.

Table IV-A-2: Clark County Department of Air Quality and Environmental Management – 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 facility
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 facility
4. Control Officer	all subsections	yes	entire facility
5. Interference with Control Officer	all subsections	yes	entire facility
8. Persons Liable for Penalties - Punishment: Defense	all subsections	yes	entire facility

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
9. Civil Penalties	all subsections	yes	entire facility
10. Compliance Schedule	when applicable; applicable subsections	yes	entire facility
11. Ambient Air Quality Standards	applicable subsections	yes	entire facility
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	entire facility
14. New Source Performance Standards	CCAQR Section 14.1.56: Subpart GG Standards of Performance for Gas Turbines	no	Applicable – CTG units
16. Operating Permits	all subsections	yes	entire facility
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 facility
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 facility
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 facility
25.1 Upset/Breakdown, Malfunctions	§ 25.1 Requirements for the excess emissions caused by upset/breakdown and malfunctions	no	entire facility
25.2 Upset/Breakdown, Malfunctions	§ 25.2 Reporting and Consultation	yes	entire facility
26. Emission of Visible Air Contaminants	§ 26.1 Limit on opacity (≤ 20 percent for 3 minutes in a 60-minute period)	yes	entire facility
28. Fuel Burning Equipment	Emission Limitations for PM	yes	entire facility

Applicable Section – Title	Applicable Subsection - Title	SIP	Affected Emission Unit
29. Sulfur Contents of Fuel Oil	Sulfur content shall be equal to or less than 0.05 percent sulfur by weight	no	Fire Pump
40. Prohibitions of Nuisance Conditions	§ 40.1 Prohibitions	no	entire facility
41. Fugitive Dust	§ 41.1 Prohibitions	yes	entire facility
42. Open Burning	§ 42.2	no	entire facility
43. Odors In the Ambient Air	§ 43.1 Prohibitions coded as Section 29	no	entire facility
49. Emission Standards for Boilers and Steam Generators Burning Fossil Fuels	Local enforcement only all subsections	no	entire facility
55. Preconstruction Review for New or Modified Stationary Sources in the 8-hour Ozone Nonattainment Area	all subsections	no	entire facility
60. Evaporation and Leakage	all subsections	yes	entire facility
70. Emergency Procedures	all subsections	yes	entire facility
80. Circumvention	all subsections	yes	entire facility

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

11.1 The following concentrations of air contaminants shall not be exceeded at any single point in the ambient air:

11.1.1 Sulfur oxides as sulfur dioxide:

Annual arithmetic mean	80 $\mu g/m^3$ (0.03 ppm)
Maximum 24-hr. concentration	365 $\mu g/m^3$ (0.14 ppm)
Maximum 3-hr. concentration	1,300 $\mu g/m^3$ (0.50 ppm)

11.1.2 PM_{10}:

Annual arithmetic	50 $\mu g/m^3$
Maximum 24-hr. Concentration	150 $\mu g/m^3$

11.1.3 Carbon monoxide:

Maximum 8-hr. Concentration	10 mg/m^3 (9 ppm)
Maximum 1-hr. Concentration	40 mg/m^3 (35 ppm)

11.1.5 Nitrogen dioxide:

Annual arithmetic mean	100 $\mu g/m^3$ (0.053 ppm)

11.1.6 Ozone:

Maximum 1-hr concentration	235 $\mu g/m^3$ (0.12 ppm)
Maximum 8-hr concentration	157 $\mu g/m^3$ (0.08 ppm)

Discussion: The post-baseline increment assigned to Reliant Energy is outlined in Table IV-A-3.

Table IV-A-3: PSD Increment Consumption

Pollutant	Averaging Period	PSD Increment Consumption by the Source ($\mu g/m^3$)
PM_{10}	24-hour	4.273
PM_{10}	Annual	0.154
NO_X	Annual	0.169

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 requires notification to DAQEM of modifications, opacity testing, records of malfunctions of process equipment and/or continuous monitoring device, CEMS data, and performance test data. These requirements are found in the Part 70 OP in Sections III-D, III-E, III-F, and III-G.

DAQEM requires records to be maintained for five years, a more stringent requirement than the two years required by § 60.7.

40 CFR § 60.8-Performance tests requirements are found in the Part 70 OP in Section III-F. 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.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by § 60.8, unless otherwise specified in the applicable standard.

Discussion: Subpart GG also requires fuel monitoring and sampling to meet a standard. Subpart GG requirements are addressed in the Part 70 permit.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

Discussion: The opacity standard for the combustion turbines is zero percent, except for three minutes in any 60-minute period where the opacity shall not exceed 20 percent. A Method 9 test shall be performed initially and every two years thereafter per Condition III-F-6 of the Part 70 operating permit.

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

Discussion: Section 26 of the AQR is more stringent than the federal opacity standards, setting a maximum of 20 percent obscurity except for three minutes in any 60-minute period.

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

Discussion: Reliant Energy shall operate in a manner consistent with this section of the regulation.

40 CFR § 60.12- Circumvention prohibition is Condition I-A-27 in the Part 70 OP. This is also local rule § 80.1.

40 CFR § 60.13-Monitoring requirements.
This section requires that CEMS meet Appendix B and Appendix F standards of operation, testing and performance criteria. Section III-E of the Part 70 OP contains the CEMS conditions and citations to Appendix B and F. In addition, the QA plan approved for the CEMS follows the requirements outlined including span time and recording time.

Subpart GG-Standards of Performance for Stationary Gas Turbines

40 CFR § 60.330-Applicability and designation of affected facility.
(a) The provisions of this subpart are applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10.70 gigajoules per hour (ten MMBtu per hour), based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of § 60.332. [44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987]

Discussion: The two combined-cycle turbines began construction in 2001. The lower heating value of the natural gas fuel is above the ten MMBtu per hour threshold. Subpart GG shall apply to both EUs A01 and A03.

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

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.
   (1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

   STD = 0.0075 x 14.4/Y + F

   where:
   STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).
   Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.
   F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.

Discussion: Per the application for the Title V operating permit, the NSPS NO_X emission limit is calculated with a heat rate of 1.0548 kilojoules/Btu. Assuming that there are 8.29 Btus per watt-hour, the value of Y in this equation is 8.74 kilojoules per watt-hour. Because the facility uses PUC natural gas, the F factor is zero. Therefore:

0.0075 x 14.4/8.74 + 0 = 0.0124 percent by volume at 15 percent oxygen
0.0124 volume% x (10,000 ppm/volume%) = 124 ppmv NO_X at 15 percent oxygen

Reliant Energy shall comply with this standard.

40 CFR § 60.333-Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.
(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

Discussion: The use of pipeline quality PUC natural gas will satisfy this regulation. This is stipulated in Condition III-C-7 of the Part 70 operating permit. The sulfur is limited to 0.75 grains per 100 dry standard cubic feet in Condition III-D-4.

40 CFR § 60.334-Monitoring of operations.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Discussion: This requirement is stipulated in Condition III-D-4 of the Part 70 operating permit. Sulfur content shall be verified annually and based on data from the gas supplier.

40 CFR § 60.335-Test methods and procedures.

(b) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in § 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in §§ 60.332 and 60.333(a) as follows:

(2) The monitoring device of § 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with § 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 100 ppm of nitrogen oxide and 21 percent oxygen. The NO_X emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

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

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

40 CFR § 60.40a - Applicability

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:
  (1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and
  (2) For which construction or modification is commenced after September 18, 1978.

(b) Unless and until subpart GG of this part extends the applicability of subpart GG of this part to electric utility steam generators, this subpart applies to electric utility combined cycle gas

turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG of this part.)

Discussion: The duct burners (EUs: A02, A04) are subject to the provisions of this subpart. They each have a rated capacity of 650 MMBtu per hour.

40 CFR § 60.42a – Standard for Particulate Matter

(a) On and after the date on which the performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:
   (1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

Discussion: The manufacturer's performance data for the duct burners state that particulate emissions from the combustion of natural gas will yield 0.01 pounds per MMBtu. Reliant Energy shall be in compliance with this regulation.

(b) On and after the date the particulate matter performance test required to be conducted under Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

Discussion: Condition III-C-10 in the Part 70 operating permit states that there will zero opacity from each turbine/duct burner stack except for three minutes in any 60-minute period when visible emissions shall not exceed 20 percent. This is more stringent than the NSPS limits.

40 CFR § 60.43a – Standard for Sulfur Dioxide

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section), any gases which contain sulfur dioxide in excess of:
   (1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or
   (2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

Discussion: The manufacturer's performance data for the duct burners states that particulate emissions from the combustion of natural gas will yield 0.0006 pounds per MMBtu. Reliant Energy shall be in compliance with this standard.

40 CFR § 60.44a – Standard for Nitrogen Oxides

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:
   (1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.

Discussion: According to the manufacturer, the duct burners operate at a full load input of 633 MMBtu per hour HHV and will contribute approximately 63 pounds per hour of NO_X emissions. Therefore, the emission rate can be calculated as follows:

63 pounds/hour / 633 MMBtu/hour = 0.10 pounds NO_X per MMBtu

Reliant Energy shall be in compliance with this standard.

40 CFR § 60.46a – Compliance Provisions

(c) The particulate matter emission standards under § 60.42a and the nitrogen oxides emission standards under § 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.

Discussion: Reliant Energy has separate emission standards during startup and shutdown. They are outlined in Table III-A-4 in the Part 70 operating permit.

(e) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under § 60.43a and the nitrogen oxides emission limitations under § 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under § 60.43a and the nitrogen oxides emission limitation under § 60.44a is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.47a of this subpart, compliance of the affected facility with the emission requirements under §§ 60.43a and 60.44a of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

Discussion: Reliant Energy has completed all compliance demonstrations and has demonstrated compliance with all applicable emission standards for NO_X and SO_2.

(j) *Compliance provisions for duct burners subject to § 60.44a(a)(1).* To determine compliance with the emissions limits for NO_x required by § 60.44a(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under § 60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under § 60.44a(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system specified under § 60.47a for measuring NO_x and oxygen and meet the requirements of § 60.47a. Data from a CEMS certified (or recertified) according to the provisions of 40 CFR 75.20, meeting the QA and QC requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used. The sampling site shall be located at the outlet from the steam generating unit. The NO_x emission rate at the outlet from the steam generating unit shall constitute the NO_x emission rate from the duct burner of the combined cycle system.

Discussion: Reliant Energy employs the use of CEMS on each of the turbine stacks to monitor NO_X emissions. The measurements to be taken are outlined in Condition III-E-1 in the Part 70 operating permit.

40 CFR § 60.47a – Emission Monitoring

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

Discussion: The duct burners combust only natural gas; therefore, COMS are not required.

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

Discussion: The duct burners combust only natural gas; therefore, SO_2 CEMS are not required.

(c) (1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49a. Data reported to meet the requirements of § 60.49a shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

Discussion: Reliant Energy is subject to the requirements of 40 CFR 75; therefore, the data acquired by the NO_X CEMS are allowed to be used to show compliance with both 40 CFR 60 Subpart Da and 40 CFR 75. The reporting requirements are outlined in Section III-H of the Part 70 operating permit.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

Discussion: Reliant Energy has installed a diluent oxygen CEMS. Monitoring requirements are outlined in Section III-E of the Part 70 operating permit.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) The owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph § 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under § 60.46a. The 1-hour averages are calculated using the data points required under § 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.
(2) Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.
(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.
(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under 60.13(c) and calibration checks under 60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.
(1) Methods 3B, 6, and 7 shall be used to determine O_2, SO_2, and NO_x concentrations, respectively.
(2) SO_2 or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.
(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:
Fossil fuel Span value for nitrogen oxides (ppm)
Gas 500
(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.
(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:
(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under § 60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.
(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.
(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.
(4) For Method 3B, Method 3A may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under § 60.44a(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.
(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.
(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 50 percent of the gross thermal output of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with the output-based standard under § 60.44a(d)(1) shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or (m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

Discussion: Monitoring requirements are outlined in Section III-E of the Part 70 operating permit.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR part 75.

(o) The owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_x standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

Discussion: The duct burners exhaust through the same stack as the combustion turbines; therefore, the monitors required for monitoring turbine emissions will also monitor duct burner emissions.

40 CFR § 60.48a – Compliance Determination Procedures and Methods
The compliance demonstration for this facility is discussed in Section III-D of the Part 70 operating permit.

40 CFR § 60.49a – Reporting Requirements are discussed in Section III-H of the Part 70 operating permit.

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

40 CFR § 60.40c – Applicability and Delegation of Authority

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

Discussion: The auxiliary boiler (EU: A05) is rated at 40 MMBtu per hour; therefore, Subpart Dc is applicable to this emission unit.

40 CFR § 60.42c – Standard for Sulfur Dioxide

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

40 CFR § 60.43c – Standard for Particulate Matter

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

40 CFR § 60.48c – Reporting and Recordkeeping Requirements are addressed in Sections III-G and III-H in the Part 70 operating permit.

40 CFR PART 64-COMPLIANCE ASSURANCE MONITORING

40 CFR § 64.2 – Applicability

(a) General applicability. Except for backup utility units that are exempt under paragraph (b)(2) of this section, the requirements of this part shall apply to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria:
  (1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of this section;
  (2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and
  (3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, ‘‘potential pre-control device emissions’’ shall have the same meaning as ‘‘potential to emit,’’ as defined in § 64.1, except that emission reductions achieved by the applicable control device shall not be taken into account.

(b) Exemptions
  (1) Exempt emission limitations or standards. The requirements of this part shall not apply to any of the following emission limitations or standards:
    (i) Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act.
    (ii) Stratospheric ozone protection requirements under title VI of the Act.
    (iii) Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act.

(iv) Emission limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions within a source or between sources.
(v) An emissions cap that meets the requirements specified in § 70.4(b)(12) or § 71.6(a)(13)(iii) of this chapter.
(vi) Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in § 64.1. The exemption provided in this paragraph (b)(1)(vi) shall not apply if the applicable compliance method includes an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device (such as a surface coating line controlled by an incinerator for which continuous compliance is determined by calculating emissions on the basis of coating records and an assumed control device efficiency factor based on an initial performance test; in this example, this part would apply to the control device and capture system, but not to the remaining elements of the coating line, such as raw material usage).

Discussion: Reliant Energy is major for PM_{10}, NO_X, CO, and NH_3. Control devices are used on the combustion turbines/duct heaters (EUs: A01-A04) for NO_X and CO; therefore, PM_{10} and NH_3 emissions are not subject to CAM. There are no control devices on the auxiliary boiler (EU: A05) or the fire pump (EU: A06), so neither emission unit is subject to CAM.

The turbines at Reliant Energy are subject to the NO_X emissions limits of 40 CFR 60 Subpart GG, which was promulgated in 1979; therefore, the exemption listed in § 64.2(b)(1)(i) does not apply. However, the facility is subject to the provisions of the acid rain program per § 64.2(b)(1)(iii). This qualifies the NO_X emissions at Reliant Energy for an exemption from CAM.

The turbines at Reliant Energy are subject to the CO emission limits presented in the facilities ATC/OP. There are no promulgated NSPS or DAQEM emission limits; therefore, the exemption listed in § 64.2(b)(1)(i) does not apply. Because none of the exemptions in § 64.2(b) applies to the CO emissions at this facility, the turbines at Reliant Energy are subject to CAM for CO.

Reliant Energy shall comply with the CAM rule through the CO CEMS that are installed on the turbine exhaust stacks.

40 CFR PART 72-ACID RAIN PERMITS REGULATION

Subpart A – Acid Rain Program General Provisions

40 CFR § 72.6 – Applicability

(a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:
  (1) unit listed in table 1 of § 73.10(a) of this chapter.
  (2) A unit that is listed in table 2 or 3 of § 73.10 of this chapter and any other existing utility unit, except a unit under paragraph (b) of this section.
  (3) A utility unit, except a unit under paragraph (b) of this section, that:
    (i) Is a new unit; or
    (ii) Did not serve a generator with a nameplate capacity greater than 25 MWe on November 15, 1990 but serves such a generator after November 15, 1990.
    (iii) Was a simple combustion turbine on November 15, 1990 but adds or uses auxiliary firing after November 15, 1990;
    (iv) Was an exempt cogeneration facility under paragraph (b)(4) of this section but during any three calendar year period after November 15, 1990 sold, to a utility power distribution system, an annual average of more than one-third of its potential electrical output capacity and more than 219,000 MWe-hrs electric output, on a gross basis;
    (v) Was an exempt qualifying facility under paragraph (b)(5) of this section but, at any time after the later of November 15, 1990 or the date the facility commences commercial operation, fails to meet the definition of qualifying facility;
    (vi) Was an exempt IPP under paragraph (b)(6) of this section but, at any time after the later of November 15, 1990 or the date the facility commences commercial operation, fails to meet the definition of independent power production facility; or
    (vii)Was an exempt solid waste incinerator under paragraph (b)(7) of this section but during any three calendar year period after November 15, 1990 consumes 20 percent or more (on a Btu basis) fossil fuel.

Discussion: Reliant Energy is defined as a utility unit in the definitions for Part 72; therefore, the provisions of this regulation apply.

40 CFR § 72.9 – Standard Requirements

(a) *Permit Requirements.*
  (1) The designated representative of each affected source and each affected unit at the source shall:
    (i) Submit a complete Acid Rain permit application (including a compliance plan) under this part in accordance with the deadlines specified in § 72.30;
    (ii) Submit in a timely manner a complete reduced utilization plan if required under § 72.43; and
    (iii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.
  (2) The owners and operators of each affected source and each affected unit at the source shall:
    (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
    (ii) Have an Acid Rain Permit.

(b) *Monitoring Requirements.*
  (1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in part 75 of this chapter.
  (2) The emissions measurements recorded and reported in accordance with part 75 of this chapter shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
  (3) The requirements of part 75 of this chapter shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

(c) *Sulfur Dioxide Requirements.*
  (1) The owners and operators of each source and each affected unit at the source shall:
    (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under § 73.34(c) of this chapter) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
    (ii) Comply with the applicable Acid Rain emissions limitation for sulfur dioxide.
  (2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
  (3) An affected unit shall be subject to the requirements under paragraph (c)(1) of this section as follows:
    (i) Starting January 1, 1995, an affected unit under § 72.6(a)(1);
    (ii) Starting on or after January 1, 1995 in accordance with §§ 72.41 and 72.43, an affected unit under § 72.6(a) (2) or (3) that is a substitution or compensating unit;
    (iii) Starting January 1, 2000, an affected unit under § 72.6(a)(2) that is not a substitution or compensating unit; or
    (iv) Starting on the later of January 1, 2000 or the deadline for monitor certification under part 75 of this chapter, an affected unit under § 72.6(a)(3) that is not a substitution or compensating unit.
  (4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
  (5) An allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1)(i) of this section, prior to the calendar year for which the allowance was allocated.
  (6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under §§ 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
  (7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

(d) *Nitrogen Oxides Requirements.* The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

(e) *Excess Emissions Requirements.*
  (1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under part 77 of this chapter.

(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by part 77 of this chapter; and
  (ii) Comply with the terms of an approved offset plan, as required by part 77 of this chapter.

(f) *Recordkeeping and Reporting Requirements.*
  (1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority.
    (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with § 72.24; *provided* that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative.
    (ii) All emissions monitoring information, in accordance with part 75 of this chapter; *provided* that to the extent that part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
    (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program.
    (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
  (2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under subpart I of this part and part 75 of this chapter.

(g) *Liability.*
  (1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under § 72.7 or § 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
  (2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
  (3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
  (4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
  (5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
  (6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under § 72.41 (substitution plans), § 72.42 (Phase I extension plans), § 72.43 (reduced utilization plans), § 72.44 (Phase II repowering extension plans), § 74.47 of this chapter (thermal energy plans),

and § 76.11 of this chapter (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under part 75 of this chapter (including §§ 75.16, 75.17 and 75.18 of this chapter), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of this part, parts 73, 74, 75, 76, 77, and 78 of this chapter, by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

(h) *Effect on Other Authorities.* No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under § 72.7 or § 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans.

(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act.

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law.

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Discussion: Reliant Energy has applied for all of the proper permits under this regulation. An ORIS Code (#55687) for emission units BHG1 and BHG2 (EUs: A01/A02, A03/A04) has been obtained. A Certificate of Representation for Designated Representative has been registered with Robert W. Lawhn as the primary representative and Brian McQuown as the alternate representative.

Subpart B – Designated Representative
Reliant Energy has a Certificate of Representation for Designated Representative on file. They have fulfilled all requirements under this subpart.

Subpart C – Acid Rain Permit Applications
Reliant Energy has applied for an acid rain permit.

Subpart D – Acid Rain Compliance Plan and Compliance Options
This subpart discusses the individual requirements necessary for a complete compliance plan. A compliance plan exists for each combustion turbine.

Subpart E – Acid Rain Permit Contents
Reliant Energy has applied for an acid rain permit, and it will contain all information to demonstrate compliance with this subpart.

40 CFR PART 73 – ACID RAIN SULFUR DIOXIDE ALLOWANCE SYSTEM

Subpart A – Background and Summary

§ 73.1 Purpose and scope.
The purpose of this part is to establish the requirements and procedures for the following:
(a) The allocation of sulfur dioxide emissions allowances;
(b) The tracking, holding, and transfer of allowances;
(c) The deduction of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to parts 72 and 77 of this chapter;
(d) The sale of allowances through EPA-sponsored auctions and a direct sale, including the independent power producers written guarantee program; and
(e) The application for, and distribution of, allowances from the Conservation and Renewable Energy Reserve.
(f) The application for, and distribution of, allowances for desulfurization of fuel by small diesel refineries.

§ 73.2 Applicability.
The following parties shall be subject to the provisions of this part:
(a) Owners, operators, and designated representatives of affected sources and affected units pursuant to § 72.6 of this chapter;
(b) Any new independent power producer as defined in section 416 of the Act and § 72.2 of this chapter, except as provided in section 405(g)(6) of the Act;
(c) Any owner of an affected unit who may apply to receive allowances under the Energy Conservation and Renewable Energy Reserve Program established in accordance with section 404(f) of the Act;
(d) Any small diesel refinery as defined in § 72.2 of this chapter, and
(e) Any other person, as defined in § 72.2 of this chapter, who chooses to purchase, hold, or transfer allowances as provided in section 403(b) of the Act.

Discussion: Reliant Energy is an affected source pursuant to § 72.6 of this chapter because it fits the definition of a utility unit; therefore, this regulation shall apply.

Subpart B – Allowance Allocations
Reliant Energy is not listed on either the Phase I or Phase II tables because it is a newer power plant; therefore, it will not have an initial allocation per § 73.10.

Subpart C – Allowance Tracking System
Reliant Energy is considered a new unit. A complete certificate of representation has been received and an account has been established for this facility. Reliant Energy shall follow all guidelines and instructions presented in this subpart while maintaining its allowance account.

Subpart D – Allowance Transfers
When an allowance transfer is necessary, Reliant Energy shall follow all procedures in this subpart.

Subpart E – Auctions, Direct Sales, and Independent Power Producers Written Guarantee
This subpart outlines the auction process for allowance credits.

Subpart F – Energy Conservation and Renewable Energy Reserve

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

40 CFR PART 75-CONTINUOUS EMISSION MONITORING

Subpart A – General

40 CFR § 75.2 – Applicability

(a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_x.

Discussion: Reliant Energy is subject to the Acid Rain emission limitations of 40 CFR Part 72; therefore, the facility is subject to the monitoring requirements of this regulation.

Each combined cycle turbine unit has been equipped with both a NO_X CEMS and diluent oxygen monitors. Each turbine unit is also equipped with a fuel flow monitor. Each turbine unit also has a CO CEMS and a CEMS-equivalent monitoring device to measure ammonia emissions. The data from the CEMS are used to provide quarterly acid rain reports to both EPA and DAQEM.

All required monitoring plans, RATA testing protocols, and certification testing reports have been provided to EPA and DAQEM. Initial CEMS certification testing was completed on November 23, 2003. The CEMS Quality Assurance Plan was submitted to DAQEM on February 12, 2003 and approved on August 11, 2003.

V. 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:

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, any additional annual records required, and Annual Certification of Compliance

(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. Summary of Monitoring for Compliance

Emission Unit #	Process Description	Monitored Pollutants	Applicable Subsection Title	Requirements	Compliance Monitoring
A01/A02 A03/A04	Combustion turbines units	CO, NO_X, SO_2, PM_{10}, VOC, HAPs, NH_3	Section 12, Section 19, Section 55 40 CFR Subpart GG	Annual and short-term emission limits.	CEMS for NO_X and CO. Stack testing by EPA Methods as approved by DAQEM and EPA in current ATC/OP. Compliance for HAPs and non-CEMS monitored emissions shall be based on fuel consumption and emission factors. PEMS for NH_3 Recording is required for compliance demonstration.
A01/A02 A03/A04	Combustion turbines units	Opacity	Subpart GG AQR Section 26	Opacity = 0%, except for 3 min. out of every 60 min. period when Opacity ≤ 20%	EPA Method 9 performed every two years
A05	Auxiliary Boiler	Opacity	AQR Section 26	Opacity = 20%, except for 3 min. out of every 60 min. period when Opacity ≤ 60%	Per the request of the Control Officer
A06	Diesel Fire Pump	Opacity	AQR Section 26	Opacity = 20%, except for 3 min. out of every 60 min. period when Opacity ≤ 60%	Per the request of the Control Officer

VI. 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.

VII. 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:

Reliant Energy 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 Reliant Energy will continue to determine compliance through the use of CEMS, performance testing, quarterly reporting, daily recordkeeping, coupled with annual certifications of compliance. DAQEM proceeds with the preliminary decision that a Part 70 Operating Permit should be issued as drafted to Reliant Energy for a period not to exceed five years.