URS

DOCKET	
09-AFC-1	
DATE	NOV 18 2009
RECD	NOV 19 2009

November 18, 2009

Dockets Unit
California Energy Commission
1516 Ninth Street, MS 4
Sacramento, CA 95814-5512

Re: Watson Cogeneration Steam and Electric Reliability Project
Application for Certification 09-AFC-1

On behalf of Watson Cogeneration Company, the applicant for the above-referenced Watson Cogeneration Steam and Electric Reliability Project, we are pleased to submit the following:

- November 11, 2009 Letter of Response to South Coast Air Quality Management District Questions.

The enclosed document is being submitted to the CEC for docketing per our agreement to CEC Data Request No. 9.

We have included 1 hard copy and 1 CD.

Sincerely,
URS Corporation

C Kyle-Fischer

Cindy Kyle-Fischer
Project Manager

Enclosures

cc: Ross Metersky, BP Products North America, Inc.

URS Corporation
8181 East Tufts Avenue
Denver, CO 80237
Tel: 303.694.2770
Fax: 303.694.3946

ATMOSPHERIC DYNAMICS
METEOROLOGICAL AND AIR QUALITY MODELING

November 11, 2009

South Coast Air Quality Management District
Attention: Rafik Beshai
Refinery and Waste Management Permitting
21865 Copley Drive
Diamond Bar, CA 91765-4182

Subject: **Additional Information Request for Watson Cogeneration Steam and Electric Reliability Project, A/Ns 496922, 496924, and 496925.**

Dear Mr. Beshai,

This letter is the response to the additional information requests, made via our September 23rd meeting with follow up emails on September 25th and October 23rd, 2009 for the above stated permit applications. The information requested is as follows:

Question 1: *Control Equipment Design Specifications – BP will re-submit District forms (e.g. Form 400-E-5 and Form 400-E-12) and any additional descriptive write-up with latest design specifications. As we discussed, normally the District requires that the equipment vendor be selected prior to submittal of an application for a Permit to Construct (PC). The specifications for equipment planned to be installed would then be described in the application. We understand that at this point the vendor for control equipment for the Watson fifth train has not yet been selected. At this point, we would like to see the design specifications (with expected performance specifications) for equipment BP will most likely select. Then BP would choose equipment with performance specifications at least as stringent as the unit for which information was submitted.*

Answer: The detailed design specifications are currently being prepared by the projects design engineer. Once this data is finalized, updated SCAQMD forms 400-E-5 and 400-E-12 will be submitted. Additional design data, including the vendor guarantees will also be provided to the SCAQMD.

Question 2: *Information in your application (Form 400-E-12) indicates that the rating of the gas turbine is 94,000 kW, even though in the remainder of the application and in CEC literature the gas turbine is described as an 85 MW unit. Should the permit equipment description for the gas turbine reflect a rating of 94 MWe (net)?? Further in Table 3-2 of the application, the listed net output varies from 78,382 kW to 90,537 kW, indicating that under certain full load conditions net electric output will exceed 85 MWe.*

Answer: A revised form 400-E-12 has been included which correctly lists the net project generation at 85 MW.

Question 3: *The District has considered BACT for natural gas/refinery gas fired cogeneration units. BACT standards, to which the new BP Watson cogeneration unit must comply, are stated below:*

> *The District agrees with BP's proposed standard for NOx of 2ppm @ 15% O2, 1-hour average.*
>
> *BP originally proposed a limitation of CO of 4 ppm, 3-hour average. In your reply of July 17, 2009, BP agrees to comply with a limitation of 3 ppm CO. The District proposes the following BACT limitations for CO (note: both limits will be included in the permit): 3 ppm CO at 15% O2, 1-hour average; and 2 ppm CO @ 15% O2, 3-hour average.*
>
> *BP has proposed a limitation of total reduced sulfur content in the refinery fuel gas of 40 ppm, calculated as H2S (note: no averaging time is stated in the application). The District now proposes the following BACT limitations for total sulfur content in the refinery fuel gas (note: both limits will be included in the permit): 30 ppm Total Reduced Sulfur calculated as H2S, 24-hour average; and 40 ppm Total Reduced Sulfur calculated as H2S, 3-hour average. It should be noted that blending of the refinery gas with natural gas is permissible. Of course blending of refinery gas with natural gas would result in reduced usage of refinery gas.*
>
> *BP has proposed a limitation for VOC of 2 ppm. The District agrees with this and will include the following limitation in the permit: 2 ppm VOC @ 15% O2, 1-hour average.*
>
> *BP has proposed a limitation for ammonia slip of 5 ppm. The District agrees with this and will include the following limitation in the permit: 5 ppm NH3 @ 15% O2, 1-hour average.*

Answer: The project emissions for CO have been revised to reflect CO of 3.0 ppm 1-hour average and CO of 2.0 ppm on a 3-hour average. The attached project emissions tables reflect a CO limit of 3.0 ppm.

The refinery is currently analyzing the ability to meet the 40 ppm (3-hour average) and the 30 ppm (24-hour average) sulfur limit.

Question 4: *As you are aware, the District is under a permit moratorium from issuing permits which involve an offset exemption under Rule 1304. Based on recent legislative action in Sacramento, the District expects that this moratorium will remain in effect under January 1, 2010. After January 1, 2010, the District will be able to issue permits which involve offset exemption, such as Concurrent Facility Modification (as required by the Watson fifth train project). Therefore, at the time that the Preliminary Determination of Compliance (PDOC) is required by the CEC (November 25, 2009), this issue may not be resolved.*

Answer: BP understands the current permit moratorium.

Question 5: *Based on the component count in Table I-A-13 (for existing Cogeneration Unit No. 1), VOC emissions from fugitive components of 185 lbs/day - 30-day average - are expected. ERCs for this increase, in addition to the emissions from the gas turbine/duct burner must be provided (note: this rate must further be multiplied by an offset factor of 1.2). Therefore, it is again requested that BP finalize the design and provide an accurate fugitive component count (for equipment in gas/vapor, light liquid, and heavy liquid service), so that required ERCs for the VOC emissions increase can be accurately determined. Of course, the fugitive components used in the fifth train must meet current BACT standards.*

Answer: An updated component count has been prepared for the new cogeneration unit and is attached. It is estimated that up to 90 percent of the valve components on the fifth train will employ the use of bellow seals which meet current BACT standards. Based on the revised component count, the emissions of fugitive VOCs from the fifth train will be 51.17 lbs/day. After applying the offset ratio of 1.2:1, the additional ERCs needed will be 61.4 lb/day. The calculation methodology has been included with this response.

Question 6: *The District understands that BP is willing to accept an annual NOx emissions limit of 39.9 tons. This limit is below the "Significant Emissions Increase" level stated in District Regulation XVII – PSD. Please provide details regarding how the annual emissions rates stated in the AFC are calculated (e.g. please write out the calculation to show the values of each parameter). Further, emissions offsets (i.e. ERCs) are based on monthly emissions divided by 30. Therefore, it is important to see details of the monthly emissions calculations (for determination of required ERCs).*

Answer: The annual NO_x emissions will be limited to less than 40 tons per year. This emission limit was calculated using the following formula and assumptions.

Annual NO_x = (8720 hr/yr * 9.0 lb/hr) + (4 cold starts * 211.24 lb/event) + (12 hot starts * 21.324 lb/event) + (16 shutdowns * 12.848 lb/event) = 79,786.42 lb/year = **39.89 tpy**.

Assumptions:

- Annual NOx based on annual average temperature and average duct firing rate of 9 lb/hr.
- Each cold start is 3 hours with 4 events per year
- Each hot start is 1 hour with 12 events per year
- Each shutdown is 1 hour with 16 events per year

This calculation methodology along with the calculation of the ERCs for each applicable pollutant is included as an attachment.

Question 7: *Please submit revised emissions tables for your application, based on the new BACT standards which were communicated to BP in an e-mail message on September 18, 2009 and with which BP has agreed to comply in Wednesday's meeting.*

Answer: The revised emissions tables for CO are included as an attachment.

Question 8: *Tran Vo made a request of BP, at the CEC public meeting, to perform a BACT analysis of SCONOX technology. Please submit either an amended BACT determination addressing this technology, or a write-up which would be an addendum to the BACT determination in the AFC. Typically, facilities have performed what is called top-down BACT analysis, which includes the following elements: Identify Available Control Technologies, Eliminate Technically Infeasible Options, Rank and Evaluate Remaining Technologies, and Select BACT.*

Answer: Please see the attached BACT analysis for SCONOx.

Question 9: *Would BP be willing to install a SOx CEMS to monitor and record SOx concentration at the exhaust stack of the cogen unit?? The application states that this is currently not planned. Since the cogen unit will be a major SOx source under RECLAIM, I do not think that not having a SOx CEMS is in compliance with Rule 2011. I understand that the four existing cogen units are all equipped with SOx CEMS. The reason that a SOx CEMS is requested is that this would be used to measure total SOx emissions from all fuels fired. The current plan is to measure fuel sulfur in the refinery gas to show compliance with the BACT refinery fuel sulfur limit and to report SOx emissions under RECLAIM. However, sulfur in the natural gas would not be accounted for. Rule 2011, Chapter 2 requires a CEMS for each type of fuel fired on by a major SOx source.*

Answer: BP will install a SOx CEMS to monitor and record SOx concentration data for the proposed fifth train.

Question 10: *BP states in the submittal that a CAM plan is not required. The reason cited is that CEMS will be used to monitor pollutant emissions. However, the permit will state a BACT limit for VOC concentration, but there will be no CEMS to monitor VOC emissions. The permit will include a requirement to monitor and record the gas temperature at the inlet of the SCR/Oxidation Catalyst and to maintain the temperature above 500°F. The Oxidation Catalyst and temperature monitoring and recording are subject to CAM.*

Answer: A CAM plan will be submitted for VOC which will be controlled by the use of an oxidation catalyst. As the District has proposed for a permit condition, the CAM plan will propose that the monitoring of the oxidation catalyst as well as the use of a CO CEMs will be used as indicators of proper operation of the oxidizer.

Please review the responses and attached additional data that was used to support our answers to your questions. If you have any additional questions or comments, please call me at (805) 569 6555.

Regards.
Atmospheric Dynamics, Inc.

Gregory Darvin

Cc:
Ross Metersky (BP)
John Shao (BP)
Miles Heller (BP)
Alan Seese (BP)
Scott Hawley (BP)
Eric Daley (BP)
Cindy Kyle-Fischer (URS)

Question 2 Support Data

South Coast Air Quality Management District

FORM 400-E-12
GAS TURBINE

Mail Application To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765

Tel: (909) 396-3385
www.aqmd.gov

This form must be accompanied by a completed Application for a Permit to Construct/Operate -Form 400A, Form CEQA, Plot Plan and Stack Form

Permit to be Issued to (Business name of operator to appear on permit):
BP West Coast Products LLC-BP Carson Refinery

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site):
2350 E. 23rd Street — (●) Fixed Location ( ) Various Locations

SECTION A: EQUIPMENT INFORMATION

Turbine	**Manufacturer:** GE **Model No.:** 7EA — **Serial No.:** **Size (based on Higher Heating Value - HHV):** **Manufacturer Maximum Input Rating:** 1069.900 MMBTU/hr ____ kWh **Manufacturer Maximum Output Rating:** ____ MMBTU/hr 85000.00 kWh
Function (Check all that apply)	[X] Electrical Generation [ ] Driving Pump/Compressor [ ] Emergency Peaking Unit [X] Steam Generation [ ] Exhaust Gas Recovery [ ] Other (specify):
Cycle Type	( ) Simple Cycle ( ) Regenerative Cycle (●) Combined Cycle ( ) Other (specify):
Combustion Type	( ) Tubular ( ) Can-Annular ( ) Annular
Fuel (Turbine)	(●) Natural Gas ( ) LPG ( ) Digester Gas* ( ) Landfill Gas* ( ) Propane (●) Refinery Gas* ( ) Other* : * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).
Heat Recovery Steam Generator (HRSG)	**Steam Turbine Capacity** ____ MW **Low Pressure Steam Output Capacity:** ____ lb/hr @ ____ °F **High Pressure Steam Output Capacity:** ____ lb/hr @ ____ °F **Superheated Steam Output Capacity:** 624000.0 lb/hr @ ____ °F
Duct Burner	**Manufacturer:** JohnZink or equivalent — **Model:** **Number of burners:** 2 — **Rating of each burner (HHV):** 510 MMBTU/HR – TOTAL **Type:** (●) Low NOx (please attach manufacturer's specifications) ( ) Other: Show all heat transfer surface locations with the HRSG and temperature profile
Fuel (Duct Burner)	(●) Natural Gas ( ) LPG ( ) Digester Gas* (●) Refinery Gas* ( ) Landfill Gas* ( ) Propane ( ) Other* : *(If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).

Air Pollution Control	(●) Selective Catalytic Reduction (SCR)* ( ) Selective Non-catalytic Reduction (SNCR)* (●) Oxidation Catalyst* ( ) Other (specify)* ______ ( ) Steam/Water Injection: Injection Rate: ______ lbs. water/lbs. fuel, or ______ mole water/mole fuel * Separate application is required.
	Capital Cost: ______ | Installation Cost: ______ | Annual Operating Cost: ______
Oxidation Catalyst Data (If Applicable)	Manufacturer: ______ | Model: ______
	Catalyst Dimensions: Length: ___ ft. ___ in. Width: ___ ft. ___ in. Height: ___ ft. ___ in.
	Catalyst Cell Density: ______ cells/sq. in. | Pressure Drop Across Catalyst: ______
	Manufacturer's Guarantee — CO Control Efficiency: ___ % Catalyst Life: ___ yrs. VOC Control Efficiency: ___ % Operating Temp. Range: ___ °F
	Space Velocity (gas flow rate/catalyst volume): ______ | Area Velocity (gas flow/wetted catalyst surface area): ______
	VOC Concentration into Catalyst: ___ PPMVD @ 15 % O_2 | CO Concentration into Catalyst: ___ PPMVD @ 15 % O_2

SECTION B: OPERATION INFORMATION

On-line Emissions Data

Pollutants	Maximum Emissions Before Control*		Maximum Emissions After Control	
	PPM@15% O_2 dry	lb/Hour	PPM@15% O_2 dry	lb/Hour
ROG				
NOx				
CO				
PM10				
SOx				
NH3				

* Based on temperature, fuel consumption, and MW output

Reference (attach data):
[X] Manufacturer Emission Data [ ] EPA Emission Factors [ ] AQMD Emission Factors [ ] Source Test

Stack or Vent Data	Stack Height: 100 ft. ___ in. Stack Diameter: 15 ft. 6.000 in. Exhaust Temperature: 385.00 °F Exhaust Pressure: ___ inches water column Exhaust Flow Rate: 864383.0 CFM Oxygen Level: ___ %
Operating Schedule	Normal: 24 hours/day 7 days/week 52 weeks/yr Maximum: 24 hours/day 7 days/week 52 weeks/yr

Startup Data	No. of Startups per day:	No. of Startups per year:	Duration of each startup: hours		
Shutdown Data	No. of Shutdowns per day:	No. of Shutdowns per year:	Duration of each shutdown: hours		

Startup and Shutdown Emissions Data

Pollutants	Startup Emissions		Shutdown Emissions	
	PPM @15% O_2, dry	lb/Hour	PPM @15% O_2, dry	lb/Hour
ROG				
NOx				
CO				
PM10				
SOx				
NH3				

Monitoring and Reporting

Continuous Emission Monitoring System (CEMS)

CEMS Make:

CEMS Model:

Will the CEMS be used to measure both on-line and startup/shutdown emissions? ● Yes ○ No

The following parameters will be continuously monitored:

☒ NOx ☒ CO ☒ O_2

☒ Fuel Flow Rate ☒ Ammonia Injection Rate ☐ Other (specify)

☐ Ammonia Stack Concentration: Ammonia CEMS Model

Ammonia CEMS Make

SECTION C: APPLICANT CERTIFICATION STATEMENT

I hereby certify that all information contained herein and information submitted with this application is true and correct.

SIGNATURE OF PREPARER:	TITLE OF PREPARER: Consultant	PREPARER'S TELEPHONE NUMBER: (805) 569-6555 PREPARER'S E-MAIL ADDRESS: darvin@atmosphericdynamic
CONTACT PERSON FOR INFORMATION ON THIS EQUIPMENT: John Shao E-MAIL ADDRESS: john.shao@bp.com	CONTACT PERSON'S TELEPHONE NUMBER: (310) 847-5652 FAX NUMBER: (310) 847-5780	DATE SIGNED: 11-5-09

CONFIDENTIAL INFORMATION

Under the California Public Records Act, all information in your permit application will be considered a matter of public record and may be disclosed to a third party. If you wish to keep certain items as confidential, please complete the following steps:

(a) Make a copy of any page containing confidential information blanked out. Label this page "public copy."
(b) Label the original page "confidential." Circle all confidential items on the page.
(c) Prepare a written justification for the confidentiality of each confidential item. Append this to the confidential copy.

Serial Number

Question 3 Support Data

5.2.1.1 Criteria Pollutant Emissions

Tables 5.2-4, 5.2-5, 5.2-6, and 5.2-7 present data on the criteria pollutant emissions expected from the facility equipment and systems under normal operating scenarios. The maximum hourly emissions are based on either Case E-3 (36 degree F day with maximum duct firing) or are based on cold start maximum hourly emission rate. A cold start is defined as a three hour event with the turbine in BACT compliance during hour three. The worst case day is defined at two cold starts (initial cold start failure then a restart for a total of six hours) plus 18 hours of full load operation (Case E-3). The worst-case day for VOC, SO_2, and $PM_{10/2.5}$ is based on 24-hours of full load operation (Case E-3).

Table 5.2-4
Combustion Turbine/HRSG Emissions for the Project
(Steady State Operation-Controlled)

Pollutant	Emission Factor and Units	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)
NO_x	2.0 ppmvd	11.94	286.6	39.9
CO	3.0 ppmvd	10.91	261.8	48.96
VOC	2.0 ppmvd	4.16	99.8	18.2
SOx	<=0.00285 lbs/mmBtu	6.84	164.2	29.9
$PM_{10/2.5}$	<=0.00661 lbs/mmBtu	10.0[1]	240.0	43.8
NH_3	5.0 ppmvd	11.05	265.2	48.4

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
CO = carbon monoxide (proposed 3.0 ppm 1-hour and 2.0 ppm 3-hour)
CTG = combustion turbine generator
lbs/hr = pounds per hour
lbs/mmBtu = pounds per million British thermal units
NH_3 = ammonia
NO_x = nitrogen oxide
$PM_{2.5}$ = sub 2.5-micron particulate matter
PM_{10} = sub 10-micron particulate matter
ppmvd = parts per million, volumetric dry (each of the values in this table has been corrected to 15% O_2)
SO_x = sulfur oxide
VOC = volatile organic compound
Case E-3, 36 Deg F/36% RH, maximum firing CTG and DB.
Non-startup or shutdown emissions for hourly and daily emissions. Annual emissions include startup/shutdown.
Cooling Tower PM_{10} equals 0.33 lb/hr, 7.92 lbs/day, and 1.45 tons per
Annual NH_3 emissions based on 11.05 lbs/hr.
[1] Net project increase of particulate matter (TSP, $PM_{10/2.5}$) is zero and will be capped under existing limit of 1,244 lbs/day

Table 5.2-5
Combustion Turbine Startup and Shutdown Emissions

Parameter/Mode	Cold Startup	Warm Startup	Shutdown
NO_x, lbs/event	211.24	21.32	12.85
CO, lbs/event	300.65	58.72	57.60

Table 5.2-5
Combustion Turbine Startup and Shutdown Emissions

Parameter/Mode	Cold Startup	Warm Startup	Shutdown
VOC, lbs/event	9.95	2.61	4.11
PM_{10}, lbs/event	30.0	7.16	9.34
SO_x, lbs/event	20.52	3.18	5.95
Event Time, minutes (hours)	180 minutes (3 hours)	60 minutes (1 hour)	60 minutes (1 hour)
Number of Events/Year	4	12	16

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
CO = carbon monoxide
lbs = pounds
NO_x = nitrogen oxide
PM_{10} = sub 10-micron particulate matter
SO_x = sulfur dioxide
VOC = volatile organic compound
Turbine startups on natural gas only. During the 3-hour cold start, BACT level emissions are expected during the transition from hour two to hour three. DLN combustors operational at 50% turbine load. Warm start event assumes 26 minutes at full load with maximum duct burner operation. Shutdown event assumes that turbine is operating at full load with maximum duct burner for 52 minutes prior to shutdown.

Table 5.2-6
Combustion Turbine/HRSG Emissions for the Project (Including Base Load, Cold and Warm Startup and Shutdown, Whichever is Greater)

Pollutant	Emission Factor	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)
NO_x	N/A	175.0	637.40	39.9
CO	N/A	210.0	797.59	48.96
VOCs	N/A	4.20	99.84	18.2
SOx	N/A	6.84	164.16	29.95
$PM_{10/2.5}$	N/A	10.0[1]	240[1]	43.8[1]

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
NO_x = nitrogen oxide
CO = carbon monoxide
VOCs = volatile organic compounds
SO_x = sulfur oxide
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter
See Appendix I, Air Quality Data, for detailed emissions and operational data.
Annual emissions assume 8,720 hours with duct firing plus four cold starts (12 hours), 12 warm starts (12 hour), and 16 shutdowns (16 hours) per year.
[1] Net project increase of particulate matter (TSP, $PM_{10/2.5}$) is zero and will be capped under existing limit of 1,244 lbs/day

Table 5.2-7
Cooling Tower Emissions for the Project (Two Cells)

Pollutant	TDS, mg/L	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)
$PM_{10/2.5}$	3575*	0.33	7.92	1.45

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2008.
Notes:
*The TDS presented in the Air Section is greater than the TDS presented in the Water Section in order to be conservative
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter
Drift fraction – 0.001 percent
The existing cooling tower emissions (seven cells) will be reduced from 1.745 lb/hr down to 1.163 lb/hr through the introduction of 0.001 percent drift eliminators.
Emissions are from the new cooling tower cells only, assuming operational time of 24 hr/day and 8760 hr/year.

Table 5.2-8, Summary of Facility Emissions for the Project, presents a summary of the total proposed facility operational emissions.

Table 5.2-8
Summary of Facility Emissions for the Project

Pollutant	lbs/hr	lbs/day	tons/year
NO_x	11.94	637.40	39.9
CO	10.91	797.59	48.96
VOCs	4.16	99.84	18.2
SO_x	6.84	164.16	29.95
TSP	5.0[1]	120.0[1]	21.9[1]
$PM_{10}/_{2.5}$	10.0[1]	240.0[1]	43.8[1]
NH_3	11.05	265.2	48.4

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
CO = carbon monoxide
NH_3 = ammonia
NO_x = nitrogen oxide
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter
SO_x = sulfur oxide
TSP = total suspended particulate
VOCs = volatile organic compounds
Including startup and shutdown emissions, and cooling tower PM_{10}.
[*] TSP filterable portion as referenced in appendix S of 40 CFR part 51.
[1] Net project increase of particulate matter (TSP, $PM_{10/2.5}$) is zero and will be capped under existing limit of 1,244 lbs/day.

Table 5.2-9, Emissions Comparison of the Current Facility to the Project (Tons/Year) compares the proposed potential to emit for the new Project to the inventoried actual emissions for the current facility.

Table 5.2-9
Emissions Comparison of the Current Facility to the Project (Tons/Year)

Pollutant	Refinery Site[1] Actuals	Project Increase, PTE	Total*
NO_x	713.4	39.9	753.3
CO	432.1	48.96	481.06
VOCs	580.1	18.2	598.3.00
SO_x	1221.3	29.95	1,2451.3
PM_{10}	308	45.2[2]	353.2
$PM_{2.5}$	289.9	45.2[2]	753.3

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009. CARB Emissions Inventory Database, 8/2008, Facility Detail Risk Selection, 2005 data.

Notes:

*Calculated emissions increases and decreases.

CO = carbon monoxide
NO_x = nitrogen oxide
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter
SO_x = sulfur oxide
VOCs = volatile organic compounds

[1] Source: CARB Emissions Inventory Database, 8/2008, Facility Detail Risk Selection-2005 data.

[2] Actual $PM_{10/2.5}$ emissions will be capped under existing SCAQMD daily permit limit of 1,244 lbs/day. See Section 5.2.1.1.

A VOC service component listing for the natural gas and refinery gas fuel systems is presented in Appendix I-A. These components are similar to those listed in the current facility permit (#131003) as subject to Condition H23.3, which requires compliance with Rule 1173 and 40 CFR 60, subpart GGG. Fugitive VOC emissions from the refinery gas portions of the listing are insignificant.

Question 5 Support Data

BP Carson Refinery
Carson, CA

FUGITIVE COMPONENT COUNTS AND VOC EMISSIONS
BP Watson Cogen Fifth Train

Component Type		Service	Total Existing Components	Number of Components Removed	Number of Components Added	Net Number of Components Added	Final Component Count	Emission Factor (lb/yr/ component)	Net Change in Annual VOC Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	0	0	535	**535**	535	0	0
	AQMD Approved I&M Program	Fuel & Natural Gas	0	0	0	**0**	0	12	0
		Gas Vapor	0	0	42	**42**	42	23	966
		Light Liquid	0	0	13	**13**	13	19	247
		Heavy Liquid	0	0	4	**4**	4	3	12
Pumps	Sealless Type	Light Liquid	0	0	0	**0**	0	0	0
	Double Mechanical Seals or Equivalent	Light Liquid	0	0	1	**1**	1	104	104
	Single Mechanical Seal	Heavy Liquid	0	0	1	**1**	1	80	80
Compressor		Gas/Vapor	0	0	1	**1**	1	514	514
Flanges		All	0	0	2153	**2153**	2153	1.5	3229
Pressure Relief Valves		All	0	0	8	**8**	8	0	0
Process Drains		All	0	0	169	**169**	169	80	13520
								Total lbs/year:	**18672**
								Total lbs/day:	**51.16**

Notes:

(1) Light liquid and gas/liquid streams: Liquid or gas/liquid stream with a vapor pressure greater than that of kerosene (>0.1 psia @ 100 deg. F or 689 Pa @ 38 deg.C), based on the most volatile class of liquid at >20% by volume.

(2) The non-bellows seal valves (BSV) include valves in instrumentation service, control valve, and drains that are exempt from BSV requirements.

(3) This is a final count. No margin was added.

Flange Count Basis:

a. Flow Orifices = 2 flanges
b. Flanged Valve = 2 flanges; 3 with spectacle blind
c. All valves < or = 1" are socket welded installations - no flanges

Question 6 Support Data

GE 7EA
Detailed Calculations for Maximum Hourly, Daily and Annual Criteria Pollutant Emissions
Updated 3/1/09

Maximum Hourly, Daily and Annual Emissions	Base Load max. hour	Base Load hrs/day	Base Load hrs/yr	Cold Start hrs/day	Cold Start hrs/yr	Warm Start hrs/day	Warm Start hrs/yr	NOx **Base Load** lb/hr	NOx **Cold Start** lb/hr	NOx **Warm** Start lb/hr	SO2 Base lb/hr	CO **Base Load** lb/hr	CO **Cold Start** lb/hr	CO **Warm Start** lb/hr
Turbine with DB/max firing	1	18	8720	6	12	0	12	9.000	175.000	21.324	6.840	10.905	210.000	58.721
Cooling tower	1	24	8760	0	0	0	0	0	0	0	0	0	0	0

Maximum Hourly, Daily and Annual Emissions	VOC Base Load lb/hr	VOC Cold Start lb/hr	VOC Warm Start lb/hr	PM10/PM2.5 PM10 lb/hr	Shutdown hrs/yr	NOx Shutdown lb/hr	CO Shutdown lb/hr	VOC Shutdown lb/hr	PM10/PM2.5 Shutdown lb/hr	SO2 Shutdown lb/hr	NOx Cold Startup lb/event	CO Cold Startup lb/event	VOC Cold Startup lb/event
Turbine with DB/max firing	4.160	4.200	2.613	10.000	16	12.848	57.601	4.105	9.340	5.948	211.240	300.650	9.950
Cooling tower	0.0	0.0	0.0	0.33	0	0	0	0	0	0	0	0	0

	NOx **Max** lb/hr	NOx **Max** lb/day	NOx **Total** tpy	SO2 **Max** lb/hr	SO2 **Max** lb/day	SO2 **Total** tpy	CO **Max** lb/hr	CO **Max** lb/day	CO **Total** tpy	VOC **Max** lb/hr	VOC **Max** lb/day	VOC **Total** tpy	PM10/PM2.5 **Max** lb/hr	PM10/PM2.5 **Max** lb/day	PM10/PM2.5 **Total** tpy
Turbine with DB/max firing	175.00	584.48	39.89	6.84	164.16	29.95	210.00	797.59	48.96	4.16	99.84	18.21	10.00	240.00	43.79
Cooling tower	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.33**	**7.92**	**1.45**
Total	**175.00**	**584.48**	**39.89**	**6.84**	**164.16**	**29.95**	**210.00**	**797.59**	**48.96**	**4.16**	**99.84**	**18.21**	**10.33**	**247.92**	**45.24**
	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy

Assumptions:

Worst case day based on one cold start.
Emissions data based on 36 degree F with 100% load and full duct firing
Annual NOx based on annual average temperature and average duct firing
Turbine BACT will be:

NOx	2.0 ppm (1-hour)
CO	3 ppm (1-hour)
VOC	2.0 ppm
PM10/2.5	Exclusive use of gaseous fuels and limited to 10 lb/hr
SO2	Exclusive use of gaseous fuels at 0.75 gr/100 scf and 40 ppm on RG
NH3	5 ppm

Cooling tower based on 0.001% drift eliminator efficiency with nitrified water TDS 3575 mg/l
Cold Start = 4 times per year at 3 hours each, worst case day is two cold starts not exceeding 6 hours
Worst case day = two cold starts (6 hours) + 18 hours full duct firing
Cold Start Assumptions:
- Hour 1 less than 50% load with max Nox at 175 lb/hr, CO at 210 lb/hr and VOC at 4.2 lb/hr
- Hour 2 approaches and meets 50 % load with Nox at 34.3 lb/hr, CO at 76.11 lb/hr, and VOC **at 1.59 lb/hr (Kiewitt)**
- Hour 3 Full load with duct firing and compliance with BACT

Worst case day for VOC = 24 hours with full duct firing

South Coast AQMD Monthly Emissions Calculations (lbs)

		lbs/hr	lbs/day	31 day lbs/month	30 day avg lbs/month	Offsets Req'd lbs/month	Offsets Req'd lb-day	Annual TPY
Turbine 1	NOx	9	584.48	7093.5	6864.7	0.0	0	39.89
	CO	10.905	797.59	8801.303	8517.4	0.0	0	48.96
	VOC	4.16	99.84	3092.483	2992.7	3591.3	119.7	18.21
	PM10/PM2.5	10	240.00	7443.884	7203.8	8644.5	288.2	43.77
	SOx	5.77	164.16	5090.359	4926.2	0.0	0	29.93
	NH3	11.05	265.20	8232.25	7966.7	0.0	0	48.40
Fugitives	VOC	2.132	51.17	1586.208	1535.0	1842.0	61.4	9.34

	NOx	CO	VOC	PM10/PM2.5	SOx
Max Month Avg Daily Emissions (lb-day) (adjusted for the ERC ratio)	N/A	N/A	181.1	288.2	N/A
Total Annual Emissions (tons):	39.9	49.0	18.2	43.8	29.9
	RTCs				RTCs

Monthly Operations Data

Max Month = 31 days

Base		Annual	Max Month
	Hours	8720	736
	Startups	16	3
	Shutdowns	16	2
	Total	8760	744

RTCs for NOx and SOx based on a 1:1 ratio.

ERC ratio for PM10/PM2.5 and VOC is 1.2:1

	Normal lbs/hr	Cold Startup lb/event	Warm Startup lb/event
NOx	9	211.24	21.324
CO	10.905	300.65	58.721
VOC	4.16	9.95	2.613
PM10/PM2.5	10	30	5.21
SOx	6.84	20.52	3.18
NH3	11.05	33.15	11.05

Question 7 Support Data

5.2.1.1 Criteria Pollutant Emissions

Tables 5.2-4, 5.2-5, 5.2-6, and 5.2-7 present data on the criteria pollutant emissions expected from the facility equipment and systems under normal operating scenarios. The maximum hourly emissions are based on either Case E-3 (36 degree F day with maximum duct firing) or are based on cold start maximum hourly emission rate. A cold start is defined as a three hour event with the turbine in BACT compliance during hour three. The worst case day is defined at two cold starts (initial cold start failure then a restart for a total of six hours) plus 18 hours of full load operation (Case E-3). The worst-case day for VOC, SO_2, and $PM_{10/2.5}$ is based on 24-hours of full load operation (Case E-3).

Table 5.2-4
Combustion Turbine/HRSG Emissions for the Project
(Steady State Operation-Controlled)

Pollutant	Emission Factor and Units	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)
NO_x	2.0 ppmvd	11.94	286.6	39.9
CO	3.0 ppmvd	10.91	261.8	48.96
VOC	2.0 ppmvd	4.16	99.8	18.2
SOx	<=0.00285 lbs/mmBtu	6.84	164.2	29.9
$PM_{10/2.5}$	<=0.00661 lbs/mmBtu	10.0[1]	240.0	43.8
NH_3	5.0 ppmvd	11.05	265.2	48.4

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
CO = carbon monoxide (proposed 3.0 ppm 1-hour and 2.0 ppm 3-hour)
CTG = combustion turbine generator
lbs/hr = pounds per hour
lbs/mmBtu = pounds per million British thermal units
NH_3 = ammonia
NO_x = nitrogen oxide
$PM_{2.5}$ = sub 2.5-micron particulate matter
PM_{10} = sub 10-micron particulate matter
ppmvd = parts per million, volumetric dry (each of the values in this table has been corrected to 15% O_2)
SO_x = sulfur oxide
VOC = volatile organic compound
Case E-3, 36 Deg F/36% RH, maximum firing CTG and DB.
Non-startup or shutdown emissions for hourly and daily emissions. Annual emissions include startup/shutdown.
Cooling Tower PM_{10} equals 0.33 lb/hr, 7.92 lbs/day, and 1.45 tons per
Annual NH_3 emissions based on 11.05 lbs/hr.
[1] Net project increase of particulate matter (TSP, $PM_{10/2.5}$) is zero and will be capped under existing limit of 1,244 lbs/day

Table 5.2-5
Combustion Turbine Startup and Shutdown Emissions

Parameter/Mode	Cold Startup	Warm Startup	Shutdown
NO_x, lbs/event	211.24	21.32	12.85
CO, lbs/event	300.65	58.72	57.60

Table 5.2-5
Combustion Turbine Startup and Shutdown Emissions

Parameter/Mode	Cold Startup	Warm Startup	Shutdown
VOC, lbs/event	9.95	2.61	4.11
PM_{10}, lbs/event	30.0	7.16	9.34
SO_x, lbs/event	20.52	3.18	5.95
Event Time, minutes (hours)	180 minutes (3 hours)	60 minutes (1 hour)	60 minutes (1 hour)
Number of Events/Year	4	12	16

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
CO = carbon monoxide
lbs = pounds
NO_x = nitrogen oxide
PM_{10} = sub 10-micron particulate matter
SO_x = sulfur dioxide
VOC = volatile organic compound

Turbine startups on natural gas only. During the 3-hour cold start, BACT level emissions are expected during the transition from hour two to hour three. DLN combustors operational at 50% turbine load. Warm start event assumes 26 minutes at full load with maximum duct burner operation. Shutdown event assumes that turbine is operating at full load with maximum duct burner for 52 minutes prior to shutdown.

Table 5.2-6
Combustion Turbine/HRSG Emissions for the Project (Including Base Load, Cold and Warm Startup and Shutdown, Whichever is Greater)

Pollutant	Emission Factor	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)
NO_x	N/A	175.0	637.40	39.9
CO	N/A	210.0	797.59	48.96
VOCs	N/A	4.20	99.84	18.2
SOx	N/A	6.84	164.16	29.95
$PM_{10/2.5}$	N/A	10.0[1]	240[1]	43.8[1]

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
NO_x = nitrogen oxide
CO = carbon monoxide
VOCs = volatile organic compounds
SO_x = sulfur oxide
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter

See Appendix I, Air Quality Data, for detailed emissions and operational data.

Annual emissions assume 8,720 hours with duct firing plus four cold starts (12 hours), 12 warm starts (12 hour), and 16 shutdowns (16 hours) per year.

[1] Net project increase of particulate matter (TSP, $PM_{10/2.5}$) is zero and will be capped under existing limit of 1,244 lbs/day

Table 5.2-7
Cooling Tower Emissions for the Project (Two Cells)

Pollutant	TDS, mg/L	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)
$PM_{10/2.5}$	3575*	0.33	7.92	1.45

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2008.
Notes:
*The TDS presented in the Air Section is greater than the TDS presented in the Water Section in order to be conservative
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter
Drift fraction – 0.001 percent
The existing cooling tower emissions (seven cells) will be reduced from 1.745 lb/hr down to 1.163 lb/hr through the introduction of 0.001 percent drift eliminators.
Emissions are from the new cooling tower cells only, assuming operational time of 24 hr/day and 8760 hr/year.

Table 5.2-8, Summary of Facility Emissions for the Project, presents a summary of the total proposed facility operational emissions.

Table 5.2-8
Summary of Facility Emissions for the Project

Pollutant	lbs/hr	lbs/day	tons/year
NO_x	11.94	637.40	39.9
CO	10.91	797.59	48.96
VOCs	4.16	99.84	18.2
SO_x	6.84	164.16	29.95
TSP	5.0[1]	120.0[1]	21.9[1]
$PM_{10}/_{2.5}$	10.0[1]	240.0[1]	43.8[1]
NH_3	11.05	265.2	48.4

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009.
Notes:
CO = carbon monoxide
NH_3 = ammonia
NO_x = nitrogen oxide
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter
SO_x = sulfur oxide
TSP = total suspended particulate
VOCs = volatile organic compounds
Including startup and shutdown emissions, and cooling tower PM_{10}.
* TSP filterable portion as referenced in appendix S of 40 CFR part 51.
[1] Net project increase of particulate matter (TSP, $PM_{10/2.5}$) is zero and will be capped under existing limit of 1,244 lbs/day.

Table 5.2-9, Emissions Comparison of the Current Facility to the Project (Tons/Year) compares the proposed potential to emit for the new Project to the inventoried actual emissions for the current facility.

Table 5.2-9
Emissions Comparison of the Current Facility to the Project (Tons/Year)

Pollutant	Refinery Site[1] Actuals	Project Increase, PTE	Total*
NO_x	713.4	39.9	753.3
CO	432.1	48.96	481.06
VOCs	580.1	18.2	598.3.00
SO_x	1221.3	29.95	1,2451.3
PM_{10}	308	45.2[2]	353.2
$PM_{2.5}$	289.9	45.2[2]	753.3

Source: Watson Cogeneration Steam and Electric Reliability Project Team, 2009. CARB Emissions Inventory Database, 8/2008, Facility Detail Risk Selection, 2005 data.

Notes:

*Calculated emissions increases and decreases.

CO = carbon monoxide
NO_x = nitrogen oxide
PM_{10} = sub 10-micron particulate matter
$PM_{2.5}$ = sub 2.5-micron particulate matter
SO_x = sulfur oxide
VOCs = volatile organic compounds

[1] Source: CARB Emissions Inventory Database, 8/2008, Facility Detail Risk Selection-2005 data.

[2] Actual $PM_{10/2.5}$ emissions will be capped under existing SCAQMD daily permit limit of 1,244 lbs/day. See Section 5.2.1.1.

A VOC service component listing for the natural gas and refinery gas fuel systems is presented in Appendix I-A. These components are similar to those listed in the current facility permit (#131003) as subject to Condition H23.3, which requires compliance with Rule 1173 and 40 CFR 60, subpart GGG. Fugitive VOC emissions from the refinery gas portions of the listing are insignificant.

Question 8 Support Data

Analysis of BACT/LAER Technologies for NO_x for Watson Expansion Project

State and federal regulatory programs require the implementation of emissions controls for the proposed Watson Cogeneration Expansion Project (WEP). South Coast AQMD rules require that BACT be applied for each individual new emissions unit and pollutant emitting activity at which a net emissions increase would likely occur. Individual BACT analysis and determinations may be performed for each pollutant subject to a NSR/PSD review.

<u>Applicability of BACT Requirements</u>

The project must incorporate controls that are designed to meet Best Available Control Technology (BACT) requirements for attainment pollutants and Lowest Achievable Emission Rate (LAER) requirements for non-attainment pollutants. This section presents the NOx BACT/LAER analyses, with proposed emission controls and limits for the project's new emission units. The emissions unit covered by the BACT/LAER control technology review is the proposed combustion turbine and associated HRSG duct burner.

BACT is defined in the SCAQMD NSR regulations (Regulation 13, Rule 1302) as follows:

BACT means the most stringent emission limitation or control technique which:

(1) has been achieved in practice for such category or class of source; or

(2) is contained in any state implementation plan (SIP) approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or

(3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.

LAER is not defined in the SCAQMD NSR regulations, but it should be noted that the District's definition and implementation of BACT is, for all intent and purpose, LAER.

EPA recommends using a "top-down" approach for determining BACT and LAER. This approach essentially ranks potential control technologies in order of effectiveness and ensures that the best technically and economically feasible option is chosen. As described in EPA's *New Source Review Workshop Manual*, draft, October 1990, the general methodology of this approach is as follows:

- Identify potential control technologies, including combinations of control technologies, for each pollutant subject to NSR-PSD review.
- Evaluate each control technology for technical feasibility; eliminate those determined to be technically infeasible.
- Rank the remaining technically feasible control technologies in order of control effectiveness.
- Assume the highest-ranking technically feasible control represents LAER/BACT, unless it can be shown to result in adverse environmental, energy, or economic impacts. LAER

determinations do not typically include an economic impact evaluation.
- Select BACT/LAER.

EPA and State maintained RACT/BACT/LAER Clearinghouses (RBLCs) are considered as principal references for identifying potential control technologies and emission rates used in past permitting of similar sources. These databases were queried for entries since January 2000 involving combustion turbines and duct burners, cooling towers, and boilers. The emission rates proposed in this permit application apply with and without duct firing. Also, the duct burner and combustion turbine have a common release point and the duct burner cannot operate independent of the turbine, thus, the BACT/LAER analyses are conducted for the combined emission rates of the combustion turbine and duct burner. The emission rates proposed are consistent with the entries in the various State and EPA databases for past (post-2000) BACT/LAER evaluations, especially those for sources with similar MMBtu/hr and MW ratings.

The "top-down" procedure is followed for the BACT/LAER analyses for the pollutants evaluated in this analysis, with a focus on identifying emission limitations or control technologies that are achieved in practice and technically feasible.

The proposed WEP turbine/HRSG BACT as delineated in the AFC and AQMD application is as follows:

• NOx	2 ppm @ 15% O_2	DLN and SCR
• CO	4 ppm @ 15% O_2	CO Catalyst
• VOC	2 ppm @ 15% O_2	CO Catalyst
• $PM_{10}/PM_{2.5}$	Clean fuels (Natural gas and refinery gas)	
• SOx	Clean fuels (Natural gas and refinery gas)	
• NH_3	5 ppm @ 15% O_2 (ammonia slip)	

The discussion which follows presents the BACT/LAER analyses and proposed NO_x limits and controls for the turbine/HRSG duct burners.

NOx BACT/LAER Analysis for the Combined Cycle Units

<u>Analysis of Control Requirements for Nitrogen Oxides</u>

1. Identify Potential Control Technologies

The baseline NO_x emission rates for this analysis use the GE 7EA guarantee of 9 ppmvd @ 15% O_2 for the combustion turbines and the HRSG duct burners, i.e., turbines with DLN combustors, and HRSGs with low NO_x burners. These emission rates provide a comparison for the evaluation of control effectiveness and feasibility. The maximum degree of control, which results in the lowest NO_x emission rate, is a combination of dry low-NO_x combustors (DLN) for the turbines and low-NO_x burners (LNB) for the duct burners in conjunction with either selective catalytic reduction (SCR) or SCONOx.

The formation of NO_x from the combustion of fossil fuels can be attributed to two basic mechanisms – fuel NO_x and thermal NO_x. Fuel NO_x results from the oxidation of organically bound nitrogen in the fuel during the combustion process, and generally increases with increasing nitrogen content of the fuel. Because natural gas contains only small amounts of nitrogen, little fuel NO_x is formed during combustion. The vast majority of the NO_x produced during the combustion of natural gas is from thermal NO_x, which results from a high-temperature reaction between nitrogen and oxygen in the combustion air. The generation of thermal NO_x is a function of combustion chamber design and the turbine operating parameters, including flame temperature, residence time (i.e., the amount of time the hot gas mixture is exposed to a given flame temperature), combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_x formation is an exponential function of the flame temperature.

The reduction of NO_x emissions can be achieved by combustion controls and post-combustion flue gas treatment. Combustion modifications for turbines include both wet and dry combustion controls. Wet and dry combustion controls act to reduce the formation of NO_x during the combustion process, while post-combustion controls remove NO_x from the exhaust stream after it is generated. Thus, potential NO_x control technologies for the combustion turbines and duct burners include the following:

Wet combustion controls

- Water injection
- Steam injection

Dry combustion controls

- Dry low-NO_x combustor design (with low-NO_x burners for the duct burners)
- Other combustion modifications
- Catalytic combustors (e.g., XONON)

Post-combustion controls

- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Non-selective catalytic reduction (NSCR)
- SCONOx

2. Evaluate Control Technologies for Technical Feasibility

The performance and technical feasibility of each "category" of NO_x controls listed above are discussed separately. Wet and dry combustion modifications as they are applicable to combustion turbines are discussed first (duct burner controls are achieved with the use of low-NO_x burners). A detailed discussion of post-combustion controls, which can control emissions from both the combustion turbines and duct burners, follows.

Wet Combustion Controls – Water and Steam Injection

Injecting water or steam directly into the turbine combustor are common NO_x control techniques for combustion turbines. The principle behind wet injection techniques is to lower the flame temperature in the combustor, which reduces the formation of thermal NO_x. Specifically, water or steam is injected into the primary combustion chamber to provide a heat sink that lowers the peak flame temperature of combustion. Because water acts as a better heat sink than steam (due to temperature and latent heat of vaporization), more steam is required to achieve an equivalent level of NO_x reduction. The injected water or steam exits the turbine as part of the exhaust.

The performance of wet controls is primarily dependent on the water- or steam-to-fuel ratio, with NO_x emissions decreasing as the water- or steam-to-fuel ratio increases. Additional factors affecting the level of control are the combustor geometry and the design and location of the injection nozzle(s). In order to maximize NO_x reductions, there must be a homogeneous mixture of water droplets and fuel in the combustor. This homogeneous mixture is only achieved through the proper atomization and injection of the water within the turbine combustor region. Typically, for gas-fired turbines, steam injection can reduce NO_x emissions to levels of 15 to 25 ppmv @ 15% O_2. Emission rates for water injection are higher due to the inability to achieve a homogeneous mix of water and fuel in the combustor and are usually around 25 to 45 ppmv @ 15% O_2.

Although the quenching effect of the water or steam lowers the peak flame temperature and thus reduces NO_x emissions, it can also increase CO and hydrocarbon emissions, decrease combustion efficiency, and increase maintenance requirements. Due to incomplete combustion, CO and hydrocarbon emissions can increase as the water- or steam-to-fuel ratio increases. The reduction in efficiency also can increase with increasing water- or steam-to-fuel ratios and is typically greater for water injection (due to the heat of vaporization). For some turbines, due to the injection of water or steam into the combustor, increased wear and erosion in the hot section of the turbine can result in increased maintenance and downtime.

Water and steam injection have been used on gas-fired turbines in all size ranges for many years. Where both systems are available, steam availability at the site and other economic factors usually determine which system is used. These NO_x control technologies are widely available and are technologically feasible.

Dry Combustion Controls

Dry combustion controls reduce NO_x emissions without wet injection systems. Combustion modifications to reduce NO_x formation include lean combustion, reduced combustor residence time, lean premixed combustion, and two-stage rich/lean combustion. Lean combustion uses additional excess air (greater than stoichiometric air-to-fuel ratio) to cool the flame and thus reduce thermal NO_x formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine hot section. The rate of thermal NO_x formation is reduced because the combustion gases are at higher temperatures for a shorter time. The principle behind lean premixed combustion is to premix the fuel and air prior to combustion in order to provide a homogeneous air/fuel mixture, which acts to reduce the combustion temperatures, and thus thermal NO_x. Rich/lean combustion uses a fuel-rich primary stage, quenching, and then a fuel-lean secondary stage to reduce NO_x formation, however, this type of control is currently not very common.

Currently, the most widely used combustion controls are dry low-NO_x (DLN) combustors, which use lean premixed combustion to reduce the formation of thermal NO_x. Prior to the development of premix based dry-low NO_x combustors, fuel and air were injected separately into the turbine's combustor section where oxygen in the combustion air needed to support the combustion process diffused to the flame front located at the combustor's fuel burner. Simply put, the combustion occurred in a diffusion flame similar to that of a Bunsen burner. The result of this approach was a range of fuel-to-air ratios over which combustion occurred and a corresponding range of flame temperatures. The dry-low NO_X combustion process works to reduce the amount of thermal NO_X that is formed by lowering the overall flame temperature within the turbine combustor by premixing the fuel and air at controlled stoichiometric ratios prior to combustion.

DLN combustion is effective in achieving NO_x emission levels comparable to the levels achieved using wet injection without the need for large volumes of purified water or steam. An increase in CO emissions can result from lower NO_x emission rates (in the range of 9 ppmv). However, negligible increases in CO are associated with controlled NO_x emission rates around 9 ppmv (the level for the proposed turbines before subsequent control). Thus, the increases in CO and VOC emissions that result from wet injection are not a factor with such DLN systems. Several turbine vendors have developed DLN systems for their turbines, therefore this technology is considered technically feasible.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5 MW natural gas-fired turbine in Santa Clara, California. Commercial availability of the technology for a 200 MW GE Frame 7 natural gas-fired turbine was recently announced. The technology has also been announced as commercially available for some models of small turbines (around 10 MW or lower).

The combustor used in the Santa Clara demonstration engine is generally comparable in size to that used in GE Frame 7F engines. The technology has not been announced commercially for the engines proposed for this project, thus a commercial quotation for the use of XONON is not available from the supplier, Catalytica Corporation. No turbine vendor, other than General Electric, has indicated the commercial availability of catalytic combustion systems at the present time. Furthermore, in 2001, GE indicated to the developers of the Pastoria Energy Project in California, that XONON technology for large combustion turbines such as the 7FA, would not be available for another 5-7 years. In the fourth quarter of 2002, Catalytica Corporation announced its first commercial operation of a catalytic combustion system on a 1.4 MW Kawasaki turbine. We conclude, that scale up of the system for turbines such as those proposed for WEP, is still several years into the future. Consequently, catalytic combustion controls are not considered commercially available for this project's turbines and are not discussed further.

Post-Combustion Controls

- Selective Catalytic Reduction (SCR)

The SCR process is a post-combustion control technology in which injected ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. The desired level of NO_X emission reduction is a function of the catalyst volume, ammonia-to-NO_x (NH_3/NO_x) ratio, and temperature (450 F to 850 F typical range dependent upon type of catalyst). For a given catalyst volume, higher NH_3/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in undesired increased levels of unreacted NH_3 (called ammonia slip).

The SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include compounds of arsenic, sulfur, potassium, sodium, and calcium. In applications where natural gas is fired, a catalyst life of 5 to 6 years has been demonstrated.

SCR has been demonstrated effective at numerous installations throughout the United States. Typically, SCR is used in conjunction with other wet or dry NO_x combustion controls (e.g., DLN). Because SCR is a post-combustion control, emissions from both turbines and duct burners can be controlled. SCR requires the consumption of a reagent (ammonia or urea) and requires periodic catalyst replacement. Achieved levels of NO_x control equal to or slightly greater than 90% can be achieved.

- Selective Non-catalytic Reduction (SNCR)

SNCR is another post-combustion technology where NO_x is reduced by injecting ammonia or urea into a high-temperature region, without the influence of a catalyst. The SNCR technology requires gas temperatures in the range of 1200°F to 2000°F. The exhaust temperature for the proposed turbines ranges from 1030°F to 1135°F, which is below the minimum SNCR operating temperature. Thus, some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations. SNCR is most commonly used with boilers, and there are no entries in the RBLC indicating the use of SNCR for turbines. SNCR is considered technologically infeasible for this project due to the temperature considerations. However, even if SNCR were technically feasible, it would not be able to achieve NO_x reductions comparable to SCR.

- Nonselective Catalytic Reduction (NSCR)

NSCR uses a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. Typically, NSCR is used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16%. Consequently, NSCR is not technologically feasible for this project.

- SCONOx

The SCONOx system uses a proprietary potassium carbonate coated oxidation catalyst to remove both NO_X and CO. SCONOx is a relatively new system initially marketed and produced by Goal Line Environmental Technologies that began commercial operation in California at the Federal Plant owned by the Sunlaw Cogeneration Partners in December 1996. Other vendors, such as EmeraChem, are now marketing and supplying the next generation of this technology. According to a press release from December 1999, for gas turbine installations larger than 100 MW, ABB Alstom Power is Goal Line's exclusive licensee for SCONOx.

The combustion turbine at the Federal facility is a GE LM-2500 that is approximately 23 MW in size, roughly one-eighth the size of each of the three combustion turbines proposed for this project. The application of the SCONOx system at the Federal Plant is the second-generation of the technology. The first generation was a pilot unit application that operated for ten months at another nearly identical GE LM-2500 based facility, the Growers facility, also owned by Sunlaw Cogeneration Partners. The SCONOx catalyst used at the pilot facility was transported to the Federal facility when the pilot unit was taken out of service.

Two power plant projects in California proposed by PG&E Generating Company have recently proposed the use of SCONOx for NO_x control, although both projects included switching to SCR as a contingency in their permit applications. The La Paloma Generating Project is a merchant plant that originally proposed using SCONOx on one out of its four turbines, although follow-on decisions were made to apply SCR to all four turbines. The University of California at San Diego cogeneration project is equipped with SCONOx. This turbine is a Solar Titan DLN unit rated at 12.9 MW, and is required to meet a NOx limit of 2.5 ppm @ 15% O_2 on a 3 hour basis. In addition, the City of Redding Electric Department (REU) currently operates an Alstom turbine rated at ~43 MW. This unit is also required to meet a NOx limit of 2.5 ppm @ 15% O_2.

The SCONOx system does not use a reagent such as ammonia but instead utilizes natural gas as the basis for a proprietary catalyst regeneration process. The NO present in the flue gas is reduced in a two-step process. First, NO is oxidized to NO_2 and adsorbed onto the catalyst. For the second step, a regenerative gas is passed across the catalyst periodically. This gas desorbs the NO_2 from the catalyst in a reducing atmosphere of hydrogen (H_2) which results in the formation of N_2 and water (H_2O) as the desorption products. For the regeneration/desorption step to occur there must be no oxygen (O_2) present during this step. The CO present in the flue gas is oxidized to CO_2 as part of the SCONOx process.

In order for the SCONOx technology to work properly, inlet/outlet dampers must continuously isolate a portion of the catalyst blocks for regeneration. The SCONOx potassium carbonate layer has a limited adsorption capability and requires regeneration about once every 15 minutes in normal service. Each regeneration cycle requires approximately 3 to 5 minutes. The regenerative gas is passed through the isolated portion of the catalyst while the remaining catalyst is left open to the flue gas flow. After the isolated portion is regenerated, the next set of dampers must close and isolate the next section of catalyst for regeneration. This cycle is continuously repeated. Assuming a four (4) section catalyst, and regeneration times of 15 minutes per section, results in approximately 35,000 regeneration cycles per year.

At the Federal Plant the regenerative gas is produced from natural gas by processing it through a separate skid mounted processing unit. The resulting regenerative gas is approximately 3 percent nitrogen, 1.5 percent CO_2, and 4 percent H_2, with steam making up the balance. Steam is used to: (1) dilute the regenerative gas hydrogen concentration below the lower explosive level; (2) act as a carrier gas; (3) promote the purging of the catalyst bed of the oxygen containing flue gas; and (4) promote even distribution of the regeneration gas throughout the catalyst bed.

Goal Line has tested several methods for producing regeneration gas, including a one step method where steam, natural gas, and air are reacted at 900°F using an auto-thermal process. This process failed to produce consistent results and was abandoned. Goal Line has stated that in future applications, the regeneration gas will be generated in the HRSG at a temperature of approximately 600 °F. This modified system to produce regeneration gas, and to our knowledge, has not been tested on any commercial applications and as such is not yet demonstrated in practice.

Because the active regenerant gas is hydrogen, the regeneration process must be performed in an atmosphere of low oxygen to prevent dilution of the hydrogen. In practice, the oxygen present in the exhaust gas of combustion turbines is excluded from the catalyst bed by dividing the catalyst bed into a number of individual cells or compartments that are equipped with front and rear dampers that are closed at the beginning of each regeneration cycle. Obtaining a good seal with the dampers is key to: (1) preventing oxygen in the flue gas from disrupting the regeneration process, and (2) evenly distributing the regeneration gases across the catalyst.

Complete regeneration of the SCONOx catalyst system is dependent upon the proper functioning and sealing of these sets of dampers approximately four times each hour. Incomplete regeneration of the catalyst results in decreased system performance which in-turn results in increased NO_X emissions. Based on an article by Goal Line (Campbell et al, February 1997), probably the most important cause of reduced performance in the pilot unit was poor distribution of regeneration gas over the catalyst. As a result, several design changes were incorporated into the system located at the Federal Plant.

The SCONOx catalyst is very susceptible to fouling by very small amounts of sulfur in the flue gas. Sulfur causes the catalyst to loose activity. The impact of sulfur is minimized by a sulfur absorption catalyst, called SCOSOx, located upstream of the SCONOx catalyst. First, the SO_2 is oxidized and absorbed on to the catalyst. The SO_3 is then desorbed from the catalyst as part of the SCONOx regeneration process. The resulting byproduct of the regeneration is either H_2S (for systems located in the HRSG where the flue gas temperature is below 450 °F at the catalyst) or SO_2 (for systems located in the HRSG where the flue gas temperature is above 450 °F). This will be a very important factor in the application of this technology to WEP as the turbines fire a mixture of natural gas with refinery gas. Refinery gas BACT for sulfur is presently at a level of 32 ppm, which is approximately 8 to 10 times higher than natural gas sulfur content in pipeline grade (PUC quality) gas.

In the case where H_2S is formed, it is converted back to SO_2 using an additional subsystem and directed into the exhaust downstream of the catalyst. In the case where SO_2 is the byproduct, it is directed into the turbine exhaust downstream of the catalyst. For a new construction project, the system would be placed in the HRSG at a point where SO_2 would be the primary product of the SCOSOx system.

According to Goal Line/ABB, the catalyst requires periodic washing at least annually. The "washing" consists of removing the catalyst modules from the unit and submerging each module in a vessel containing potassium carbonate. Thus, the adsorbent portion of the SCONOx process must be revitalized or replaced at least annually. For units the size of the proposed turbines, total required "wash" time could be on the order of seven (7) days per turbine per wash cycle (including the time to allow safe entry to the HRSG). There are three options available for carrying out this washing:

- To shut down the unit for approximately one week to clean the catalyst. Shut down includes a two-day cooling period prior to personnel entering the HRSG. Unbuttoning and entry into the HRSG. Dismantling of the catalyst support structure to allow the catalyst to be removed. Removal and dipping of the catalyst and then placement back into the HRSG. The actual logistics and design requirements of accomplishing this task on a unit the sizes of the proposed units are not yet known. In addition, this approach has the disadvantage of eliminating the ability to produce power during the outage.
- Removal of the unit while on-line and replacement with clean catalyst while the other catalyst is washed. This approach is impractical in light of the need to assure that all damper seals maintain 100% integrity during the removal. The logistics associated with performing this operation on an application with units the size of the proposed units is also several fold more complicated because of the need to maintain tight damper seals where one side is at operating temperature and the other is at ambient in order to allow worker access. Several safety issues would also have to be overcome. This approach also requires that a spare catalyst set be purchased and stored. Thus, additional storage facilities would also be required.
- Bring the catalyst off-line only long enough to permit removal of the used catalyst and replacement with a spare catalyst set. The removed catalyst is then washed and prepared for placement back in service at the next wash outage.

Any of the above operations will require several days to shutdown and cool the HRSG and SCOSOx/SCONOx sections to the point that the catalyst can be handled safely. Then each catalyst section will have to be removed, washed, dried, and put back in the HRSG before the units can startup again.

Commercially quoted NO_x emission rates for the SCONOx system range from 2.0 ppm on a 3-hour average basis, representing a 78% reduction, to 1.0 ppm with no averaging period specified (96% reduction). Recent system quotes from ABB Alstom Power for a GT26 turbine (rated at 274 MW) indicated a control efficiency ranging from 75% to 80%, i.e., NO_x ppm reductions from 20-25 ppm to 5 ppm. Because it has only been applied at two relatively small combustion turbine facilities, there are several long-term operational concerns that exist with the SCONOx system. Although technical concerns exist, the SCONOx system will be considered technologically feasible for the purposes of this analysis. Thus, based on the information in this section, the following NO_x control technologies are technologically feasible for the proposed project:

- Water injection
- Steam injection
- Dry low-NO_x combustors (low-NO_x burners for the duct burners)
- Selective Catalytic Reduction (SCR)
- SCONOx

3. Rank Technically Feasible Control Technologies by Control Effectiveness

The technically feasible control technologies listed above are ranked by NO_x control effectiveness in the traditional "top-down" format in Table 1.

Table 1 NO_x Control Technologies Ranked by Effectiveness

NO_x Control Alternative	Available	Technically Feasible	NO_x Emissions (@ 15% O_2)	Environmental Impact	Energy Impacts
Selective Catalytic Reduction[a]	Yes	Yes	80-90% reduction 2 – 2.5 ppm	Ammonia slip	Decreased Efficiency
SCONOx	Yes[b]	Yes[c]	75-90% reduction 2 – 2.5 ppm	Reduced CO; potential reduction in VOC	Decreased Efficiency
Dry Low-NO_x Combustors	Yes	Yes	9-25 ppm	Reduced CO/VOC	Increased Efficiency
Steam Injection	Yes	Yes	15 – 25 ppm	Increased CO/VOC	Increased Efficiency
Water Injection	Yes	Yes	25-42 ppm	Increased CO/VOC	Decreased Efficiency

[a] Used in conjunction with wet or dry combustion controls.
[b] The availability of commercial guarantees for utility-scale projects is undetermined.
[c] This technology has been used on two small gas turbines; it has not been demonstrated on utility-scale gas turbines.

4. Evaluate Most Effective Controls

For large gas turbines such as those proposed, water and steam injection have been largely superseded by dry low-NO_x combustors, due to the superior emission control performance and increased efficiency. The proposed project plans to use dry low-NO_x combustors for the combustion turbines, thus no further discussion of water injection, steam injection, or dry low-NO_x combustors is necessary. The duct burners will be equipped with low-NO_x burners, which also represent a high level of emission control performance.

The level of NO_x control for SCR and SCONOx is essentially equivalent. However, the SCONOx process is much more complex both chemically as well as mechanically than the SCR technology. The principal differences between the two technologies are associated with whether the low emission levels proposed have been achieved in practice, the cost-effectiveness in achieving these levels, and secondary environmental impacts.

Table 2 compares the two processes. The SCR catalyst needs to be located in the appropriate section of the HRSG and maintained at the proper temperature. An SCR system also requires ammonia to be injected upstream of the catalyst with good mixing and even distribution. By comparison, the SCONOx process is much more complex in that the catalyst requires continuous regeneration, not just the presence of a reducing agent in the flue gas. Unlike SCR, the regeneration process for SCONOx requires a separate process to generate the regeneration gas and the catalyst must be separated from the flow of hot flue gas, during operation of the unit, for the regeneration process to occur. Thus, the need for the isolation louvers and the ability to frequently remove the SCONOx catalyst for washing.

Each SCONOx catalyst block also has inlet and outlet piping for the regeneration gas. In order to control flow of the regeneration gases, each inlet and outlet pipe has a set of electronically actuated valves. As such, each catalyst section has several actuators and valves that need to properly function and be maintained. In contrast, the SCR ammonia distribution system requires one automatic ammonia flow control valve and a set of manually adjusted valves used as part of the initial tuning of the ammonia injection grid. As a result, relative to the well-demonstrated application of SCR to natural gas-fired sources, the SCONOx processes will have a lower availability and higher operating and maintenance costs for the following reasons:

- The mechanically complex nature of the isolation louvers and positioners;
- The mechanically complex regeneration gas valving system; and,
- The added catalyst regeneration/replacement step (potassium carbonate solution washing).

Table 2 Comparison of SCR and SCONOx Removal Technologies

Process Parameters	SCR	SCONOx	SCONOx
	NO_x Reduction	CO Reduction	NO_x Reduction
Catalyst	Yes	Yes	Yes
Reducing agent & equipment	Yes	No	Yes
Mechanical seals, positioners, and valves	No	Yes	Yes
Catalyst replacement	3-5 years	5 years	1st Row 7-10 years 2nd – 3rd Rows 30 years
Catalyst regeneration	NA	NA	At least annually
By products/ wastes	NH_3 slip	None	Potassium solution

Evaluation of Achieved in Practice

However, the South Coast Air Quality Management District (SCAQMD) has established criteria for determining when control technologies should be considered AIP for the purposes of BACT evaluations. SCAQMD's BACT Scientific Review Committee has recently reviewed a proposed clarification of those criteria, which include the following elements:

Commercial Availability: At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guaranty must be available with the purchase of the control technology, as well as parts and service.

Reliability: All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic equipment must have operated (1) at a minimum of 50% design capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.

Effectiveness: The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests, when possible, or other performance data.

Technology Transfer: BACT is based on what is AIP for a category or class of source. However, USEPA guidelines require that technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: (1) exhaust (backend) controls, and (2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

Achieved in Practice Criteria Evaluation for SCR

SCR has been achieved in practice at a multitude of gas turbine installations throughout the world. This technology has also been demonstrated on large gas turbines through stack testing and continuous emissions monitoring systems (CEMS) at numerous facilities. SCR technology has been making continued advances over the past few years, with many facilities in operation and meeting low NO_x permit limits of 2-3 ppm. There are numerous facilities operating at higher NO_x (2.5–5 ppm) concentrations and experience from these facilities has allowed manufacturers to gain a better understanding of operations to optimize NO_x reduction, sizing of catalyst systems, reagent distribution, and process and control systems.

The following is an evaluation of the proposed AIP criteria as applied to the achievement of extremely low NO_x levels using SCR technology to control both turbine and duct burner emissions.

Commercial Availability: There are numerous manufacturers of SCR catalyst systems and standard commercial guarantees are available. Guaranteed NO_x levels in the range of 2-5 ppm for turbines are commonly available.

Reliability: There are numerous similar installations operating with SCR control systems throughout California and the United States. This technology has been available for years and has demonstrated the ability to meet low NO_x emission rates. There has not been evidence of adverse effects on overall plant operations and reliability from SCR system operating at these levels.

Effectiveness: SCR technology has been demonstrated to achieve NOx levels below 3 ppm (typical permit limits range from 2-2.5 ppm). Due to system design (SCR inlet NO_x levels in excess of those for which the SCR system was designed that caused tripping from pre-mix to diffusion mode), short-term excursions have resulted in NO_x concentrations above 3 ppm. However, these excursions have not been associated with diminished effectiveness of the SCR system. Consequently, as with most control systems designed to reduce emissions to very low levels, the application of SCR should reflect the potential for infrequent NO_x excursions under specified conditions.

Technology Transfer: SCR has been demonstrated on numerous similar installations, and is therefore not a situation of technology transfer.

From the above discussion, SCR technology is considered to be achieved in practice. The technology is capable of achieving NO_x levels of 2-2.5 ppm. The current BACT/LAER guidelines used by EPA Region IX indicate that NO_x levels of 2.0 ppm on a 1 or 3-hour average basis are considered BACT/LAER for utility-scale gas turbines (without supplemental firing). The achievement of NO_x concentrations at these levels, on either a short term or long term basis, have been demonstrated in practice over a wide range of turbine sizes and operational cycles. Thus, the proposed NO_x emission rate for the combustion turbines and duct burners of 2.0 ppm on a 1-3 hour average basis with the application of DLN combustors, DLN burners (HRSG) and SCR meets BACT/LAER.

Achieved in Practice Criteria Evaluation for SCONOx

The SCONOx system has only been operationally applied to relatively small combustion turbine facilities. i.e., less than 50 MW. As a result, there are several long-term operational concerns that exist with the SCONOx system. The SCONOx isolation louvers are moving parts in the flue gas stream that will require more frequent maintenance than any SCR components. In fact, no other combustion turbine systems or boilers have damper systems that require frequent operation from a fully open to a fully closed position.

Louver and damper systems are subject to mechanical and thermal stresses and strains that result from changes in temperatures associated with startup and shutdown as well as normal fluctuations in operating temperatures during load changes or changes in steam demand. These thermal/mechanical stresses result in operating and maintenance problems that are magnified with increases in scale. It should be noted that the change in placement/position of the SCONOx from the Federal facility location where the operating temperature is 320 °F to the Goal Line stated preferred, undemonstrated, location where the operating temperature will be 550 to 650 °F will increase the challenges associated with maintaining good seals during regeneration.

Another issue of concern is long-term catalyst availability and pricing. The SCONOx catalyst is a proprietary catalyst produced and available through only Goal Line/ABB, unlike SCR catalysts that are available through multiple suppliers that guarantee competitive pricing and availability. While Goal Line/ABB guarantees a catalyst life of three years, this catalyst life has not yet been commercially demonstrated over multiple applications, since only a single unit has been operated over that length of time. It is important to note that although SCR catalysts are now well demonstrated, during the first three years of operation on the initial five (5) combustion turbine applications in the U.S. there were numerous catalyst change outs. Also, vendor guarantees are only good for replacement of the catalyst. The guarantee does not:

- Pay for lost revenues associated with downtime;
- Pay for the cost of any penalties resulting from any exceedence of a permit limit;
- Pay for the cost of removing SCONOx and replacing it with an SCR system; and,
- Ensure that the catalyst will be replaced until the system works. Subsequent catalyst replacements are at the vendor's discretion and it is left to the vendor discretion to abandon a particular application at any time.

All of these risks and their associated costs would be borne by the proposed project.

In addition to performance-related concerns about the SCONOx system, there are several specific concerns regarding applying the SCONOx system to this project. Applying the system on a unit that is 2-3 times larger than current full-scale application would require a major redesign of the dampers. The dampers at the Federal Plant are 10 feet wide. The HRSG for this project would be approximately 30-feet wide.

A width that is 3 times greater than that previously demonstrated results in concerns about designing dampers that provide an adequate seal when fully opened and closed during the numerous regeneration cycles required (i.e., as many as 35,000 times per year). This concern is heightened for an application at temperatures greater than those at the Federal Plant. In addition, potential interferences between damper actuators and the regeneration gas injection system would need to be resolved, as well as issues on attaining and maintaining cross flow distribution of regeneration gas across a 30 foot catalyst section.

In an independent evaluation of SCONOx conducted by Stone & Webster, *Independent Technical Review – SCONOx Technology and Design Review*, from February 2000, it is reported that the initial operation of the SCONOx system at the second installation – the Genetics Institute turbine facility in Massachusetts - resulted in a rapid loss of performance due to poor operation of the regeneration system. The problem was traced to mechanical deficiencies, such as seal and gasket leakage, and numerous corrective actions were necessary. Further changes to the overall system included adding an external reformer and adding a sulfur filter to remove sulfur from the gas that feeds the external reformer. Moreover, Stone & Webster reports that a number of damper/seal design changes have been proposed by ABB based on results from testing of the system. Furthermore, the Stone and Webster analysis also reports that "no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because of feasibility of the "scale-up" of the SCONOx system for large turbines has not been demonstrated, we do not consider SCONOx to be a viable control alternative for NOx" (CARE Comments, EAEC PDOC, 2002).

Data presented in the BACT analysis for the Orange Grove Project AFC (TRC Consultants, Appendix 6.2-1) indicates that SCONOx still has much higher capital and operating costs as compared to and SCR/CO Catalyst equipped unit, while NOx limits in the range of 2-2.5 ppm are achievable by both technologies.

Data presented in the FMPA Combustion Turbine BACT Analysis prepared for the Florida DEP (October 2004) indicates that "the application of this technology is currently limited to natural gas combined cycle combustion turbine units under 40 MW".

Data presented in the BACT analysis for the Sierra Pacific Industries Biomass-Fired Cogeneration project (Geomatrix Consultants, May 2007), indicates that a search of BACT applications for SCONOx revealed that the technology had only been applied to small-to-medium sized gas turbines. This is consistent with current data that shows the largest turbine to actually employ and operate a SCONOx system is rated at ~43 MW (Alstom unit).

Additionally, it is noteworthy that the Blue Ridge Environmental Defense League in its comments regarding the proposed Henry County Power, LLC facility (1100 MW gas fired plant) dated March 2002 indicates that SCONOx only guarantees NOx levels down to 2 ppm @ 15% O_2.

Demonstration project results obtained for the City of Redding Alstom turbine indicated the following:

- The SCONOx unit installed on the 43 MW Alstom GTX 100 turbine was a demonstration unit only. The demonstration program lasted three (3) years.
- The unit NOx limit is 2.5 ppm @ 15% O_2. The demonstration project was allowed under the premise that the unit would be required to limit NOx to 2.0 ppm at the end of the program.
- District review of the demonstration program data supplied by the City of Redding electric department resulted in the following conclusions on the part of the Shasta County AQMD.

1. The average NOx concentration during the first three years of operation was 1.24 ppm. The average NOx concentration in June 2004 was 2.0 ppm, and the average NOx concentration in January 2005 was 2.8 ppm.
2. Unit 5 NOx emissions exceeded the District permit limit of 2.5 ppm for 28.02 hours over the first three years of operation, with a majority of this time exempted from District enforcement action per the Excess Emissions rule.
3. Unit 5 NOx emissions exceeded the demonstration limit of 2.0 ppm for 296 hours over the last 2 years.
4. Maintenance and repairs on the existing emission control system began shortly after facility startup and are continuing to the present (6-23-05). The re-design of the emission control device originally centered around the reformer reactor gas production and has currently led to the catalyst and sulfur poisoning of the catalyst.
5. SCONOx catalyst washings have occurred at a frequency several time higher than anticipated during the three years of operation. These additional washings, undertaken for the sole purpose of maintaining NOX emission limits, have resulted in substantial downtime for Unit 5.
6. Load summary data indicate that Unit 5 has been operated at 24 MWs or less for over 60% of total operating hours.
7. "... the District has determined that Redding Power is not able to reliably and continuously operate while maintaining the NOx demonstration limit of 2.0 ppmvd @ 15% O_2. The NOx emission limit in the PTO and the Title V permit shall remain unchanged from the 2.5 ppmvd 1-hour rolling average @ 15% O_2.

Our review of the data submitted by REU to the Shasta AQMD on 6-13-05 on the results of the demonstration program show the following:

- The unit has rarely operated during the last 2 years.
- Approximately 64.5% of operating time is at load levels less than or equal to ~24-25 MWs.
- Approximately 75.2% of operating time is at load levels less than or equal to ~32-34 MWs.
- Maintenance and repairs noted for the period 6/2002 to 3/2005 included such items as; (1) damper seal gasket leakage, (2) steam reformer reactor replacement, (3) steam heater design temperature insufficient for regeneration (required heater installation to raise temperature), (4) regeneration distribution plate design was unsatisfactory (re-design was required), (5) sulfur filter on steam reformer was undersized (required larger filter), (6) regeneration purging required to reduce catalyst poisoning, (7) a second layer of SCOSOx catalyst was required to prevent SCONOx catalyst poisoning, and (8) the SCONOx regeneration gas supply valves were upgraded to Class 6.

We conclude that the less than stellar operation of the SCONOx system on a turbine that rarely operates at loads close to base load may well be indicative of system operational problems upon scale-up to larger turbines which will operate at base load conditions.

The following is an evaluation of the proposed AIP criteria as applied to the achievement of extremely low NO_x levels using SCONOx technology.

Commercial availability: SCONOx is available through only a small number of vendors and has been applied to a very limited number of small sized projects. Due to the lack of information in the public domain, there are still questions regarding whether SCONOx technology is presently available with standard commercial guarantees for NO_x levels as low as 2.0 ppm, with current facilities using SCONOx showing NOx limits at 2.5 ppm. Repeated requests to EmeraChem (Goal Line Environmental Technology SCONOx vendor) for a listing of gas turbine projects rated at greater than 50 MW using SCONOx has produced no data to date. Another concern is whether the guarantee will be passed on by the HRSG vendors. Also, it is questionable that the system will be able to achieve 2-3 ppm controlling both the turbine and duct burner emissions, especially on a system with a large number of duct burners. In addition, the WEP proposed firing of a mixture of refinery gas and natural gas will present catalyst poisoning and reliability issues not confronted by a simple natural gas fired turbine/HRSG unit.

Thus, numerous questions exist regarding the availability of a commercial guarantee for SCONOx. There are also numerous questions regarding scale-up of a SCONOx system to units of the size proposed for this project, consequently, problems associated with installation and operation have to be anticipated. As previously mentioned, even if a commercial guarantee is available, it does not cover the loss of revenue associated with downtime and the potential need to replace the SCONOx system with a SCR system if the required emission level cannot be achieved.

Reliability: Due to the fact that the SCONOx system has not been installed and operated for an extended period of time on a utility-scale turbine, serious questions exist regarding the reliability of the system on such an installation. There have also been numerous design changes since the original SCONOx installation at the Federal plant. As witnessed in the Stone & Webster report, there have been problems at the Genetics Institute facility that have also required redesign. Consequently, the system that would be applied to a utility-scale application would also likely require design changes, thus, the reliability of the $SCONO_x$ system is substantially unknown.

Effectiveness: The analysis contained in Calpine's Metcalf Energy Center AFC demonstrates that the effectiveness of the SCONOx system to meet a 2-3 ppm limit on a consistent basis without exceedences is in question. Also, there have been numerous design changes associated with the SCONOx system and as such it is uncertain as to whether the actual system that would be installed on a larger, utility-scale turbine has been subjected to performance testing. From the available data, if SCONOx technology were to be used to achieve extremely low NO_x levels, it would be necessary to include permit conditions that would allow for the potentially frequent NO_x excursions under certain conditions.

Technology Transfer: SCONOx technology has been found to be capable of achieving extremely low NO_x levels by SCAQMD and EPA (although the data from the Federal facility does not support this conclusion for an extended period of time, without numerous exceedences). The SCONOx system has not been installed on a utility-scale turbine, and serious technical concerns have been enumerated in this application regarding such a scale-up of the technology. While it is not fair to regard this as technology transfer, it is fair to say that SCR has been installed on a large operating fleet of similar installations and is a more demonstrated technology.

In summary, the evaluation concludes that the SCONOx process is not commercially demonstrated on larger, utility-scale turbines and the economic risks to the project versus SCR are considerable. This is because the moderate temperature SCONOx process (post-HRSG location) has not been commercially demonstrated on units the size of the proposed project, and the high temperature SCONOx process (mid-HRSG location) proposed by the developers for large turbines has not been commercially demonstrated on any size unit. The significant technical/economic risks are a result of the following:

- No commercial demonstration of the SCONOx catalyst operation/regeneration at the mid-HRSG location proposed by the developers for large combustion turbine units like the proposed units;
- No commercial demonstration of the regeneration gas system proposed by the developers for large combustion turbine units like the proposed units;
- No commercial demonstration of the technology on large turbines firing refinery gas or a mixture of natural gas and refinery gas;
- No commercial demonstration of a much larger more complex damper system needed to apply the SCONOx technology to very large CT/HRSG systems (concerns here are related to size, complexity, and placement of a damper system into a higher temperature position of the HRSG (i.e., 650 °F versus 350 °F)); and,
- The additional complexity of the SCONOx technology when compared to SCR. This additional complexity will result in lower project availability and could impact revenue generation as well as impacting the steam host operations (BP Carson Refinery).

5. Select LAER/BACT

Based on the analysis presented, either SCR or SCONOx is generally considered capable of achieving NO_x levels of 2.0-2.5 ppm for combustion turbines. However, technical concerns are associated with the use of SCONOx. LAER for NO_x is considered to be the use of either SCR or SCONOx systems in conjunction with dry low-NO_x combustors to achieve NO_x levels for the combustion turbines of 2.0-2.5 ppm on a 1-3 hour average basis. The proposed project will have duct burners in the HRSG (low-NO_x design), consequently, the proposed BACT rate needs to take this supplemental firing into account. Consequently, a NO_x level of 2.0 ppm on a 1 or 3-

hour average basis is proposed, which is consistent with the lowest emission rates contained in the RBLCs, and found in other recent permitting approvals for similar sized power plants. Due to the technical concerns related to the use of SCONOx and the increased cost, the project proposes the use of SCR technology to meet this emission rate. Thus, the proposal is consistent with the LAER requirements for NO_x.

Tables 3 and 4 present the cost-effectiveness analysis. As shown in Table 3, the total annualized costs for SCR (per turbine/HRSG) are $2.62 million (approximately $3400/ton NO_x removed). Table 4 presents the total annualized costs for SCONOx, which are $6.46 million (approximately $8400/ton of NO_x removed). This value is not cost warranted and it is well above the DAQ recent BACT determinations cost values.

Based on these tables, the annual incremental cost of SCONOx is $3.84 million per year per turbine, or over $11.5 million per year for the facility. Consequently, SCONOx is not cost-effective when compared to SCR.

The combined capital cost of the SCR and CO catalyst systems is approximately $5.9 million, while the SCONOx capital cost is approximately $12.88 million. Annual costs for the SCR and CO catalyst systems are estimated at $3.1 million, as compared to the SCONOx annual costs of $6.46 million. The combined control costs for the SCR and CO catalyst systems is approximately $4800/ton, while the control costs for the SCONOx system for both NO_x and CO is estimated at $5800/ton. Table 3 presents a comparison of SCR versus SCONOx system costs.

Table 3 Summary of NO_x BACT Evaluation Results*

Control	Capital Cost	Annualized Cost
SCR	$4,493,300	$2,617,040
SCONOx	$12,880,000	$6,458,406

* All costs are presented on a per gas turbine/HRSG basis

The applicant proposes to use SCR technology to meet a:

NO_x level of 2.0 ppm on a 1-3 hour average basis for the combustion turbines and duct burners with an ammonia slip level of 5 ppm during the steady state unit operation.

This proposal is consistent with BACT/LAER requirements and with emission rates found in numerous RBLC databases, as well recent permitting actions for similar sized power plants.

The cost analysis data presented for the NO_x and CO control systems is based upon the guidance provided by EPA-OAQPS in "*OAQPS Control Cost Manual, 5th Edition, February 1996, EPA 453/B-96-001*". In addition, system specific data derived from the manufacturer or taken from literature sources for similar systems was used to supplement the OAQPS cost analysis procedures. Table 4 delineates a summary of other relevant data used in the cost analyses. Additional references are given on the individual cost tables.

Table 4 Supplemental Economic Cost Factors

Cost Factor	Value
Interest Rate	7% (OMB recommended value)

Control System Life	15 years
Natural Gas Cost	$0.0041/scf
Electricity Cost	$0.0527/kWh
Labor Cost Operator and Maintenance	$41.50/hr

Source: Currant Creek Power Plant Air Application, PacifiCorp-2003, ECT-2003.

Redding Electric SCONOx Data

DOCUMENT #1 (1 PAGE)

March 15, 2005

Russ Bennett, Safety and Environmental Coordinator
Redding Electric Utility
P.O. Box 496071
Redding, CA 96049-6071

Unit 5 Oxides of Nitrogen Demonstration Limit

Dear Mr. Bennett:

Condition C.7 of Redding Power Plant Title V permit #03-TV-02 requires that Redding Power shall install, operate, and maintain the Unit #5 SCONOx system in a manner designed to achieve a Demonstration NOx Limit of 2.0 ppmvd, 1 hour rolling average @ 15% O_2 and in conformance with the SCONOx vendor's procedures. The condition also requires Redding Power to conduct the demonstration program for a three-year period. The three-year period concludes on June 1,2005.

In order for the District to evaluate the feasibility of the demonstration limit, please submit the following Unit #5 information for the period of June 2, 2002, to June 1, 2005:

a. Periods of NOx emissions 1-hour rolling average over 2.5 ppm

b. Periods of NOx emissions 1-hour rolling average over 2.0 ppm

c. Recap of all maintenance and repair performed on the SCONOx system

d. Any upsets or malfunctions to the SCONOx system that were not required to be called in to the District under Rule 3:10

e. Any other information relative to the SCONOx system installation, operation and maintenance during this period including the turbine operating rate

Please submit this information to the District by July 1, 2005. If you have questions regarding this matter, please contact me at 225-5674.

Sincerely,

Ross Bell
Air Quality District Manager

RB/eg

Shasta County

DEPARTMENT OF RESOURCE MANAGEMENT
1855 Placer Street, Redding, CA 96001

Russ Mull, R.E.H.S., A.I.C.P.
Director
Richard D. Barnum
Assistant Director

June 23, 2005

DOCUMENT #3
(2 PAGES)

Russ Bennett
Safety and Environmental Coordinator
Redding Electric Utility
P.O. Box 496071
Redding, CA 96049-6071

Dear Mr. Bennett:

UNIT 5 DEMONSTRATION LIMIT, PTO# 00-PO-39 CONDITION # 26

The Shasta County Air Quality Management District (District) is in receipt of your letter dated June 13, 2005, with the data attached regarding the Unit 5 Oxides of Nitrogen (NOx) Demonstration Limit. This information gathering was a result of District oversight of your demonstration program regarding an NOx limit of 2.0 ppmvd at 15% oxygen as contained in note 1 of Condition 26 of the District-issued permit.

With review of the above information and routine reports submitted to the District, the following findings are made:

1. 11.527 tons of NOx were emitted by Redding Power's Unit 5 during the first three years of operation.

2. The average arithmetic NOx concentration during the first three years of operation was 1.24 ppmvd at 15% oxygen. The average NOx concentration during the month of June 2004, was 2.00 and during the month of January 2005, it was 2.8 ppmvd @15% O2.

3. Unit 5 NOx emissions exceeded the District limit of 2.5 ppmvd @ 15% O2 for 28.02 hours over the last three years of operation. Four minutes of this exceedance time was not exempted by District Rule 3:10, Excess Emissions.

4. Unit 5 NOx emissions exceeded the Demonstration limit of 2.0 ppmvd @ 15% O2 for 296 hours over the last two years.

5. Maintenance and repairs on the existing emission control system began shortly after start up and are continuing to the present. The redesign of the emission control device originally centered around the reformer reactor gas production and has currently led to the catalyst and sulfur poisoning of the catalyst. Additional SCOSOx catalyst was added to the control device during the April 2005, outage.

6. SCONOx catalyst washings have occurred at a frequency several times higher than anticipated during the three years of operation. These additional washings, for the sole purpose of maintaining NOx emission limits, have resulted in substantial downtime for Unit 5.

7. Load summary data indicate that Unit 5 has been operated at 24 megawatts or less for over 60% of total operating hours. Unit 5 is designed for 43 megawatts.

Based on the above findings, the District has determined that Redding Power is not able to reliably and continuously operate while maintaining the NOx demonstration limit of 2.0 ppmvd @ 15% O2. The NOx emission limit in the Permit to Operate and the Title V permit shall remain unchanged from the 2.5 ppmvd 1-hour rolling average @ 15% O2. Note 1 on condition 26 of District issued Permit to Operate #00-PO-39 and note 2 on Condition C7 of Title V Permit # 03-TV-02 that refer to the NOx demonstration limit will be removed as these permits are renewed.

If you have any questions regarding this determination please contact me at 225-5674.

Sincerely,

Ross Bell

Ross Bell
Air Quality District Manager

RB/dd

REU
REDDING
ELECTRIC
UTILITY
CITY OF REDDING
Smart Service... Bright Ideas!

DOCUMENT #2
(24 PAGES)

June 13, 2005

CODE: E-020-010-000
E-120-150-000
E-120-150-650

DEPARTMENT OF
RESOURCE MANAGEMENT
RECEIVED

JUN 13 2005

PLANNING/BUILDING
DIVISIONS

RECEIVED
JUN 14 2005
SHASTA COUNTY AQMD

Mr. Ross Bell, Air Division Manager
Shasta County Dept. of Resource Management
Shasta Air Quality Management District
1855 Placer Street, Suite 101
Redding CA 96001

Re: Unit 5 Oxides of Nitrogen Demonstration Limit

Enclosed are Attachments A through E to provide the information you requested in your 3/15/05 letter.

Attachment A is summary of the Unit 5 periods of NOx emissions one-hour rolling average over 2.5 ppm compiled from the monthly reports submitted to your office.

Attachment B is a summary of the Unit 5 periods of NOx emissions one-hour rolling average over 2.00 ppm. Our Data Acquisition and Handling System (DAHS) is not programmed to calculate or record these periods. The periods reported were obtained by extracting the raw minute data from the DAHS. The data was then corrected to 15 percent O2 and evaluated month to month with spreadsheet software to calculate the periods of excess emissions. Only data with normal NOx CEMS monitoring codes were used in the 60-minute rolling average. Data prior to May 6, 2003 was not readily available and not included in the evaluation. The periods reported may have occurred during the start up and shut down of the unit.

Attachment C is a recap, provided by Alstom, of all maintenance and repairs performed on the SCONOX system.

Attachment D is a summary of upsets or malfunctions to the SCONOX system that were not covered in Attachment C or reported to your office.

Attachment E is a summary of additional information relative to the SCONOX system installation, operation, and maintenance not presented in Attachments A through D.

If you have any questions, please call.

Sincerely,

Russ Bennett

Russ Bennett
Safety & Environmental
Compliance Coordinator

C: Jeff Adkins, Sierra Research

777 Cypress Avenue • P.O. Box 496071 • Redding, California 96049-6071
530.339.7300 • Fax 530.339.7389 • reddingelectricutility.com
Working Together to Improve Our Community

Response to 3/15/05 Shasta County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"

Periods of NOx emissions 1-hour rolling average over 2.5 ppm (15% O2)

6/18/02 from 11:34 am to 1:15 pm (Reported, however, occurred during start up).

No periods of excess emissions in July 2002.

8/12/02 starting at 4:29 pm and lasting for 1 hour, 53 minutes.
8/13/02 starting at 4:10 pm and lasting for 42 minutes.
8/15/02 starting at 3:14 pm and lasting for 18 minutes.
8/16/02 starting at 5:28 pm and lasting for 1 hour, 40 minutes.

9/4/02 starting at 10:30 am and lasting for 21 minutes.
9/18/02 starting at 12:52 pm and lasting for 15 minutes.

10/1/02 starting at 7:57 am and lasting for 39 minutes.
10/1/02 starting at 9:11 am and lasting for 1 hour, 24 minutes.
10/2/02 starting at 7:44 am and lasting for 5 hours, 50 minutes.
10/2/02 starting at 1:43 pm and lasting for 6 minutes.
10/2/02 starting at 4:06 pm and lasting for 1 hour, 5 minutes.
10/11/02 starting at 3:57 pm and lasting for 1 hour, 6 minutes.
10/11/02 starting at 5:03 pm and lasting for 28 minutes.
10/14/02 starting at 5:01 pm and lasting for 10 minutes.
10/14/02 starting at 5:49 pm and lasting for 1 hour, 48 minutes.
10/18/02 starting at 8:04 pm and lasting for 4 minutes.
10/18/02 starting at 9:52 pm and lasting for 25 minutes.

No periods of excess emissions from November 2002 to February 2003.

3/18/03 from 1:27 am to 1:36 am.
3/18/03 from 1:52 am to 1:59 am.
3/18/03 from 8:02 am to 8:07 am.
3/18/03 from 8:42 am to 8:53 am.

No periods of excess emissions from April 2003 to May 2003.

6/9/03 starting at 10:09 am and lasting for 3 hours, 14 minutes.
6/26/03 starting at 5:13 pm and lasting for 5 minutes.
6/26/03 starting at 5:19 pm and lasting for 6 minutes.

No periods of excess emissions from July 2003 to August 2003.

9/14/03 starting at 12:05 pm and lasting for 52 minutes.

Response to 3/15/05 Shasta County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment A, Page 2 of 2

10/20/03 from 3:07 pm to 3:25 pm.

No periods of excess emissions from November 2003 to December 2003.

1/3/2004 starting at 5:36 pm and lasting for 46 minutes.

2/20/04 starting at 7:41 am and lasting for 29 minutes.

No periods of excess emissions from March 2004 to June 2004.

7/12/04 starting at 12:56 (Pacific Standard Time) and lasting for 18 minutes.

No periods of excess emissions from August 2004 to October 2004.

11/2/04 starting at 7:34 pm (Pacific Standard Time) and lasting for 10 minutes.

12/1/04 starting at 6:34 pm (Pacific Standard Time) and lasting for 1 minute.
12/1/04 starting at 6:40 pm (Pacific Standard Time) and lasting for 2 minutes.
12/1/04 starting at 6:47 pm (Pacific Standard Time) and lasting for 1 minute.

1/5/05 starting at 10:53 am (Pacific Standard Time) and lasting for 12 minutes.

No periods of excess emissions February 2005.

3/30/05 starting at 4:11 pm (Pacific Standard Time) and lasting for one hour.

No periods of excess emissions from March 2005 to June 1, 2005.

Response to 3/15/05 Shasta County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment A, Page 1 of 2

Periods of NOx emissions 1-hour rolling average over 2.5 ppm (15% O2)

6/18/02 from 11:34 am to 1:15 pm (Reported, however, occurred during start up). start/shut 101

No periods of excess emissions in July 2002.

8/12/02 starting at 4:29 pm and lasting for 1 hour, 53 minutes. start-up 113
~~8/13/02 starting at 4:10 pm and lasting for 42 minutes.~~
8/15/02 starting at 3:14 pm and lasting for 18 minutes. 42
8/16/02 starting at 5:28 pm and lasting for 1 hour, 40 minutes. 18
100

9/4/02 starting at 10:30 am and lasting for 21 minutes. 21
9/18/02 starting at 12:52 pm and lasting for 15 minutes. 15

10/1/02 starting at 7:57 am and lasting for 39 minutes. 39
10/1/02 starting at 9:11 am and lasting for 1 hour, 24 minutes. 6:19 84
10/2/02 starting at 7:44 am and lasting for 5 hours, 50 minutes. 12:09 350
10/2/02 starting at 1:43 pm and lasting for 6 minutes. 12:15 6
10/2/02 starting at 4:06 pm and lasting for 1 hour, 5 minutes. 13:20 65
10/11/02 starting at 3:57 pm and lasting for 1 hour, 6 minutes. 14:26 66
10/11/02 starting at 5:03 pm and lasting for 28 minutes. 14:54 28
10/14/02 starting at 5:01 pm and lasting for 10 minutes. 15:04 10
10/14/02 starting at 5:49 pm and lasting for 1 hour, 48 minutes. 16:52 108
10/18/02 starting at 8:04 pm and lasting for 4 minutes. 16:56 4
10/18/02 starting at 9:52 pm and lasting for 25 minutes. shut down 25

No periods of excess emissions from November 2002 to February 2003.

3/18/03 from 1:27 am to 1:36 am. shut down
3/18/03 from 1:52 am to 1:59 am.
3/18/03 from 8:02 am to 8:07 am.
3/18/03 from 8:42 am to 8:53 am. 32

No periods of excess emissions from April 2003 to May 2003.

6/9/03 starting at 10:09 am and lasting for 3 hours, 14 minutes. 20:10 194
6/26/03 starting at 5:13 pm and lasting for 5 minutes. shut down 5
6/26/03 starting at 5:19 pm and lasting for 6 minutes. 〃 6

No periods of excess emissions from July 2003 to August 2003.

9/14/03 starting at 12:05 pm and lasting for 52 minutes. 21:62 52

Response to 3/15/05 Shasta County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment A, Page 2 of 2

10/20/03 from 3:07 pm to 3:25 pm. Start 18

No periods of excess emissions from November 2003 to December 2003.

1/3/2004 starting at 5:36 pm and lasting for 46 minutes. Start 46

2/20/04 starting at 7:41 am and lasting for 29 minutes. 22:31 29

No periods of excess emissions from March 2004 to June 2004.

7/12/04 starting at 12:56 (Pacific Standard Time) and lasting for 18 minutes. Start 18

No periods of excess emissions from August 2004 to October 2004.

11/2/04 starting at 7:34 pm (Pacific Standard Time) and lasting for 10 minutes. Start 10

12/1/04 starting at 6:34 pm (Pacific Standard Time) and lasting for 1 minute.
12/1/04 starting at 6:40 pm (Pacific Standard Time) and lasting for 2 minutes. 4
12/1/04 starting at 6:47 pm (Pacific Standard Time) and lasting for 1 minute. 22:35

1/5/05 starting at 10:53 am (Pacific Standard Time) and lasting for 12 minutes. 22:47 excusable malfunction 12

No periods of excess emissions February 2005.

3/30/05 starting at 4:11 pm (Pacific Standard Time) and lasting for one hour. Start 60

No periods of excess emissions from March 2005 to June 1, 2005.

168 min

28.02 hrs.

Response to 3/15/05 Shast County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment B, Page 1 of 3
Periods of NOx emissions 1-hour rolling average over 2.00 ppm (15% O2)

Total time over 2.00 ppm 1-hour rolling average (Hours): 296

Start	Stop	Minutes	Start	Stop	Minutes
5/12/03 8:22	5/12/03 11:27	185	9/26/03 10:43	9/26/03 11:26	43
6/9/03 10:00	6/9/03 13:33	315 213	9/26/03 16:02	9/26/03 16:05	3
6/10/03 10:46	6/10/03 11:22	36	9/30/03 11:49	9/30/03 21:03	554
6/10/03 16:26	6/10/03 18:55	149	10/13/03 7:08	10/13/03 8:01	53
6/11/03 10:07	6/11/03 10:55	48	10/15/03 14:57	10/15/03 15:08	11
6/11/03 16:30	6/11/03 16:50	20	10/19/03 11:00	10/19/03 12:03	63
6/12/03 9:38	6/12/03 9:52	14	10/20/03 11:09	10/20/03 15:45	18 start 276
6/12/03 15:05	6/12/03 15:52	47	10/20/03 18:04	10/20/03 18:16	12
6/25/03 15:53	6/25/03 17:30	97	10/24/03 12:04	10/24/03 13:59	115
6/26/03 15:02	6/26/03 18:08	5+6 start 186	11/4/03 9:25	11/4/03 9:30	5
7/1/03 10:50	7/1/03 13:03	133	11/4/03 11:53	11/4/03 11:54	1
7/2/03 9:18	7/2/03 11:26	128	11/4/03 17:42	11/4/03 17:46	4
7/8/03 18:59	7/8/03 19:12	13	11/17/03 7:33	11/17/03 11:16	223
7/10/03 18:12	7/10/03 19:12	60	12/17/03 14:17	12/17/03 15:20	63
7/11/03 19:01	7/11/03 20:15	74	12/17/03 15:34	12/17/03 15:50	16
8/5/03 8:54	8/5/03 8:57	3	12/27/03 5:57	12/27/03 6:15	18
8/5/03 9:28	8/5/03 9:40	12	12/27/03 18:09	12/27/03 19:26	77
8/5/03 10:01	8/5/03 11:09	68	12/28/03 17:44	12/28/03 18:47	63
8/7/03 8:09	8/7/03 8:27	18	1/3/04 14:53	1/3/04 18:59	46 start 246
8/7/03 8:36	8/7/03 12:31	235	1/4/04 20:49	1/4/04 21:01	12
8/7/03 15:20	8/7/03 15:32	12	1/5/04 7:39	1/5/04 7:56	17
8/7/03 15:49	8/7/03 16:07	18	1/5/04 10:59	1/5/04 11:00	1
8/14/03 13:20	8/14/03 13:24	4	1/5/04 11:03	1/5/04 11:08	5
8/25/03 10:30	8/25/03 11:30	60	1/5/04 11:29	1/5/04 12:24	55
8/25/03 11:51	8/25/03 14:31	160	1/5/04 12:30	1/5/04 12:31	1
8/26/03 10:38	8/26/03 12:31	113	1/5/04 12:35	1/5/04 12:45	10
8/28/03 9:20	8/28/03 9:35	15	1/5/04 17:17	1/5/04 18:33	76
8/28/03 12:00	8/28/03 12:29	29	1/5/04 23:14	1/5/04 23:18	4
9/1/03 22:21	9/1/03 22:57	36	1/5/04 23:20	1/5/04 23:33	13
9/2/03 8:12	9/2/03 9:49	97	1/5/04 23:39	1/5/04 23:41	2
9/2/03 10:13	9/2/03 10:18	5	1/5/04 23:44	1/5/04 23:53	9
9/2/03 10:52	9/2/03 10:59	7	1/6/04 3:57	1/6/04 4:55	58
9/2/03 17:14	9/2/03 17:20	6	1/8/04 16:10	1/8/04 16:12	2
9/2/03 17:32	9/2/03 17:59	27	1/8/04 16:34	1/8/04 16:35	1
9/2/03 20:46	9/2/03 21:45	59	1/8/04 16:40	1/8/04 16:42	2
9/6/03 17:05	9/6/03 17:12	7	1/8/04 19:57	1/8/04 20:58	61
9/9/03 7:44	9/9/03 8:10	26	1/21/04 7:39	1/21/04 9:28	109
9/11/03 16:04	9/11/03 17:38	94	2/7/04 14:57	2/7/04 17:27	150
9/14/03 11:38	9/14/03 13:34	52 116	2/13/04 11:42	2/13/04 12:07	25
9/14/03 16:55	9/14/03 17:57	62	2/13/04 13:04	2/13/04 14:02	58
9/16/03 14:36	9/16/03 15:15	39	2/14/04 17:41	2/14/04 18:34	53
9/18/03 10:35	9/18/03 14:27	232	2/16/04 14:08	2/16/04 17:31	203
9/22/03 16:53	9/22/03 18:27	94	2/18/04 16:23	2/18/04 22:30	367
9/23/03 14:32	9/23/03 21:37	425	2/20/04 7:18	2/20/04 8:25	29 start 67

Response to 3/15/05 Shast County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment B, Page 2 of 3
Periods of NOx emissions 1-hour rolling average over 2.00 ppm (15% O2)

Start	Stop	Minutes	Start	Stop	Minutes
2/25/04 14:47	2/25/04 14:59	12	11/11/04 5:00	11/11/04 5:07	7
2/26/04 12:05	2/26/04 14:13	128	11/11/04 6:17	11/11/04 6:19	2
4/2/04 10:44	4/2/04 11:44	60	11/11/04 6:32	11/11/04 6:33	1
4/2/04 18:12	4/2/04 19:20	68	11/11/04 6:38	11/11/04 6:40	2
4/2/04 20:15	4/2/04 20:36	21	11/13/04 4:52	11/13/04 4:57	5
4/3/04 17:19	4/3/04 19:12	113	11/13/04 13:03	11/13/04 15:49	166
4/4/04 15:55	4/4/04 18:05	130	11/19/04 12:41	11/19/04 12:47	6
4/5/04 13:01	4/5/04 15:35	154	11/23/04 9:59	11/23/04 10:10	11
4/19/04 7:31	4/19/04 10:57	206	11/24/04 18:06	11/24/04 18:13	7
4/21/04 21:27	4/21/04 21:39	12	11/24/04 18:34	11/24/04 18:53	19
4/25/04 10:45	4/25/04 11:15	30	11/24/04 19:12	11/24/04 19:25	13
4/28/04 14:10	4/28/04 16:54	164	11/24/04 19:49	11/24/04 19:58	9
5/2/04 18:24	5/2/04 20:30	126	11/24/04 20:26	11/24/04 20:36	10
5/11/04 9:43	5/11/04 11:50	127	11/24/04 20:43	11/24/04 21:51	68
6/4/04 15:22	6/4/04 16:30	68	11/27/04 7:55	11/27/04 7:59	4
6/11/04 6:57	6/11/04 7:58	61	11/28/04 18:10	11/28/04 19:05	55
6/11/04 10:22	6/11/04 11:32	70	11/29/04 12:57	11/29/04 13:47	50
6/11/04 15:37	6/11/04 17:05	88	11/29/04 14:11	11/29/04 14:14	3
6/14/04 6:33	6/14/04 8:25	112	11/29/04 14:41	11/29/04 14:57	16
7/12/04 9:32	7/12/04 14:49	18 Start 317	11/29/04 15:19	11/29/04 15:24	5
8/8/04 8:36	8/8/04 12:16	220	11/29/04 17:03	11/29/04 18:54	111
9/11/04 9:23	9/11/04 9:45	22	12/1/04 7:52	12/1/04 9:47	1+3 ~~start~~ 115
9/13/04 10:14	9/13/04 11:07	53	12/1/04 10:05	12/1/04 11:24	79
9/14/04 7:36	9/14/04 8:37	61	12/1/04 17:50	12/1/04 21:59	249
9/17/04 0:24	9/17/04 1:17	53	12/2/04 9:49	12/2/04 11:09	80
9/23/04 15:36	9/23/04 17:03	87	12/2/04 18:09	12/2/04 18:17	8
9/23/04 17:21	9/23/04 18:18	57	12/2/04 18:34	12/2/04 18:44	10
9/24/04 10:17	9/24/04 11:35	78	12/3/04 10:50	12/3/04 11:06	16
9/24/04 13:24	9/24/04 14:19	55	12/4/04 20:59	12/4/04 22:08	69
9/24/04 18:21	9/24/04 19:26	65	12/12/04 16:51	12/12/04 16:52	1
9/26/04 15:49	9/26/04 16:24	35	12/12/04 16:54	12/12/04 17:09	15
9/27/04 16:02	9/27/04 16:14	12	12/13/04 11:19	12/13/04 12:44	85
9/27/04 16:35	9/27/04 17:04	29	12/14/04 7:16	12/14/04 8:07	51
9/30/04 19:03	9/30/04 19:08	5	12/14/04 9:28	12/14/04 9:52	24
10/1/04 10:56	10/1/04 12:27	91	12/14/04 9:55	12/14/04 9:56	1
11/1/04 9:20	11/1/04 13:22	242	12/14/04 9:59	12/14/04 10:15	16
11/1/04 14:16	11/1/04 17:03	167	12/14/04 15:00	12/14/04 15:12	12
11/1/04 19:30	11/1/04 21:14	104	12/14/04 15:24	12/14/04 15:47	23
11/2/04 14:36	11/2/04 21:20	10 start 404	12/14/04 17:36	12/14/04 17:37	1
11/5/04 11:52	11/5/04 14:07	135	12/14/04 17:39	12/14/04 18:03	24
11/8/04 5:44	11/8/04 8:07	143	12/14/04 18:05	12/14/04 18:28	23
11/11/04 1:06	11/11/04 1:08	2	12/14/04 18:41	12/14/04 19:01	20
11/11/04 1:10	11/11/04 1:26	16	12/14/04 19:14	12/14/04 19:15	1
11/11/04 4:28	11/11/04 4:41	13	12/14/04 19:17	12/14/04 19:33	16

Response to 3/15/05 Shast County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment B, Page 3 of 3
Periods of NOx emissions 1-hour rolling average over 2.00 ppm (15% O2)

Start	Stop	Minutes	Start	Stop	Minutes
12/14/04 19:45	12/14/04 23:33	228	1/5/05 18:06	1/5/05 18:14	8
12/15/04 6:54	12/15/04 7:57	63	1/5/05 19:51	1/5/05 20:36	45
12/15/04 9:15	12/15/04 10:47	92	1/6/05 18:43	1/6/05 18:44	1
12/15/04 12:35	12/15/04 12:47	12	1/6/05 18:46	1/6/05 19:30	44
12/15/04 13:01	12/15/04 13:02	1	1/7/05 21:53	1/7/05 22:02	9
12/15/04 17:43	12/15/04 18:48	65	1/7/05 22:05	1/7/05 23:25	80
12/15/04 18:50	12/15/04 19:06	16	1/9/05 7:05	1/9/05 8:08	63
12/15/04 19:09	12/15/04 19:12	3	1/9/05 8:13	1/9/05 9:32	79
12/15/04 19:16	12/15/04 19:38	22	1/9/05 9:35	1/9/05 9:48	13
12/15/04 19:40	12/15/04 19:44	4	1/9/05 10:05	1/9/05 10:16	11
12/15/04 19:46	12/15/04 22:16	150	1/9/05 10:31	1/9/05 10:46	15
12/16/04 6:47	12/16/04 7:35	48	1/9/05 10:58	1/9/05 12:10	72
12/16/04 8:50	12/16/04 10:00	70	1/10/05 8:05	1/10/05 8:18	13
12/16/04 19:14	12/16/04 22:10	176	1/10/05 10:21	1/10/05 10:36	15
12/17/04 7:04	12/17/04 7:59	55	1/10/05 10:48	1/10/05 11:01	13
12/17/04 10:03	12/17/04 11:09	66	1/10/05 11:24	1/10/05 11:25	1
12/17/04 15:17	12/17/04 15:58	41	1/10/05 11:50	1/10/05 11:53	3
12/17/04 18:51	12/17/04 18:53	2	1/10/05 12:12	1/10/05 12:21	9
12/17/04 19:14	12/17/04 21:22	128	1/10/05 17:21	1/10/05 17:25	4
12/17/04 22:02	12/17/04 22:19	17	1/10/05 17:34	1/10/05 19:49	135
12/18/04 6:49	12/18/04 10:22	213	1/12/05 7:01	1/12/05 10:38	217
12/18/04 10:55	12/18/04 12:07	72	1/13/05 5:55	1/13/05 7:55	120
12/18/04 20:53	12/18/04 22:12	79	1/13/05 8:02	1/13/05 8:15	13
12/20/04 12:51	12/20/04 14:01	70	1/13/05 8:30	1/13/05 8:41	11
12/20/04 17:40	12/20/04 22:06	266	1/13/05 8:43	1/13/05 8:44	1
12/21/04 8:51	12/21/04 10:13	82	1/13/05 8:48	1/13/05 12:03	195
12/21/04 17:50	12/21/04 19:55	125	1/13/05 22:29	1/13/05 23:07	38
12/21/04 20:50	12/21/04 21:23	33	1/14/05 15:24	1/14/05 16:28	64
12/22/04 8:03	12/22/04 8:44	41	1/16/05 13:37	1/16/05 16:14	157
12/22/04 9:02	12/22/04 10:11	69	1/16/05 18:01	1/16/05 20:51	170
12/22/04 18:09	12/22/04 20:52	163	1/18/05 13:35	1/18/05 16:43	188
12/23/04 8:06	12/23/04 9:30	84	1/30/05 9:20	1/30/05 12:16	176
12/28/04 18:06	12/28/04 18:23	17	2/3/05 14:20	2/3/05 17:01	161
12/28/04 18:26	12/28/04 18:44	18	2/8/05 13:52	2/8/05 14:29	37
12/28/04 18:54	12/28/04 19:08	14	2/8/05 18:58	2/8/05 19:17	19
12/28/04 19:25	12/28/04 19:40	15	2/9/05 7:42	2/9/05 8:55	73
12/28/04 19:52	12/28/04 19:56	4	2/11/05 7:58	2/11/05 10:11	133
12/30/04 7:22	12/30/04 8:19	57	3/30/05 15:00	3/30/05 16:59	60 shut 119
1/5/05 10:13	1/5/05 11:55	12 102			
1/5/05 13:03	1/5/05 13:11	8			
1/5/05 13:32	1/5/05 13:37	5			
1/5/05 15:49	1/5/05 15:56	7			
1/5/05 16:16	1/5/05 16:20	4			
1/5/05 17:41	1/5/05 17:45	4			

Response to 3/15/05 Shast County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment B, Page 1 of 3
Periods of NOx emissions 1-hour rolling average over 2.00 ppm (15% O2)

Total time over 2.00 ppm 1-hour rolling average (Hours): 296

Start	Stop	Minutes	Start	Stop	Minutes
5/12/03 8:22	5/12/03 11:27	185	9/26/03 10:43	9/26/03 11:26	43
6/9/03 10:00	6/9/03 13:33	213	9/26/03 16:02	9/26/03 16:05	3
6/10/03 10:46	6/10/03 11:22	36	9/30/03 11:49	9/30/03 21:03	554
6/10/03 16:26	6/10/03 18:55	149	10/13/03 7:08	10/13/03 8:01	53
6/11/03 10:07	6/11/03 10:55	48	10/15/03 14:57	10/15/03 15:08	11
6/11/03 16:30	6/11/03 16:50	20	10/19/03 11:00	10/19/03 12:03	63
6/12/03 9:38	6/12/03 9:52	14	10/20/03 11:09	10/20/03 15:45	276
6/12/03 15:05	6/12/03 15:52	47	10/20/03 18:04	10/20/03 18:16	12
6/25/03 15:53	6/25/03 17:30	97	10/24/03 12:04	10/24/03 13:59	115
6/26/03 15:02	6/26/03 18:08	186	11/4/03 9:25	11/4/03 9:30	5
7/1/03 10:50	7/1/03 13:03	133	11/4/03 11:53	11/4/03 11:54	1
7/2/03 9:18	7/2/03 11:26	128	11/4/03 17:42	11/4/03 17:46	4
7/8/03 18:59	7/8/03 19:12	13	11/17/03 7:33	11/17/03 11:16	223
7/10/03 18:12	7/10/03 19:12	60	12/17/03 14:17	12/17/03 15:20	63
7/11/03 19:01	7/11/03 20:15	74	12/17/03 15:34	12/17/03 15:50	16
8/5/03 8:54	8/5/03 8:57	3	12/27/03 5:57	12/27/03 6:15	18
8/5/03 9:28	8/5/03 9:40	12	12/27/03 18:09	12/27/03 19:26	77
8/5/03 10:01	8/5/03 11:09	68	12/28/03 17:44	12/28/03 18:47	63
8/7/03 8:09	8/7/03 8:27	18	1/3/04 14:53	1/3/04 18:59	246
8/7/03 8:36	8/7/03 12:31	235	1/4/04 20:49	1/4/04 21:01	12
8/7/03 15:20	8/7/03 15:32	12	1/5/04 7:39	1/5/04 7:56	17
8/7/03 15:49	8/7/03 16:07	18	1/5/04 10:59	1/5/04 11:00	1
8/14/03 13:20	8/14/03 13:24	4	1/5/04 11:03	1/5/04 11:08	5
8/25/03 10:30	8/25/03 11:30	60	1/5/04 11:29	1/5/04 12:24	55
8/25/03 11:51	8/25/03 14:31	160	1/5/04 12:30	1/5/04 12:31	1
8/26/03 10:38	8/26/03 12:31	113	1/5/04 12:35	1/5/04 12:45	10
8/28/03 9:20	8/28/03 9:35	15	1/5/04 17:17	1/5/04 18:33	76
8/28/03 12:00	8/28/03 12:29	29	1/5/04 23:14	1/5/04 23:18	4
9/1/03 22:21	9/1/03 22:57	36	1/5/04 23:20	1/5/04 23:33	13
9/2/03 8:12	9/2/03 9:49	97	1/5/04 23:39	1/5/04 23:41	2
9/2/03 10:13	9/2/03 10:18	5	1/5/04 23:44	1/5/04 23:53	9
9/2/03 10:52	9/2/03 10:59	7	1/6/04 3:57	1/6/04 4:55	58
9/2/03 17:14	9/2/03 17:20	6	1/8/04 16:10	1/8/04 16:12	2
9/2/03 17:32	9/2/03 17:59	27	1/8/04 16:34	1/8/04 16:35	1
9/2/03 20:46	9/2/03 21:45	59	1/8/04 16:40	1/8/04 16:42	2
9/6/03 17:05	9/6/03 17:12	7	1/8/04 19:57	1/8/04 20:58	61
9/9/03 7:44	9/9/03 8:10	26	1/21/04 7:39	1/21/04 9:28	109
9/11/03 16:04	9/11/03 17:38	94	2/7/04 14:57	2/7/04 17:27	150
9/14/03 11:38	9/14/03 13:34	116	2/13/04 11:42	2/13/04 12:07	25
9/14/03 16:55	9/14/03 17:57	62	2/13/04 13:04	2/13/04 14:02	58
9/16/03 14:36	9/16/03 15:15	39	2/14/04 17:41	2/14/04 18:34	53
9/18/03 10:35	9/18/03 14:27	232	2/16/04 14:08	2/16/04 17:31	203
9/22/03 16:53	9/22/03 18:27	94	2/18/04 16:23	2/18/04 22:30	367
9/23/03 14:32	9/23/03 21:37	425	2/20/04 7:18	2/20/04 8:25	67

Response to 3/15/05 Shast County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment B, Page 2 of 3
Periods of NOx emissions 1-hour rolling average over 2.00 ppm (15% O2)

Start	Stop	Minutes	Start	Stop	Minutes
2/25/04 14:47	2/25/04 14:59	12	11/11/04 5:00	11/11/04 5:07	7
2/26/04 12:05	2/26/04 14:13	128	11/11/04 6:17	11/11/04 6:19	2
4/2/04 10:44	4/2/04 11:44	60	11/11/04 6:32	11/11/04 6:33	1
4/2/04 18:12	4/2/04 19:20	68	11/11/04 6:38	11/11/04 6:40	2
4/2/04 20:15	4/2/04 20:36	21	11/13/04 4:52	11/13/04 4:57	5
4/3/04 17:19	4/3/04 19:12	113	11/13/04 13:03	11/13/04 15:49	166
4/4/04 15:55	4/4/04 18:05	130	11/19/04 12:41	11/19/04 12:47	6
4/5/04 13:01	4/5/04 15:35	154	11/23/04 9:59	11/23/04 10:10	11
4/19/04 7:31	4/19/04 10:57	206	11/24/04 18:06	11/24/04 18:13	7
4/21/04 21:27	4/21/04 21:39	12	11/24/04 18:34	11/24/04 18:53	19
4/25/04 10:45	4/25/04 11:15	30	11/24/04 19:12	11/24/04 19:25	13
4/28/04 14:10	4/28/04 16:54	164	11/24/04 19:49	11/24/04 19:58	9
5/2/04 18:24	5/2/04 20:30	126	11/24/04 20:26	11/24/04 20:36	10
5/11/04 9:43	5/11/04 11:50	127	11/24/04 20:43	11/24/04 21:51	68
6/4/04 15:22	6/4/04 16:30	68	11/27/04 7:55	11/27/04 7:59	4
6/11/04 6:57	6/11/04 7:58	61	11/28/04 18:10	11/28/04 19:05	55
6/11/04 10:22	6/11/04 11:32	70	11/29/04 12:57	11/29/04 13:47	50
6/11/04 15:37	6/11/04 17:05	88	11/29/04 14:11	11/29/04 14:14	3
6/14/04 6:33	6/14/04 8:25	112	11/29/04 14:41	11/29/04 14:57	16
7/12/04 9:32	7/12/04 14:49	317	11/29/04 15:19	11/29/04 15:24	5
8/8/04 8:36	8/8/04 12:16	220	11/29/04 17:03	11/29/04 18:54	111
9/11/04 9:23	9/11/04 9:45	22	12/1/04 7:52	12/1/04 9:47	115
9/13/04 10:14	9/13/04 11:07	53	12/1/04 10:05	12/1/04 11:24	79
9/14/04 7:36	9/14/04 8:37	61	12/1/04 17:50	12/1/04 21:59	249
9/17/04 0:24	9/17/04 1:17	53	12/2/04 9:49	12/2/04 11:09	80
9/23/04 15:36	9/23/04 17:03	87	12/2/04 18:09	12/2/04 18:17	8
9/23/04 17:21	9/23/04 18:18	57	12/2/04 18:34	12/2/04 18:44	10
9/24/04 10:17	9/24/04 11:35	78	12/3/04 10:50	12/3/04 11:06	16
9/24/04 13:24	9/24/04 14:19	55	12/4/04 20:59	12/4/04 22:08	69
9/24/04 18:21	9/24/04 19:26	65	12/12/04 16:51	12/12/04 16:52	1
9/26/04 15:49	9/26/04 16:24	35	12/12/04 16:54	12/12/04 17:09	15
9/27/04 16:02	9/27/04 16:14	12	12/13/04 11:19	12/13/04 12:44	85
9/27/04 16:35	9/27/04 17:04	29	12/14/04 7:16	12/14/04 8:07	51
9/30/04 19:03	9/30/04 19:08	5	12/14/04 9:28	12/14/04 9:52	24
10/1/04 10:56	10/1/04 12:27	91	12/14/04 9:55	12/14/04 9:56	1
11/1/04 9:20	11/1/04 13:22	242	12/14/04 9:59	12/14/04 10:15	16
11/1/04 14:16	11/1/04 17:03	167	12/14/04 15:00	12/14/04 15:12	12
11/1/04 19:30	11/1/04 21:14	104	12/14/04 15:24	12/14/04 15:47	23
11/2/04 14:36	11/2/04 21:20	404	12/14/04 17:36	12/14/04 17:37	1
11/5/04 11:52	11/5/04 14:07	135	12/14/04 17:39	12/14/04 18:03	24
11/8/04 5:44	11/8/04 8:07	143	12/14/04 18:05	12/14/04 18:28	23
11/11/04 1:06	11/11/04 1:08	2	12/14/04 18:41	12/14/04 19:01	20
11/11/04 1:10	11/11/04 1:26	16	12/14/04 19:14	12/14/04 19:15	1
11/11/04 4:28	11/11/04 4:41	13	12/14/04 19:17	12/14/04 19:33	16

Response to 3/15/05 Shast County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment B, Page 3 of 3
Periods of NOx emissions 1-hour rolling average over 2.00 ppm (15% O2)

Start	Stop	Minutes	Start	Stop	Minutes
12/14/04 19:45	12/14/04 23:33	228	1/5/05 18:06	1/5/05 18:14	8
12/15/04 6:54	12/15/04 7:57	63	1/5/05 19:51	1/5/05 20:36	45
12/15/04 9:15	12/15/04 10:47	92	1/6/05 18:43	1/6/05 18:44	1
12/15/04 12:35	12/15/04 12:47	12	1/6/05 18:46	1/6/05 19:30	44
12/15/04 13:01	12/15/04 13:02	1	1/7/05 21:53	1/7/05 22:02	9
12/15/04 17:43	12/15/04 18:48	65	1/7/05 22:05	1/7/05 23:25	80
12/15/04 18:50	12/15/04 19:06	16	1/9/05 7:05	1/9/05 8:08	63
12/15/04 19:09	12/15/04 19:12	3	1/9/05 8:13	1/9/05 9:32	79
12/15/04 19:16	12/15/04 19:38	22	1/9/05 9:35	1/9/05 9:48	13
12/15/04 19:40	12/15/04 19:44	4	1/9/05 10:05	1/9/05 10:16	11
12/15/04 19:46	12/15/04 22:16	150	1/9/05 10:31	1/9/05 10:46	15
12/16/04 6:47	12/16/04 7:35	48	1/9/05 10:58	1/9/05 12:10	72
12/16/04 8:50	12/16/04 10:00	70	1/10/05 8:05	1/10/05 8:18	13
12/16/04 19:14	12/16/04 22:10	176	1/10/05 10:21	1/10/05 10:36	15
12/17/04 7:04	12/17/04 7:59	55	1/10/05 10:48	1/10/05 11:01	13
12/17/04 10:03	12/17/04 11:09	66	1/10/05 11:24	1/10/05 11:25	1
12/17/04 15:17	12/17/04 15:58	41	1/10/05 11:50	1/10/05 11:53	3
12/17/04 18:51	12/17/04 18:53	2	1/10/05 12:12	1/10/05 12:21	9
12/17/04 19:14	12/17/04 21:22	128	1/10/05 17:21	1/10/05 17:25	4
12/17/04 22:02	12/17/04 22:19	17	1/10/05 17:34	1/10/05 19:49	135
12/18/04 6:49	12/18/04 10:22	213	1/12/05 7:01	1/12/05 10:38	217
12/18/04 10:55	12/18/04 12:07	72	1/13/05 5:55	1/13/05 7:55	120
12/18/04 20:53	12/18/04 22:12	79	1/13/05 8:02	1/13/05 8:15	13
12/20/04 12:51	12/20/04 14:01	70	1/13/05 8:30	1/13/05 8:41	11
12/20/04 17:40	12/20/04 22:06	266	1/13/05 8:43	1/13/05 8:44	1
12/21/04 8:51	12/21/04 10:13	82	1/13/05 8:48	1/13/05 12:03	195
12/21/04 17:50	12/21/04 19:55	125	1/13/05 22:29	1/13/05 23:07	38
12/21/04 20:50	12/21/04 21:23	33	1/14/05 15:24	1/14/05 16:28	64
12/22/04 8:03	12/22/04 8:44	41	1/16/05 13:37	1/16/05 16:14	157
12/22/04 9:02	12/22/04 10:11	69	1/16/05 18:01	1/16/05 20:51	170
12/22/04 18:09	12/22/04 20:52	163	1/18/05 13:35	1/18/05 16:43	188
12/23/04 8:06	12/23/04 9:30	84	1/30/05 9:20	1/30/05 12:16	176
12/28/04 18:06	12/28/04 18:23	17	2/3/05 14:20	2/3/05 17:01	161
12/28/04 18:26	12/28/04 18:44	18	2/8/05 13:52	2/8/05 14:29	37
12/28/04 18:54	12/28/04 19:08	14	2/8/05 18:58	2/8/05 19:17	19
12/28/04 19:25	12/28/04 19:40	15	2/9/05 7:42	2/9/05 8:55	73
12/28/04 19:52	12/28/04 19:56	4	2/11/05 7:58	2/11/05 10:11	133
12/30/04 7:22	12/30/04 8:19	57	3/30/05 15:00	3/30/05 16:59	119
1/5/05 10:13	1/5/05 11:55	102			
1/5/05 13:03	1/5/05 13:11	8			
1/5/05 13:32	1/5/05 13:37	5			
1/5/05 15:49	1/5/05 15:56	7			
1/5/05 16:16	1/5/05 16:20	4			
1/5/05 17:41	1/5/05 17:45	4			

Response to 3/15/05 Shasta County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment C, Page 1 of 2

Unit 5 SCONOX Maintenance & Repairs Since 06/2002.

ALSTOM

MEMORANDUM

Power Environment

Environmental Control Systems

Date: 3/24/2005

Subject: Unit 5 SCONOx Maintenance & Repairs Since 06/2002

		Maintenance/Repair	Reasons & Results
1	10/2002	Damper seal gasket	Excessive leakage found on the original seal gasket. A new type of seal gasket was used to replace the original gasket.
2	10/2002	Steam Reformer Reactor	The original reformer reactor was not equipped with relief valve, reactor bulged during commissioning. New reactor installed to replace the original, with better access for maintenance.
3	01/2003	Steam Heater	Design temperature was insufficient for the regeneration gas production. Reforming temperature increased by 60 °F with heater.
4	06/2003	Regen Distribution Plate	Fluid dynamics study shows that the original design was unsatisfactory. New distribution plate was designed.
5	10/2003	Larger Sulfur Filter for the Steam Reformer	Original sulfur filter was undersized. A 12″x4′ sulfur filter was installed to replace the original 8″x4′ filter.
6	03/2005	Regeneration Purge	Latest pilot plant study found that catalyst poisoning will be reduced by 2/3 by purging operation, and regeneration consumption of steam and natural gas can be significantly reduced.
7	04/2005	2nd Layer SCOSOx Catalyst	Trouble-shooting efforts found that one layer of SCOSOx catalyst was insufficient to prevent SCONOx catalyst poisoning. 2nd layer SCOSOx catalyst will be added.

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Response to 3/15/05 Shasta County AQMD Information Request
"Unit 5 Oxides of Nitrogen Demonstration Limit"
Attachment D

Summary of upsets or malfunctions not reported or covered in Attachment C.

The SCONOX regen gas supply valves were upgraded to Class 6 valves.

Additional information relative to the SCONOX system installation, operation and maintenance not presented in Attachment A through D.

To date, the SCONOX catalyst has been washed on eleven occasions. All three layers of SCONOX catalyst were washed on 2 of the washings, only the first layer of SCONOX catalyst was washed on 8 of the washings, and the SCOSOX has never been washed.

An additional layer of SCOSOX catalyst was added during the April 2005 Outage.

Attachment E includes yearly load evaluations using DAHS software programmed to perform the load analysis required by 40 CFR 75, Appendix A. The load evaluations show that Unit 5 has been mostly run at low loads.

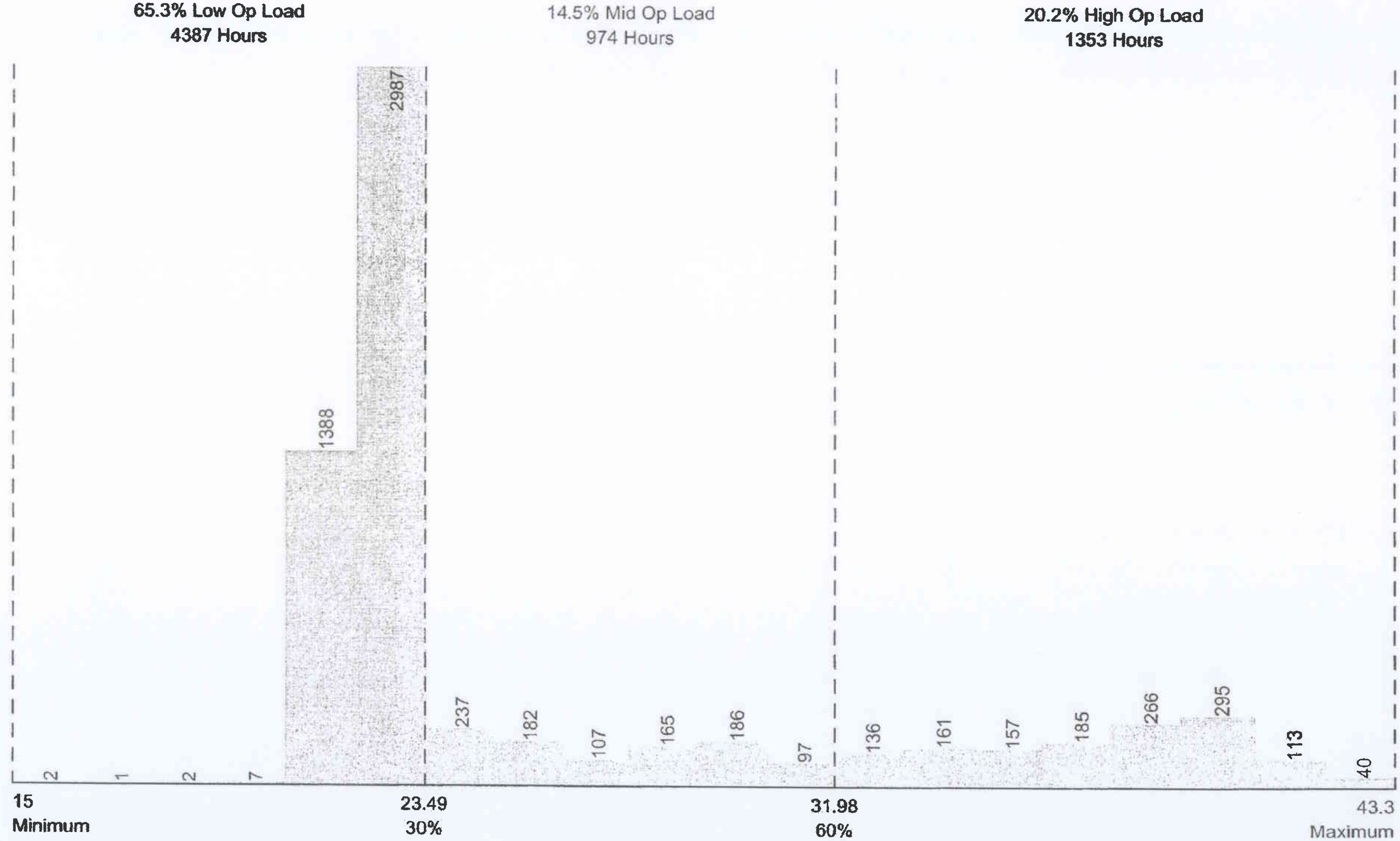
Attachment E includes copies of the operators Start/Start log for Unit 5.

REDDING POWER

Load Evaluation Summary

Load summary ending the last day of 2004 Q2

CT Megawatts 1-Hr Turbine - 5



Load Evaluation Summary 3/22/2005 03:27 PM

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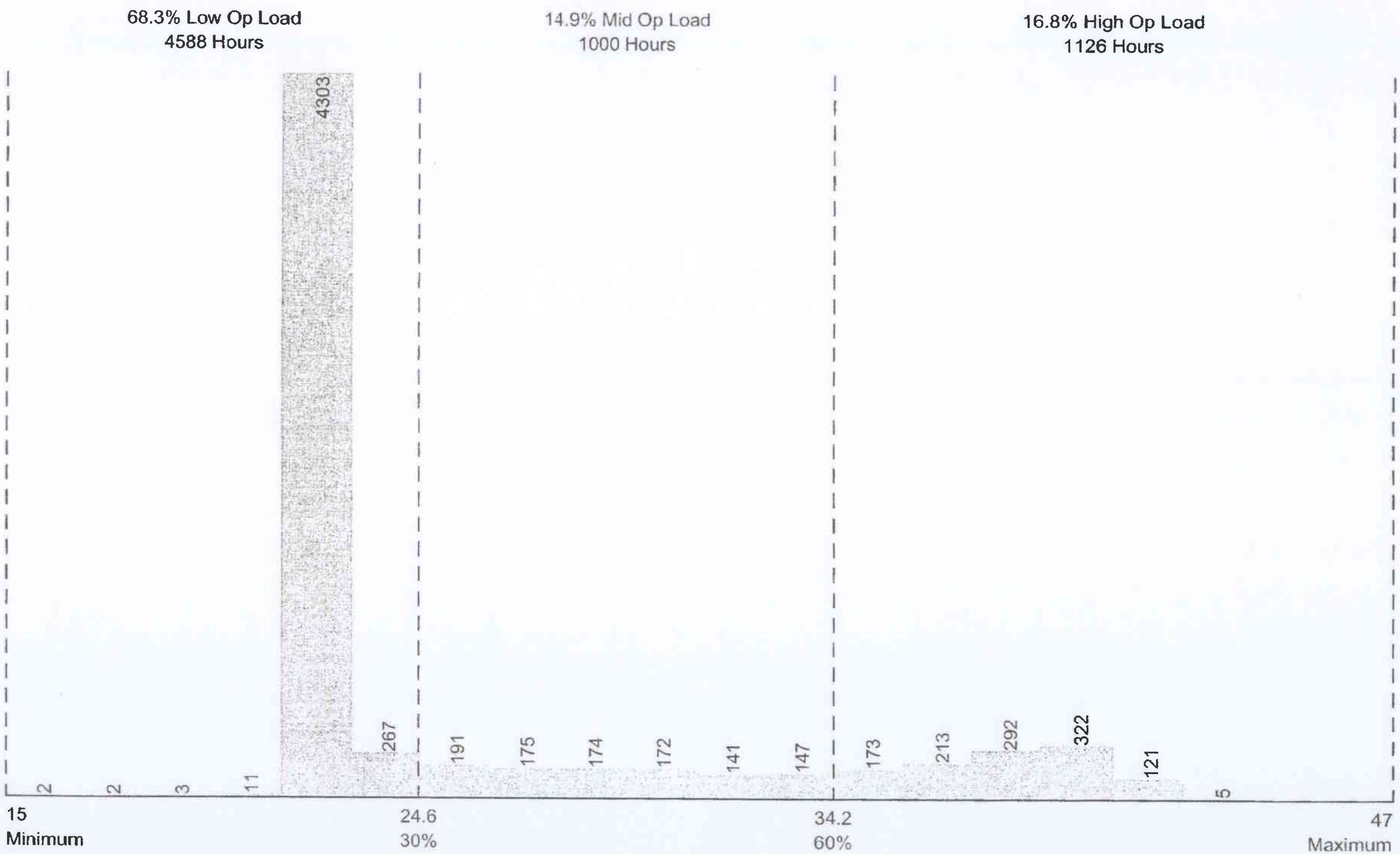
REDDING POWER

Load Evaluation Summary

Load summary ending the last day of 2004 Q2

CT Megawatts 1-Hr Turbine - 5



Load Evaluation Summary 3/22/2005 03:26 PM

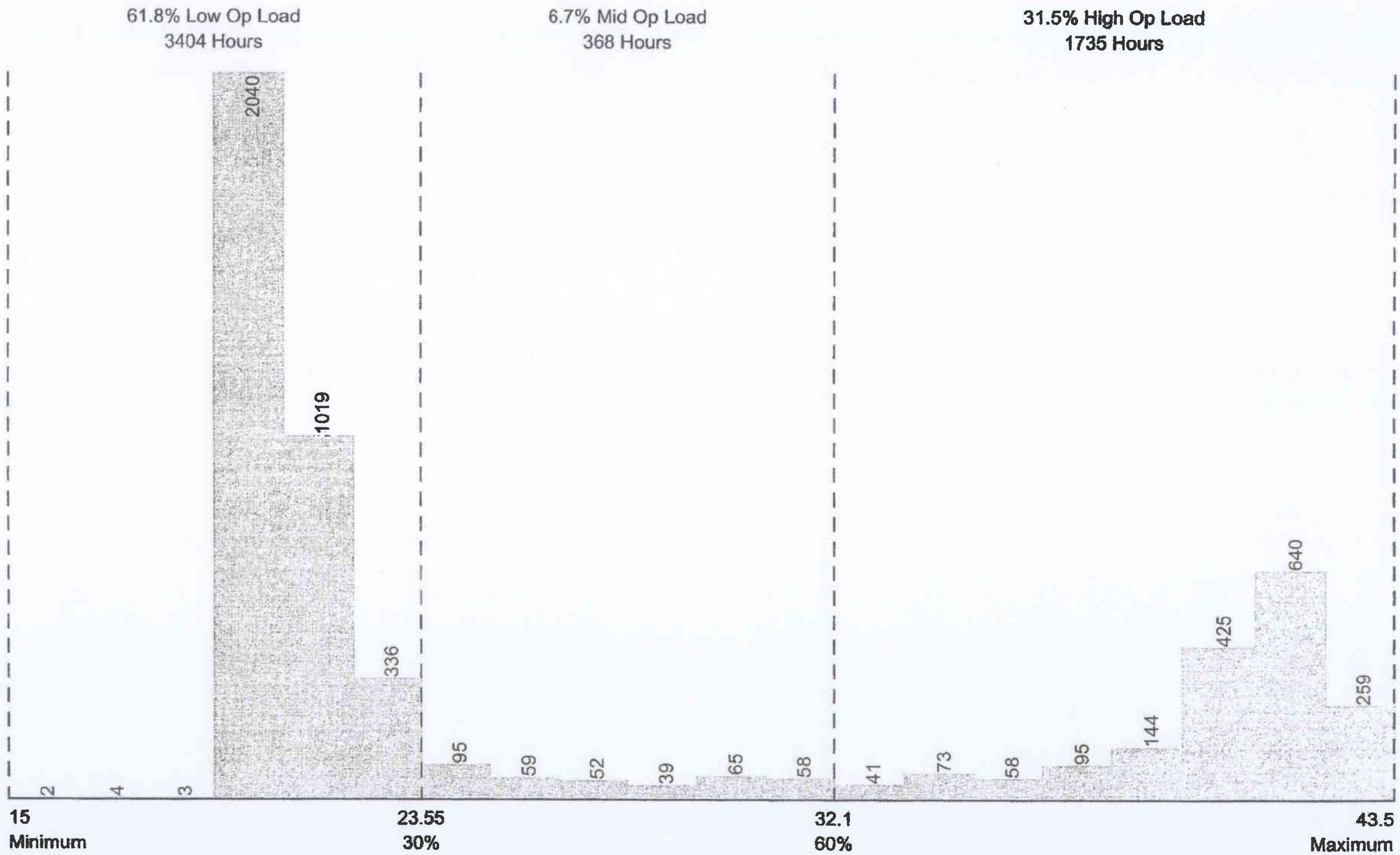
110

REDDING POWER

Load Evaluation Summary

Load summary ending the last day of 2003 **Q2**

CT Megawatts 1-Hr Turbine - 5



Load Evaluation Summary 3/22/2005 03:28 PM

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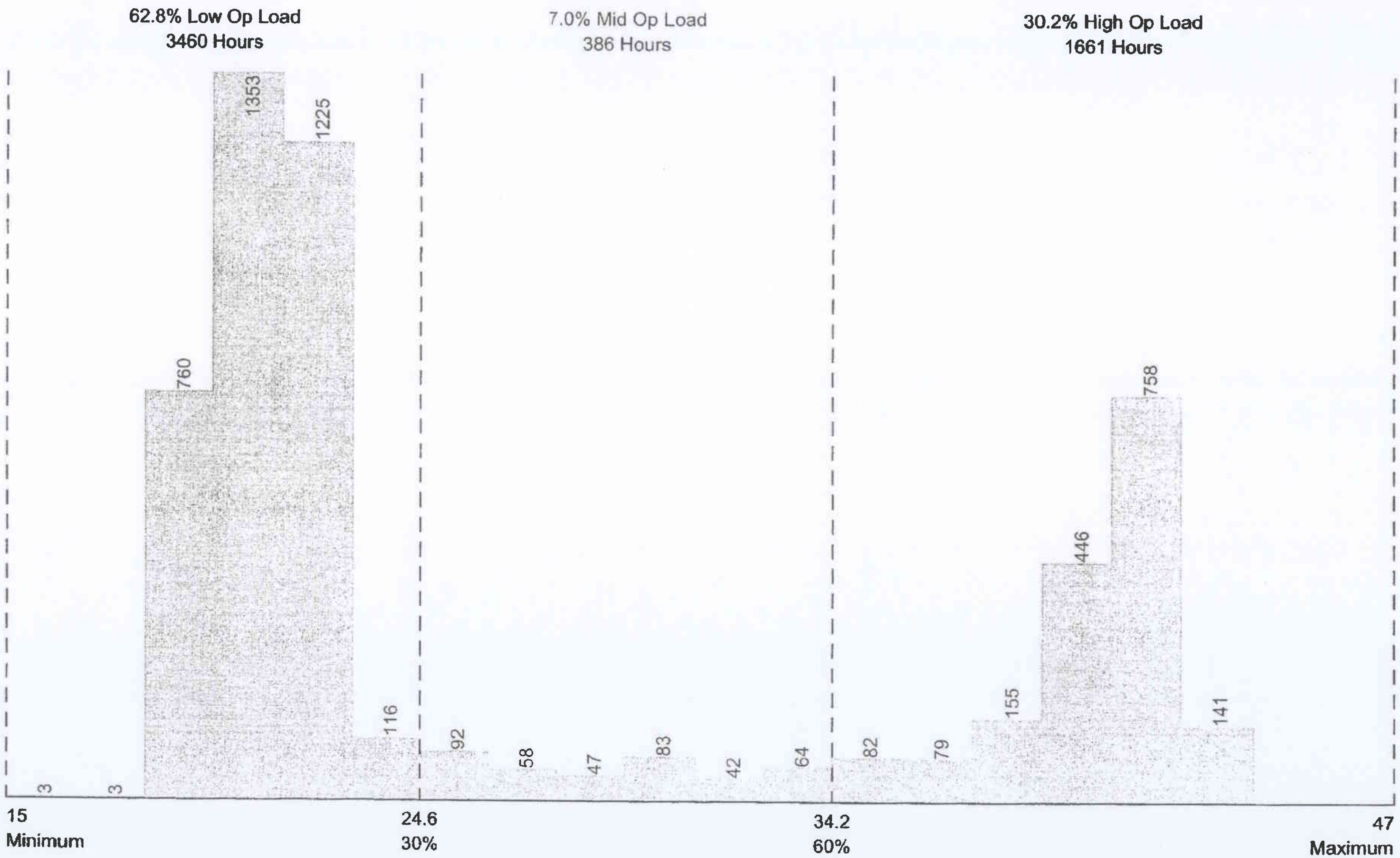
REDDING POWER

Load Evaluation Summary

Load summary ending the last day of 2003 Q2

CT Megawatts 1-Hr Turbine - 5



Load Evaluation Summary 3/22/2005 03:28 PM

AP M

Unit 5 Startup/Shutdown Log

Outage Number from 04/15/2002 (Initial Start)	Date/Time On Line	Date/Time Off Line	Days/Hours On Line	Total Gas Use	Total MW Generated	Reason On Line
1	4-15-02 1545	4-15-02 1615	.5 hrs			Startup Testing
2	4-19-02 1045	4-20-02 0758	19.22 hrs			Startup Testing
3	4-22-02 1151	4-22-02 1156	.08 hrs			Startup Testing
4	4-22-02 1159	4-22-02 1320	1.35 hrs			Startup Testing
5	4-22-02 1549	4-22-02 1602	.22 hrs			Startup Testing
6	4-23-02 1452	4-23-02 1518	.43 hrs			Startup Testing
7	4-23-02 1645	4-23-02 1714	.48 hrs			Startup Testing
8	4-24-02 1150	4-24-02 1212	.37 hrs			Startup Testing
9	4-24-02 1410	4-24-02 1730	3.33 hrs			Startup Testing
10	4-26-02 1636	4-26-02 1815	1.73 hrs			Startup Testing
11	4-27-02 1237	4-27-02 1336	.98 hrs			
12	4-29-02 1010	4-29-02 1449	4.65 hrs			
13	5-1-02 1206	5-1-02 1228	.37 hrs			
14	5-1-02 1426	5-1-02 1535	1.15 hrs			
15	5-1-02 1615	5-1-02 1815	2.0 hrs			
16	5-2-02 1007	5-2-02 1444	4.62 hrs			
17	5-2-02 1446	5-2-02 1728	2.7 hrs			
18	5-3-02 1320	5-3-02 1744	4.4 hrs			
19	5-4-02 0828	5-4-02 1338	5.17 hrs			
20	5-5-02 0843	5-5-02 1115	2.53 hrs			
21	5-6-02 0809	5-6-02 1713	9.07 hrs			
22	5-7-02 0802	5-7-02 1720	9.30 hrs			
23	5-8-02 0830	5-8-02 1737	9.12 hrs			US TESTING

83.77

Unit 5 Startup/Shutdown Log

Outage Number from 04/15/2002 (Initial Start)	Date/Time On Line	Date/Time Off Line	Days/Hours On Line	Total Gas Use	Total MW Generated	Reason On Line
24	5-9-02 0904	5-2-02 1809	9.08hrs			US TESTING
25	5-10-02 0808	5-10-02 1819	9.18hrs			
26	5-11-02 0848	5-11-02 2305	14.28hrs			
27	5-12-02 0817	5-12-02 1702	8.75hrs			
28	5-13-02 0653	5-13-02 2307	14.23 hrs			
29	5-21-02 1314	5-21-02 1740	4.43hrs			
30	5-27-02 2000	5-29-02 1015	38.25hrs			
31	5-29-02 1035	5-31-02 14/18	51.72hrs			TRIP
32	6-1-02 11/12	6-3-02 0004	60.87 HRS			
33	6-18-02 0801	6-18-02 1001	2.0 HRS			TRIP Voltage Reg
34	6-18-02 1005	6-18-02 1024	0.32 HRS			"
35	6-18-02 1028	6-18-02 1037	0.15 HRS			"
36	6-18-02 1043	6-22-02 1154	97.18hrs	38989	3248.4	US TEST / Sales
37	6-24-02 0822	7-4-02 0204	209.7 HRS	80,920	GROSS 6297.1 / 6215.7 NET	HOT WEATHER
38	7-9-02 1440	7-31-02 0156	517.27hrs	177,100	13,258.3 Gross / NET 13,075.4	City Use
39	7-31-02 0441	8-10-02 2217	257.2 hrs			HOT WEATHER
40	8-12-02 1128	8-23-02 1403	266.58 hrs			Hot Weather
41	8-27-02 1320	8-28-02 1531	26.18hrs	7097		~~HOT WEATHER~~ WEATHER
42	8-28-02 1630	9-6-02 0708	206.6			HOT WEATHER
43	9-9-02 1047	9-21-02 0711	284.4 hrs			MAINT.
44	9-23-02 0751	10-4-02 2204	254.23hrs			HOT WEATHER
45	10-9-02 0745	10-18-02 2200	230.25hr			MAINT on UNITS
46	15 Dec 02 1513	12-17-02 2003	52.83hrs			Test Run

2639.44

UNIT 5 STARTUP SHUT DOWN LOG

	OUTAGE # from ~~[illegible]~~ 12-17-02	DATE / TIME ON LINE	DATE / TIME OFF LINE	DAYS/ HOURS ON LINE	TOTAL GAS USE	TOTAL MW GENERATED	REASON [illegible] LINE
	47	12-17-02 2120	12-18-02 1729	20.15			
2002	48	12-18-02 1803	12-18-02 1930	1.45			
2003	49	1-14-03 0851	1-14-03 1419	5.47 HRS			S/U FOR TESTING AFTER REPAIRS
	50	1-14-03 1555	1-26-03 1710	289.25			RESTART AFTER MODIFICATIONS.
	51	1-30-03 1345	2-3-03 0550	87.08			ICE AT COMPRE[illegible] INLET
	52	2-4-03 1147	3-7-03 2215	787.47			
	53	10 Mar 03 1955	3-18-03 1500	163.08			
	54	1 APRIL 03 0550	4-6-03 1658	131.13			U-5 TRIP (DWIGHT TRIP)
	55	4-6-03 1750	5-2-03 2000	626.16			U 5 SCONOX WORK
	56	5-5-03 0440	5-9-03 1600	83.27			UNIT 5 SCONOX Repair
	57	5-12-03 0825	6-26-03 2027	45.50			U5 SCONOX REPAIRS
	58	7-1-03 1116	7-1-03 2023	9.12			BLOWN GASKET ON GTX
	59	7-2-03 0937	8-22-03 1400	1238.38			"B" BOILER TUBE LEAK REPAIR
	60	25 Aug 03 1216	25 Aug 03 1407	1.85	477.9		SYS Load
	61	26 Aug 03 1100	10-19-03 1102	1296.03			INSPECTION (TURBINE) SYS Load SCR & REFORMER LOO[illegible]
	62	20 oct 03 1216	20 oct 03 1717	5.02			Test run for Siemans
	63	24 OCT 03 1202	24 OCT 03 1205	.05		0	UNIT S/D PRIOR TO BRKR CLOSURE DUE TO GAS LEAK
	64	24 OCT 03 1248	12 NOV 03 2357	468.15			ECW. TRIP
	65	11-17-03 0759	2203 12-4-03	1166.06 HRS			UNIT 5265 ELEC. WORK ALSTOM WARRENTY WORK COMBUSTOR LEAK VIBR.
	66	12-9-03 0801	1-8-04 1959	731.56 HR			U5 WARRANTY [illegible] WORK [illegible]

2003-7134.93

9796.02

66.1

133

UNIT 5 STARTUP SHUT DOWN LOG

OUTAGE # from 01/01/96	DATE / TIME ON LINE	DATE / TIME OFF LINE	DAYS/ HOURS ON LINE	TOTAL GAS USE	TOTAL MW GENERATED	[illegible] ~~U5 BFP 1A FAIL CAUSED TRIP~~
67	1-21-04 0800	2-6-04 1302	389.03 hrs			U5 BFP 1A FAILED MOTOR BEARING - TR. OUTAGE
68	2-7-04 1514	2-25-04 1400	430.76			
69	4-2-04 1914	4-2-04 2353	4.65HRS	1677.7	136MW	TOOK U5 OFFL. FOR SIEMANS TO BALANCE AFTER OVERHAUL
70	4-3-04 1742	4-3-04 2303	5.25HRS	1887.5	164.6	" " " " " "
71	4-4-04 1717	4-4-04 2102	3.75HRS	1246.5	103.3	" " " "
72	4-5-04 1436	4-17-04 0405	277.48 hrs			L/O TEMP (HIGH PROBLEM
73	4-19-04 0900	4-28-04 0306	210.1	67,033.7	5,631.4	1B BFP MOTOR CHANGED
74	4-28-04 1533	4-30-04 1929	51.9 hrs	15,221.8	1202.4	U4 GEN RTD Trip
75	5-2-04 1951	6-3-04 0000	748.15	249,509.3	20,971.9	SHUTDOWN FOR FUEL NOZZLE REPLACE
76	6-11-04 1145	6-11-04 1300	1.25HRS			IGU FAILURE
77	6-11-04 1650	6-12-04 1245	19.91 HRS.			TESTING COMPL. (REMOVE TEST EQUI.
78	6-14-04 0800	7-12-04 0901	673.02			U5 TRIPPED DUE HIGH PULSATION
79	7.12.04 0930	— FAIL TO	FIRE	—	—	FAIL TO FIRE
80	7.12.04 1022 ~~0955~~	8-5-04 1923	585.46 Hr			S/D TO CHECK NOZZLE PLUS other work
81	8-8-04 1042					

outglogi

11,168.94
to 5-2-04

STARTUP - SHU[illegible]WN LOG SHEET UN[illegible] 5

31 3.75 9.25 12

OUTAGE #	DATE - TIME OFF LINE	DATE-TIME ON LINE	FORCE or SCHED OFF? (F/S)	HOURS UNAVAILABLE	REASON OFF LINE
81	9-30-04 1915	11-1-04 0917	S	734.54	INSTALL DUMP CONDENSER
82	11-1-04 1221	11-1-04 1417	F	1.93 HR	MYSTERY TRIP - POSSIBLY W/O PROBLEM
83	11-1-04 1603	11-1-04 1945	F	3.7 HR	TRIPPED ON LOW LUBE OIL PRESSURE
84	11-1-04 2014	11-2-04 1454	F	18.5 HRS	RUPTURE DISC FAILURE
85	11-8-04 0058	11-8-04 [illegible]	F	5.02	WOODY FAIL - CPU FAULT
86	11-13-04 0400	11-13-04 1325	S	9.42	SCHEDULED OUTAGE FOR SCR NOX CATALYST CHANGE-OUT.
87	1-13-05 2207	1-16-05 1332	F	63.42 HRS	SCHEDULED OUTAGE FOR [illegible] CAT CHANGE & BURNER REPAIR.
88	1-16-05 1536	1-16-05 1757	F	2.35 HRS	- DIRTY FIRE EYES
89	1-16-05 2049	1-18-05 1300	F	40.18 HRS	E-STOP - DUE TO HIGH PULSATION
90	1-27-05 2203	1-30-05 0947	S	59.73	OUTAGE FOR TEMP. INSTALL OF PULSATION SENSING EQUIP
91	2-3-05 [illegible]	2-3-05 1934	F	3.83	[illegible] DUE TO [illegible] 1/210 AE [illegible]
92	3-31-05 2157	5-1-05 [illegible]	S	734.48	SPRING OUTAGE
93	5-1-05 330	5-2-05 0145	S	11.5	TESTING - NO WHERE TO PUT THE POWER
94	5-2-05 1311	5-3-05 0940	S	20.48	REMOVE NEW NOX [illegible] ; PUT IN OLD [illegible]

RECEIVED
JUN 1 0 2005
BY: [illegible] 1099

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION **FOR THE *WATSON COGENERATION STEAM AND ELECTRICITY RELIABILITY PROJECT***	Docket No. 09-AFC-1 PROOF OF SERVICE LIST (Revised 9/23/09)

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DECLARATION OF SERVICE

I, Cindy Kyle-Fischer, declare that on November 18, 2009, I shipped by Federal Express from Denver, Colorado copies of the attached, *November 11, 2009 Letter of Response to South Coast Air Quality Management District Questions*, fully prepaid and addressed to the California Energy Commission. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/watson]**.

The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

_X_ sent electronically to all email addresses on the Proof of Service list who indicated "email preferred";

_X_ *by Federal Express from Denver, Colorado, fully prepaid and addressed as provided on the Proof of Service list above to those addresses **NOT** marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

___sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (***preferred method***);

OR

_X_ *by Federal Express one original paper copy and 1 CD, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 09-AFC-1
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

C Kyle-Fischer

______________________:
Cindy Kyle-Fischer

* indicates change