SALT RIVER PROJECT
SANTAN GENERATING STATION

SANTAN EMISSIONS ASSESSMENT REPORT

SL-013399
Rev. 0

Prepared By:

Project No. 12046-021

August 18, 2016

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FOR

SALT RIVER PROJECT

SANTAN GENERATING STATION

SANTAN EMISSIONS ASSESSMENT REPORT

I CERTIFY THAT THIS REPORT WAS PREPARED BY ME OR UNDER MY SUPERVISION AND THAT I AM A REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARIZONA.

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APPROVAL PAGE

FOR

SALT RIVER PROJECT

SANTAN GENERATING STATION

SANTAN EMISSIONS ASSESSMENT REPORT

Rev.	Date/ Purpose	Discipline	Prepared	Reviewed	Approved	Pages Affected
0	08/18/2016 Final	Environmental	J. Rooney	D. Helm	R. Gaikwad	**All**

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ABBREVIATIONS AND ACRONYMS

Abbreviation or Acronym	Explanation
ACC	Arizona Corporation Commission
BACT	Best Available Control Technology
Btu	British thermal unit
C_3H_8	propane
CEC	Certificate of Environmental Compatibility
CEMS	continuous emission monitoring system
CO	carbon monoxide
CO_2	carbon dioxide
CT	combustion turbine
DCS	Distributed control system
DLN	dry low NO_x
EPA	U.S. Environmental Protection Agency
EGU	electric generating unit
GE	General Electric
GHG	greenhouse gas
g/kW-hr	grams per kilowatt-hour
gpm	gallons per minute
gr/ft^3	grains per cubic feet
gr S/100 ft^3	grains of sulfur per 100 cubic feet
HC	hydrocarbon
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
hp	horsepower
hr	hour
HRSG	heat recovery steam generator
in	inches
in. w.c.	inch water column (unit of pressure)
kW	kilowatt
kWh	kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	pound
LHV	lower heating value
mmBtu	million British thermal unit
MCAQD	Maricopa County Air Quality Department
mg/L	milligram per liter

Abbreviation or Acronym	Explanation
MW	megawatt
NGCC	natural gas combined cycle
NH_3	ammonia
NO	nitrogen monoxide
NO_2	nitrogen dioxide
NO_X	nitrogen oxide
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	operations and maintenance
O_2	oxygen
OEM	original equipment manufacturer
^oF	degrees Fahrenheit
PI	plant input
PM	particulate matter
PM_{10}	particulate matter (10 micrometers and smaller)
$PM_{2.5}$	particulate matter (2.5 micrometers and smaller)
ppm	parts per million
ppmvd	parts per million by volume, dry basis
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
S&L	Sargent & Lundy, LLC
SCR	selective catalytic reduction
SGS	Santan Generating Station
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SRP	Salt River Project
ST	steam turbine
TDS	total dissolved solids
tpy	tons per year
VOC	volatile organic compound

EXECUTIVE SUMMARY

Sargent & Lundy, LLC (S&L) has been retained by Salt River Project (SRP) to perform an emissions assessment for the Santan Generating Station (SGS). This assessment has been prepared in accordance with Condition 38 of the Arizona Corporation Commission ("ACC" or Commission) Certificate of Environmental Compatibility (CEC) for the Santan Expansion Project, which was revised under ACC Decision No. 72636 on October 19, 2011. Condition 38 states:

> *Beginning upon commercial operation of the new units, Applicant shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emissions and the costs associated with each potential improvement.*
>
> *Commission Staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 90 days of receipt. Applicant shall install said improvements within 48 months after an order issued by the Commission identifying the specific air emission controls and directing their installation. In the event that new controls or a new operating methodology are required, the in-service date of any new control technology or operating methodology will be the starting date for the next five-year review period.*
>
> *If no new operating methodology is required, the starting date for the next five-year review period shall be the effective date of the Commission's decision regarding the previous five-year review report.*

SGS includes seven (7) gas-fired combined cycle units capable of generating a total of 1,193 MW (nominal) with seasonal variations.

Units 1 through 4 (S-1, S-2, S-3, S-4) each include a GE 7EA combustion turbine (CT), heat recovery steam generator (HRSG), and steam turbine. Units 1 through 4 are capable of generating approximately 368 MW (net). Units 1, 2, and 3 were commissioned in 1974 while Unit 4 was commissioned in 1975. Between 2000 and 2004, emissions control improvements consisting of installation of DLN-1 low NO_X combustors and CO oxidation catalyst to reduce nitrogen oxide (NO_x) and carbon monoxide (CO) emissions were implemented per Conditions 32 and 37 of the Commission's CEC for the Santan Expansion Project issued on May 1, 2001.

The Santan Expansion Project is comprised of Units 5 and 6. Unit 5 (S-5A, S-5B) includes two GE 7FA CTs with low NO_x combustors, two supplementary fired HRSGs with CO and selective catalytic reduction (SCR) catalyst for CO and NO_X control, and one steam turbine (S-5S). Unit 5 was commissioned in 2005. Unit 6 (S-6A) consists of one GE 7FA CT with low NO_x combustors, one HRSG with CO and SCR catalyst for CO and NO_X control, and one steam turbine (S-6S). Unit 6 was commissioned in 2006. Units 5 and 6 are capable of generating nominally 825 MW (net).

In addition to the electric generating units, the following emission sources are installed at the facility: cooling towers, emergency engines, abrasive blasting equipment, and fuel storage tanks.

This evaluation includes information necessary to meet the objectives set forth in Condition 38 of the revised CEC. S&L performed the emissions assessment in two phases; Phase 1 - “Data Collection / Evaluation & Initial Assessments” and Phase 2 – “Development of Emissions Reduction Options.”

The first phase of the evaluation included data collection and initial emissions assessments. S&L conducted an assessment of the current emissions at SGS in order to determine which pollution control technologies should be evaluated in detail. In addition to evaluating emissions from the seven natural gas fired combined cycle generating units (Units S-1, S-2, S-3, S-4, S-5A, S-5B, and S-6A), S&L evaluated emissions from the diesel engines, cooling towers, and abrasive blasting equipment. S&L also visited SGS to meet with plant personnel to understand how various equipment and systems are operated and maintained, and to identify potential operational changes to reduce facility-wide emissions.

Based on the results of the “Phase 1” emissions assessment, S&L concluded that there is potential for reducing CO and NO_x emissions from Units 1-4. Therefore, emissions improvements for Units 1-4 were further evaluated in the “Phase 2” evaluation.

For other SGS emissions sources, improvements were not further evaluated based on the following:

- Units 5-6 are equipped with state-of-the-art emissions control technologies and are currently operating at or below levels generally required for similar, recently permitted facilities, and based on S&L’s engineering judgment, any physical changes to the units would cost well in excess of normal thresholds for cost effectiveness,
- Cooling towers currently include state-of-the-art mist eliminators designed to achieve 0.0005% drift,
- Diesel engine improvements are not practical due to limited annual operation,
- Abrasive blasting equipment is already equipped with a dust collector,
- Gasoline storage tank vapor losses are minimized due to proper tank design, fuel handling procedures, and limited annual gasoline throughput, and, based on S&L’s engineering judgment, modifications to reduce emissions any further, such as employing vapor recovery systems used at high throughput commercial gas stations, would not be cost effective, and
- The key elements of a comprehensive O&M program are utilized at SGS.

The results of the Phase 1 emissions assessment are discussed in detail in Section 4 of the report. A summary of the results of the Phase 1 emissions assessment is provided in Table ES-1 and Table ES-2.

Table ES-1. Summary of Phase 1 Emissions Assessment for Units 1-6 and Cooling Towers

Emission Source		Pollutant					Emissions Improvements Further Evaluated?
		NOx	CO	VOC	PM_{10} / $PM_{2.5}$	SO_2	
Units 1-4	**SGS (Actual)**	**< 20 ppm (normal operation)**	**< 4 ppm (normal operation)**	**~1.7 ppm (reported)** **1.4 ppm (guarantee – 80-100% load)**	**0.0066 lb/mmBtu (reported)** **5 lb/hr (guarantee)**	**Fuel S Content < 0.076 gr/100ft^3**	**Yes - NO_x/CO** **No – VOC/PM/SO_2** ***(Emissions reductions will not be evaluated due to (1) DLN-1 combustors/CO catalyst for VOC, and (2) firing low sulfur fuel and good combustion practices for PM/SO_2)***
	Recent Permit Limits	***2-2.5 ppm (50% to 100% load)***	***0.9-4 ppm (50% to 100% load)***	***0.7-5 ppm (50% to 100% load)***	***0.0033 - 0.014 lb/mmBtu***	***Fuel S Content 0.2-5 gr/ 100ft^3***	
Units 5-6	**SGS (Actual)**	**< 2 ppm**	**< 1 ppm**	**< 1 ppm**	**<0.005 lb/mmBtu**	**Fuel S Content < 0.076 gr/100ft^3**	**No** ***(Emissions reductions will not be evaluated because Units 5-6 are already equipped with state-of-the-art emissions controls and based on S&L's engineering judgment, any changes would cost well in excess of the typical cost thresholds)***
	Recent Permit Limits	***2-2.5 ppm (50% to 100% load)***	***0.9-4 ppm (50% to 100% load)***	***0.7-5 ppm (50% to 100% load)***	***0.0033 - 0.014 lb/mmBtu***	***Fuel S Content 0.2-5 gr/ 100ft^3***	
Cooling Towers	**SGS (Actual)**	**NA**	**NA**	**NA**	**Drift < 0.0005%**	**NA**	**No** ***(Emissions reductions will not be evaluated because SGS cooling tower mist eliminator drift efficiency is less than 0.0005%)***
	Recent Permit Limits	***NA***	***NA***	***NA***	***Drift < 0.0005-0.001%***	***NA***	

Table ES-2. Summary of Phase 1 Emissions Assessment for Balance of Plant Equipment

Emission Source		**Pollutant**					**Emissions Improvements Further Evaluated?**
		NOx	**CO**	**VOC**	**PM_{10} / $PM_{2.5}$**	**SO_2**	
Emergency Diesel Engines	**Fire Pump (310 horsepower [hp]) and Sump Pump Emergency Generator (823 hp) (Actual)**	**9.2 g/kW-hr**	**11.4 g/kW-hr**	**1.3 g/kW-hr**	**0.54 g/kW-hr**	**Fuel S Content < 0.0015 wt%**	**No** ***(Additional emissions control technology is not practical for limited use engines such as emergency generators, and the emissions reductions generated by such controls would be < 0.1 tons per year(tpy), so improvements are not further evaluated because, based on S&L's engineering judgment, the cost effectiveness of such controls would be well in excess of typical cost thresholds)***
	Turning Gear Emergency Generator (577 hp) (Actual)	**4.0 g/kW-hr**	**3.5 g/kW-hr**	**1.3 g/kW-hr (NMHC+NO_x)**			
	Recent Permit Limits	***NOx + NMHC: 4.0 g/kW-hr (310 hp fire pump, 577 hp generator) NOx + NMHC: 6.4 g/kW-hr (823 hp generator)***	***3.5 g/kW-hr (310 hp fire pump, 577/823 hp generators)***	***NOx + NMHC: 4.0 g/kW-hr (310 hp fire pump, 577 hp generator) NOx + NMHC: 6.4 g/kW-hr (823 hp generator)***	***0.20 g/kW-hr (310 hp fire pump, 577/823 hp generators)***	***Fuel S Content < 0.0015 wt%***	
Abrasive Blasting Equipment	**SGS (Actual)**	**NA**	**NA**	**NA**	**Opacity < 20%**	**NA**	**No** ***(Equipped with dust collector that achieves 99.9% PM control)***
	Recent Permit Limits	***NA***	***NA***	***NA***	***Opacity < 20%***	***NA***	
Gasoline Storage Tank	**SGS (Actual)**	**NA**	**NA**	**NA(1)**	**NA**	**NA**	**No** ***(Emissions reductions will not be evaluated because tank design and fuel handling procedures generally meet requirements for similar tanks, and based on S&L's engineering judgment, making any physical changes would be cost prohibitive compared to typical thresholds)***
	Recent Permit Limits for similarly sized tanks	***NA***	***NA***	***NA(1)***	***NA***	***NA***	

(1) VOC emissions from gasoline storage tanks are controlled by utilizing proper tank design (e.g., submerged fill pipe) and fuel handling procedures to minimize vapor losses, and limiting annual fuel throughput.

The "Phase 2" analysis performed for Units 1-4 generally follows a "top-down" approach that is used in permitting new major sources of air emissions or modifications to an existing major source. A similar process has been used by state and county agencies in evaluating NO_x emission controls at existing stationary sources as part of a regional ozone attainment strategy. The top-down approach used in this evaluation includes the following steps for each emission source and pollutant that is being evaluated:

1. Identify potential control technologies.
2. Eliminate technically infeasible control options.
3. Rank the remaining control technologies by control effectiveness.
4. Evaluate the control technologies, starting with the most effective for:
   - economic impacts,
   - environmental impacts, and
   - energy impacts.
5. Summary of potential emissions improvements.

Similar to the 2011 Condition 38 Assessment, the NO_x control technology assessment identified three options that are considered technically feasible and commercially available for control of NO_x emissions from Units 1-4: (1) combustor upgrades, (2) selective catalytic reduction (SCR) systems, and (3) SCR systems with combustor upgrades. No new NO_X control technologies were discovered to be feasible for Units 1-4. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness of available NO_X control technologies ranges from approximately $26,968 per ton (combustor upgrades) to $70,651 per ton (SCR + combustor upgrades)[1].

EPA has not defined a cost threshold at which NO_x control technologies for existing power plants are considered "cost effective." Cost effectiveness thresholds are typically set at the discretion of regulating agencies on a project-specific basis. However, based on a review of publicly available documents, it is common for agencies to consider the "cost prohibitive" threshold for NO_x control options to range between $5,000 and $10,000 per ton NO_x removed for the retrofit of control technology on gas-fired electric generating units (see Attachment 10 for a table of reference documents). Therefore, based on the range of costs identified for SGS Units 1-4 NO_x control options, NO_x emissions improvements for SGS Units 1-4 would be considered cost prohibitive. A summary of the Phase 2 NO_x emissions assessment for Units 1-4 is presented in Table ES-3.

[1] The S&L assessment from 2011 estimated the average cost effectiveness range for NO_X control to be $22,104 per ton (combustor upgrades) to $74,369 per ton (SCR + combustor upgrades).

Table ES-3. Summary of NO_x Control Evaluation for Units 1-4[(1)]

Control Technology	Total Emissions Reduction (tpy)	Total Capital Cost ($)	Total Annual O&M Cost ($/year)	Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)
SCR + Combustor Upgrades	**145.4[(2)]**	**$80,824,000**	**$2,228,000**	**$10,276,000**	**$70,651**
SCR	**145.4**	**$57,448,000**	**$1,995,000**	**$7,715,000**	**$53,043**
Combustor Upgrades	**97.0**	**$23,376,000**	**$287,000**	**$2,615,000**	**$26,968**
Baseline Combustion Controls (DLN-1 Combustors)	**NA**	**NA**	**NA**	**NA**	NA

(1) Values presented in table are combined totals for SGS Units 1-4.
(2) The total NO_X emissions reduction is equivalent for the SCR and SCR + combustor upgrades options. For both options, the lowest achievable NO_X emission rate would be 2 ppm. The SCR + combustor upgrades options would have a lower NO_X emission rate at the SCR inlet compared to the SCR only upgrade.

Similar to the 2011 Condition 38 Assessment, the CO control technology assessment identified three options that are considered technically feasible and commercially available for control of CO emissions from Units 1-4: (1) combustor upgrades, (2) upgraded oxidation catalyst system, and (3) upgraded oxidation catalyst system with combustor upgrades. No new CO control technologies were discovered to be feasible for Units 1-4. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness of available CO control technologies ranges from approximately $16,639 per ton (CO catalyst upgrades) to $651,381 per ton (CO catalyst + combustor upgrades).[2]

EPA has not defined a cost threshold at which CO control technologies for existing power plants are considered "cost effective." Cost effectiveness thresholds are typically set at the discretion of regulating agencies on a project-specific basis. However, based on a review of publicly available documents, it is common for agencies to consider CO control options "cost prohibitive" at levels

[2] The S&L assessment from 2011 estimated the average cost effectiveness range for CO control to be $63,895 per ton (combustor upgrades) to $464,694 per ton (SCR + combustor upgrades).

exceeding $4,000 per ton CO removed (see Attachment 10 for a table of reference documents). Therefore, based on the range of costs identified for SGS Units 1-4 CO control options, CO emissions improvements for SGS Units 1-4 would be considered cost prohibitive. A summary of the Phase 2 CO emissions assessment for Units 1-4 is presented in Table ES-4.

Table ES-4. Summary of CO Control Evaluation for Units 1-4(1)

Control Technology	Total Emissions Reduction (tpy)	Total Capital Cost ($)	Total Annual O&M Costs ($/year)	Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)
CO Catalyst System Upgrades	**20.07**	**$1,361,000**	**$198,000**	**$334,000**	**$16,639**
CO Catalyst System Upgrades and Combustor Upgrades	**20.07(2)**	**$24,737,000**	**$485,000**	**$2,949,000**	**$146,916**
Combustor Upgrades and Existing CO Catalyst System	**4.01**	**$23,376,000**	**$287,000**	**$2,615,000**	**$651,381**
Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System	**NA**	**NA**	**NA**	**NA**	**NA**

(1) Values presented in table are combined totals for SGS Units 1-4.
(2) The total CO emissions reduction is equivalent for the CO catalyst and CO catalyst + combustor upgrades options. For both options, the lowest achievable CO emission rate would be 2 ppm. The CO catalyst + combustor upgrades options would have a lower CO emission rate at the CO catalyst inlet compared to the CO catalyst only upgrade.

Based on the average cost effectiveness of technically feasible control options compared to the cost effectiveness thresholds, we recommend that SRP not add any additional NO_x or CO emission controls to SGS Units 1-4 at this time. The installation of new NO_X and CO control technologies on SGS Units 1-4 would be cost prohibitive.

1 INTRODUCTION

Sargent & Lundy, LLC (S&L) has been retained by Salt River Project (SRP) to perform an emissions assessment for the Santan Generating Station (SGS). This assessment has been prepared in accordance with Condition 38 of the Arizona Corporation Commission's (ACC) Certificate of Environmental Compatibility (CEC) for the Santan Expansion Project issued on May 1, 2001 (see Attachment 1). The previous emissions assessment report was filed by SRP on July 1, 2011. SRP requested an ACC order stating that no additional air emission controls were required at SGS at the time of the 2011 report. The final order did not require installation of any improvements at the Santan Generating facility and was approved on October 14, 2011.

As a result of the previous emissions assessment report, the Commission agreed to revise Condition 38 based on comments from SRP (See Attachment 2: Decision No. 72636, October 14, 2011). The revised Condition 38 states:

> *Beginning upon commercial operation of the new units, Applicant shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emissions and the costs associated with each potential improvement.*
>
> *Commission Staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 90 days of receipt. Applicant shall install said improvements within 48 months after an order issued by the Commission identifying the specific air emission controls and directing their installation. In the event that new controls or a new operating methodology are required, the in-service date of any new control technology or operating methodology will be the starting date for the next five-year review period.*
>
> *If no new operating methodology is required, the starting date for the next five-year review period shall be the effective date of the Commission's decision regarding the previous five-year review report.*

This evaluation includes information necessary to meet the objectives set forth in Condition 38 of the CEC. Information is presented in the following sections:

Section 2 – Facility Description contains information describing SGS and emissions sources considered in the evaluation.

Section 3 – The Evaluation Process provides a description of the steps that were included in the review of the facility's operations and equipment with respect to identifying potential improvements that would reduce plant emissions.

Section 4 – Phase 1 Evaluation: Current Emissions provides a description of current plant wide emissions and identifies potential emissions improvements.

Section 5 – Phase 2 Evaluation: Emissions Reduction Options presents an evaluation of potential control options and associated costs with options that are deemed technically feasible.

Section 6 – Conclusion identifies potential emissions improvements for SGS.

2 FACILITY DESCRIPTION

The Santan Generating Station is located at 1005 South Val Vista Drive, Gilbert, Arizona. The Facility operates under a Title V Air Quality Permit, No. V95-008, dated September 21, 2015 ("Permit") and has a total of seven (7) electric generating units (EGU).

Units 1 through 4 (S-1, S-2, S-3, S-4) each include a GE 7EA combustion turbine (CT) with dry low NO_X (DLN-1) combustors for nitrogen oxide (NO_X) control, heat recovery steam generator (HRSG), and CO oxidation catalyst for carbon monoxide (CO) control. Units 1 through 4 are capable of generating approximately 368 megawatts (MW) (net). Units 1, 2, and 3 were commissioned in 1974 while Unit 4 was commissioned in 1975. Emissions control improvements consisting of installation of DLN-1 combustors and CO oxidation catalyst to reduce NO_x and CO emissions were implemented between 2000 and 2004. These emissions control improvements were implemented per Conditions 32 and 37 of the ACC's CEC for the Santan Expansion Project issued on May 1, 2001.

The Santan Expansion Project is comprised of Units 5 and 6. Unit 5 (S-5A, S-5B) consists of two GE 7FA CTs with low-NO_x combustors, two HRSGs with CO and selective catalytic reduction (SCR) catalyst for CO and NO_X control, and one steam turbine (S-5S). Unit 5 was commissioned in 2005. Unit 6 (S-6A) consists of one GE 7FA CT with low-NO_x combustors, one HRSG with CO and SCR catalyst for CO and NO_X control, and one steam turbine (S-6S). Unit 6 was commissioned in 2006. Units 5 and 6 are capable of generating nominally 825 MW (net).

In addition to the electric generating units, the following emission sources are installed at the facility:

- Cooling Towers (CT1, CT5, and CT6)
  - CT1: One 101,500 gallon per minute (gpm) mechanical draft, cross flow cooling tower, in operation since 1973
  - CT5: One 172,923 gpm mechanical draft, counter flow cooling tower, in operation since 2004
  - CT6: One 80,755 gpm mechanical draft, counter flow cooling tower, in operation since 2005
- Emergency Engines
  - One 310 horsepower (hp) diesel-fired emergency fire water pump certified to meet Environmental Protection Agency (EPA) Tier 1 emissions standards, in operation since 2004
  - One 823 hp diesel-fired emergency generator certified to meet EPA Tier 1 emissions standards, in operation since 2004
  - One 577 hp diesel-fired emergency generator certified to meet Tier 3 emissions standards, in operation since 2008
  - One 122 hp propane-fired emergency generator, in operation since 2008

- Abrasive Blasting Equipment
    - Abrasive blasting building, in operation since 1978
- Fuel Storage Tanks
    - One 500 gallon gasoline storage tank
    - Three diesel fuel storage tanks (two 500 gallon, one 350 gallon)

3 THE EVALUATION PROCESS

S&L performed the emissions assessment in two phases; Phase 1 - "Data Collection / Evaluation & Initial Assessments" and Phase 2 – "Development of Emissions Reduction Options." Based on the results of Phases 1 and 2, S&L developed a list of potential emissions improvements for SGS. A brief description of each phase of this assessment is provided below.

Phase 1 – Data Collection / Evaluation & Initial Assessments

The first phase included data collection and an initial emissions assessment. S&L reviewed both current and historical emissions information from plant data collection systems (e.g., distributed control system [DCS], plant input [PI], and continuous emission monitoring system [CEMS]). In addition, the Title V Permit was reviewed to identify regulated emission units and respective emission limits. The information provided for the "Phase 1" assessment was processed and compared with emissions limits that have been included in recently issued permits for similar new sources. This comparison identified the SGS emissions units that were further evaluated in "Phase 2."

In conjunction with the data collection and review process, S&L also evaluated how the plant has been operated and maintained to determine if changes to O&M practices could affect emissions as well. S&L visited SGS to meet with plant personnel to understand how various equipment and systems are operated and maintained, and to identify potential operational changes to reduce facility-wide emissions.

Phase 2 – Development of Emissions Reduction Options

The second phase included an evaluation of potential emissions improvements for sources identified in Phase 1. This assessment included a discussion of potential emissions control options and an estimate of costs associated with such options.

Potential Emissions Improvements

Based on the results of the Phase 1 and Phase 2 evaluations, S&L identified potential emissions improvements that could be implemented at SGS.

4 PHASE 1 EVALUATION: CURRENT EMISSIONS

S&L conducted an assessment of the emissions at SGS in order to determine which pollution control technologies should be evaluated in detail. In addition to the seven EGUs, S&L evaluated emissions from the diesel engines, cooling towers, and abrasive blasting equipment. Pollutants that were evaluated included NO_X, CO, volatile organic compounds (VOC), particulate matter (10 micrometers and smaller) (PM_{10})/ particulate matter (2.5 micrometers and smaller) ($PM_{2.5}$), and sulfur dioxide (SO_2).

4.1 UNITS 1, 2, 3 & 4

Units 1-4 (S-1, S-2, S-3, and S-4) each include a GE 7EA CT and HRSG. Units 1, 2, and 3 began operation in 1974 while Unit 4 began operating in 1975. In 2001 and 2003, combustor modifications and installation of oxidation catalyst on Units 1 through 4 resulted in NO_x, CO, and VOC emissions reductions.

The Permit includes annual emission limits for Units 1-4. Based on review of the facility's annual emissions inventories from 2013 to 2015 that were submitted to the Maricopa County Air Quality Department (MCAQD), emissions from Units 1-4 have been significantly less than the respective annual permit limits (see Table 4-1).

Table 4-1. Units 1-4 Annual Emissions Limits and Reported Emission Rates

Pollutant	Permit Limit (tons per year)	Reported Emissions between 2013 and 2015 (tons per year)
NO_X	1056.0	161.6 (2013) 114.5 (2014) 126.5 (2015)
CO	174.0	40.1 (2013) 26.7 (2014) 23.0 (2015)
SO_2	22.48	1.0 (2013) 0.7 (2014) 0.9 (2015)
VOC	33.68	3.5 (2013) 2.4 (2014) 3.3 (2015)
$PM_{10}/PM_{2.5}$	105.88	10.9 (2013) 7.5 (2014) 10.3 (2015)

Note: The emission limits and reported emissions are combined for Units 1, 2, 3, and 4.

In addition to evaluating annual emissions, S&L also performed an evaluation of short-term emissions from Units 1-4. The following sections provide a pollutant-by-pollutant evaluation of current short-term emissions.

4.1.1 NO_x Emissions

Permit Condition 18.c.iii.1 states that Units 1-4 shall not emit NO_x in excess of 155 parts per million by volume, dry basis (ppmvd) @ 15% oxygen (O_2) as demonstrated by the arithmetic mean of the results of three test runs during steady state operations while firing natural gas.

S&L's review of emissions inventories and compliance test reports submitted to MCAQD, along with discussions with SRP personnel, indicate that Units 1-4 are operating in accordance with permit requirements.

In 2001, SRP replaced the original Units 1-4 combustors with DLN-1 combustors. The DLN-1 combustors were guaranteed to achieve NO_x values of 20 ppmvd @ 15% O_2 while operating from 80 to 100% load. Based on review of NO_x CEMS data, Units 1-4 are generally achieving less than 20 ppm NO_x at full load.

Recent NO_x control technology developments have enabled units to achieve NO_x levels below those currently achieved by Units 1-4. For example, DLN combustor technology has matured and DLN systems installed on new combustion turbines have demonstrated the ability to achieve NO_x levels below 10 ppmvd @ 15% O_2 during "normal" operation (i.e., loads above approximately 50%). In addition, post-combustion control technologies, namely SCR, could be used to further reduce NO_x emissions. Based on a review of potentially available NO_x control systems, improvements may be available to reduce NO_x emissions from Units 1-4. Therefore, potential NO_x reduction methods are evaluated in Section 5 of this report.

4.1.2 CO Emissions

Permit Condition 18.c.ii states that Units 1-4 shall not emit CO in excess of 400 ppmvd @ 15% O_2 at any time. S&L's review of emissions inventories and compliance test reports submitted to MCAQD, along with discussions with SRP personnel, indicate that Units 1-4 are operating in accordance with permit requirements.

The DLN-1 combustors installed in 2001 were guaranteed to meet a CO level of 10 ppmvd while operating from 80 to 100% load. In 2003, SRP further reduced CO emissions from Units 1-4 with the installation of CO catalyst at the CT plenum outlet. The CO catalyst was designed to achieve a stack emission rate of 4 ppm while operating from 80 to 100% load. The CO catalyst was replaced in 2013 on all four units. Based on review of CO CEMS data, Units 1-4 are generally achieving less than 4 ppm CO at full and mid loads.

Although oxidation catalyst is currently installed on Units 1-4 for CO reduction, further reductions could potentially be achieved with the installation of additional catalyst. Based on a review of potentially available CO control systems, improvements may be available to reduce CO emissions from Units 1-4. Therefore, potential CO emissions improvements for Units 1-4 are evaluated in Section 5 of this report.

4.1.3 VOC Emissions

The DLN-1 combustors installed in 2001 were guaranteed to achieve a VOC level of 1.4 ppmv while operating from 80 to 100% load. As discussed in Section 4.1.2, SRP installed oxidation catalyst at the CT plenum outlet for Units 1-4 in 2003. Even though the CO catalyst vendor did not provide VOC reduction guarantees, it is likely that the oxidation catalyst systems currently installed on Units 1-4 are reducing VOC emissions below the DLN-1 combustor guarantee of 1.4 ppmv while operating from 80 to 100% load.

Based on a review of recent permits that have been issued for new combined cycle units, most units are subject to VOC emissions limits ranging from 1 to 5 ppmvd @ 15% O_2. For Units 1-4, it is likely that VOC emissions are already within this range due to the combination of DLN-1 combustors that are guaranteed to meet 1.4 ppmv and oxidation catalyst systems that are expected to further reduce VOC emissions. Although improvements to the existing oxidation catalyst systems may be available to provide additional CO emissions reductions, it is unlikely that these improvements would provide any significant reduction in VOC emissions. Therefore, VOC emissions improvements for Units 1-4 will not be evaluated at this time.

4.1.4 SO_2 Emissions

Emissions of SO_2 from combustion turbines are a result of oxidation of fuel sulfur. SGS Units 1-4 are designed to fire natural gas. Table 4-2 shows the applicable fuel sulfur content permit limits and actual values obtained from fuel sample data and fuel contracts.

Table 4-2. Units 1-4 Fuel Sulfur Content Permit Limits and Actual Values

Fuel	Permit Limit	Actual Fuel Sulfur Content[1]
Natural Gas	**0.5 grains of sulfur per 100 cubic feet (gr S/100ft^3)**	**< 0.076 gr S/100ft^3**

Note 1: Information obtained from 2014 and 2015 monthly natural gas fuel analyses.

Post combustion SO_2 control systems would have no practical application to natural gas-fired combined cycle units. The only practical method for controlling SO_2 emissions from combined cycle units is the use of low sulfur fuels. Due to the inherently low sulfur content in natural gas, gas firing is the most practical method for minimizing SO_2 emissions.

Based on a review of recent permits that have been issued for new combined cycle units, SO_2 emissions have been minimized with the use of natural gas. Furthermore, there are no post-combustion SO_2 control technologies, or other improvements, available to further reduce SO_2 emissions from Units 1-4. Because Units 1-4 only fire natural gas, SO_2 emissions improvements for Units 1-4 will not be evaluated at this time.

4.1.5 $PM_{10}/PM_{2.5}$ Emissions

The DLN-1 combustors installed in 2001 were guaranteed to achieve a PM emission rate of 5 pound per hour (lb/hr). Per the Permit, a demonstration of compliance with the PM_{10} limit (filterable and condensable particulate matter) can be used as a surrogate for demonstrating compliance with the $PM_{2.5}$ limit.

SGS Units 1-4 are designed to fire natural gas, which is an inherently clean fuel. $PM_{10}/PM_{2.5}$ emissions from natural gas combustion are significantly less than emissions associated with liquid or solid fuel firing. Original equipment manufacturers (OEMs) generally contend that the reported $PM_{10}/PM_{2.5}$ emissions levels are not due to the combustion of natural gas, but instead, reported $PM_{10}/PM_{2.5}$ can be attributed to sampling error, construction debris, suspended $PM_{10}/PM_{2.5}$ in ambient air that passes through CT inlet air filters, and metallic rust or oxidation products.

Post combustion $PM_{10}/PM_{2.5}$ control systems would have no practical application to natural gas-fired combined cycle units. The only practical methods for controlling PM emissions from combined cycle units are: (1) use of natural gas, (2) good combustion practices, and (3) following recommended operations and maintenance (O&M) procedures.

S&L evaluated the SGS O&M records and determined that SRP is following recommended procedures to adequately reduce non-combustion related $PM_{10}/PM_{2.5}$ emissions from Units 1-4 (see Section 4.6).

Based on a review of recent permits that have been issued for new combined cycle units, PM_{10} emissions limits have been based on firing clean fuels and good combustion practices. Furthermore, there are no post-combustion $PM_{10}/PM_{2.5}$ control technologies, or other improvements, available to further reduce $PM_{10}/PM_{2.5}$ emissions. For Units 1-4, $PM_{10}/PM_{2.5}$ emissions are minimized due to the combustion of natural gas and following recommended unit operation and maintenance practices. Therefore, $PM_{10}/PM_{2.5}$ emissions improvements for Units 1-4 will not be evaluated at this time.

4.2 UNITS 5A, 5B & 6A

The CEC for the Santan Expansion Project includes the ACC's conditions for approval of the construction of Units 5 and 6 (S-5A, S-5B, S-6A). Included in the CEC is the following Condition 35:

> *The Santan Expansion Project shall be required to meet the lowest achievable emission rate (LAER) for carbon monoxide (CO), nitrogen oxides (NO_x), volatile organic carbons (VOCs), and particulate matter (PM) less than 10 micron in aerodynamic diameter (PM_{10}). The Santan Expansion Project shall be required to submit an air quality permit application requesting this LAER to the Maricopa County Environmental Services Department.*

Units 5-6 each include a GE 7FA CT and a HRSG. Units 5A and 5B were commissioned in 2005 while Unit 6A was commissioned in 2006. The Units 5A and 5B HRSGs are each equipped with 530 million British thermal units per hour (mmBtu/hr) lower heating value (LHV) supplemental duct burners. The Unit 6 HRSG is equipped with a 490 mmBtu/hr (LHV) supplemental duct burner. In order to meet Lowest Achievable Emission Rate (LAER) requirements for NO_x, CO and VOC, the units are equipped with SCR for NO_x control and oxidation catalyst for CO and VOC control. LAER for PM_{10} is achieved by firing natural gas exclusively.

The Permit includes annual emission limits for Units 5-6. Based on a review of the facility's 2013 through 2015 annual emissions inventories submitted to MCAQD, actual emissions from Units 5-6 have been below the respective annual permit limits (see Table 4-3).

Table 4-3. Units 5-6 Annual Emissions Limits and Reported Emission Rates

Pollutant	Permit Limit tons per year (tpy)	Reported Emissions from 2013 through 2015 (tpy)
NO_X	212.8	93.4 (2013) 97.2 (2014) 106.1 (2015)
CO	304.1	52.4 (2013) 73.8 (2014) 16.0 (2015)
SO_2	34.8	5.8 (2013) 5.9 (2014) 7.3 (2015)
VOC	59.8	3.1 (2013) 4.5 (2014) 5.7 (2015)
$PM_{10}/PM_{2.5}$	170.3	47.8 (2013) 34.3 (2014) 41.2 (2015)

Note: The emission limits and reported emissions are combined for Units 5A, 5B, and 6A.

In addition to evaluating annual emissions, S&L also performed an evaluation of short-term emissions from Units 5-6. The following sections provide a pollutant-by-pollutant evaluation of current short-term emissions.

4.2.1 NO_x Emissions

The Permit includes a NO_X concentration limit of 2 ppmvd @ 15% O_2 on a 1-hour averaging basis for Units 5A, 5B, and 6A. In addition, Units 5-6 are subject to EPA's New Source Performance Standards (NSPS) Subparts GG and Da. NSPS Subpart GG states that the combustion turbine NO_x emissions shall not exceed approximately 75 ppmvd @15% O_2.[3] NSPS Subpart Da states that the Units 5-6 duct burners NO_x emissions shall not exceed 1.6 pound per megawatt-hour (lb/MWh) on a 30-day rolling average basis based on the average emission rate for 30 successive boiler operating days.

[3] The NSPS Subpart GG NOx emissions limit is estimated based on the equation identified in Permit Condition 18.b.ii.1.

To meet the applicable NO_x emissions limits, each unit is equipped with low NO_x combustors and an SCR system. S&L's review of emissions inventories and compliance certifications, along with discussions with SRP personnel, indicate that Units 5A, 5B, and 6A are operating in accordance with permit requirements. Based on a review of recent permits that have been issued for new combined cycle units, most units are subject to NO_x emissions limits ranging from 2 to 2.5 ppmvd @ 15% O_2 (see Attachment 3). Units 5A, 5B, and 6A include combustors and duct burners that are designed to achieve low NO_x emissions and an SCR system that enables the units to meet the most stringent NO_x levels required for new units. Therefore, NO_x emissions improvements for Units 5-6 will not be evaluated at this time.

4.2.2 CO Emissions

Units 5A, 5B, and 6A are required to meet a CO concentration limit of 2.0 ppmvd @ 15% O_2 on a 3-hour rolling average basis. To meet this limit, each unit is equipped with an oxidation catalyst system. S&L's review of emissions inventories and compliance certifications, along with discussions with SRP personnel, indicate that Units 5A, 5B, and 6A are operating in accordance with permit requirements.

Based on a review of recent permits that have been issued for new combined cycle units, most units are subject to CO emissions limits ranging from 2 to 4 ppmvd @ 15% O_2 (see Attachment 3), and the lowest CO emissions limits range from 0.9 to 2 ppmvd @ 15% O_2. Units 5A, 5B, and 6A include combustors and duct burners designed to achieve low CO emissions and oxidation catalyst that enables the units to meet CO levels required for new units. While upgrades to the Units' existing CO catalyst are possible, based on S&L's engineering judgment, the costs associated with those modifications would outweigh the reductions that would be achieved. Therefore, CO emissions improvements for Units 5-6 will not be evaluated at this time.

4.2.3 VOC Emissions

Units 5A, 5B, and 6A are required to meet a VOC concentration limits of 1.0 ppmvd @ 15% O_2 (without duct firing) and 2.0 ppmvd @ 15% O_2 (with duct firing), on a 3-hour rolling average basis. The oxidation catalyst systems that are installed for CO reduction also reduce VOC emissions. S&L's review of stack test data and compliance certifications, along with discussions with SRP personnel, indicate that Units 5A, 5B, and 6A are operating in accordance with permit requirements. For example, 2015 stack test results for Unit 5A, 5B, and 6A with duct burners on show that VOC emissions range from 0.17 ppm to 0.22 ppm as propane (C_3H_8) @ 15% O_2.

Based on a review of recent permits that have been issued for new combined cycle units, several units are subject to Best Available Control Technology (BACT) VOC emissions limits ranging from 1 to 5 ppmvd @ 15% O_2 (see Attachment 3), and LAER VOC emissions limits ranging from 0.7 to 1.9 ppmvd @ 15% O_2. Units 5A, 5B, and 6A include combustors and duct burners designed to achieve low VOC emissions and oxidation catalyst that enable the units to meet VOC levels required for new units. While modifications to reduce VOC emissions exist, such as modifications to the CO catalyst, based on S&L's engineering judgment, the costs associated with those modifications would outweigh the reductions that would be achieved. Therefore, VOC emissions improvements for Units 5-6 will not be evaluated at this time.

4.2.4 SO_2 Emissions

Emissions of SO_2 from combustion turbines are a result of oxidation of fuel sulfur. SGS Units 5A, 5B, and 6A are designed to fire natural gas exclusively. Table 4-4 shows the applicable fuel sulfur content permit limits and actual values obtained from fuel sample data and fuel contracts. In addition, Units 5-6 are subject to SO_2 standards found in NSPS Subparts GG and Da. NSPS Subpart GG states that combustion turbine SO_2 emissions shall not exceed 0.015% by volume at 15% O_2 on a dry basis, and the fuel sulfur content shall not exceed 0.8% by weight. NSPS Subpart Da states that SO_2 emissions from the duct burners shall not exceed 100% of the potential combustion concentration.

Table 4-4. Units 5-6 Fuel Sulfur Content Permit Limits and Actual Values

Fuel	Permit Limit	Actual Fuel Sulfur Content
Natural Gas	**0. 5 gr S/100ft^3**	**< 0.076 gr S/100ft^3**

The only practical method for controlling SO_2 emissions from combined cycle units is the use of low sulfur fuels. Due to the inherently low sulfur content in natural gas, gas firing is the most practical method for minimizing SO_2 emissions. Based on a review of recent permits that have been issued for new combined cycle units, SO_2 emissions have been minimized with the use of natural gas. Furthermore, there are no post-combustion SO_2 control technologies, or other improvements, available to further reduce SO_2 emissions from Units 5A, 5B, or 6A. Because Units 5A, 5B, and 6A only fire natural gas, SO_2 emissions improvements for Units 5-6 will not be evaluated at this time.

4.2.5 $PM_{10}/PM_{2.5}$ Emissions

Units 5A, 5B, and 6A are required to meet a $PM_{10}/PM_{2.5}$ emission limit of 0.01 pound per million British thermal unit (lb/mmBtu) (with and without duct firing).

S&L's review of stack test data and compliance certifications, along with discussions with SRP personnel, indicate that Units 5A, 5B, and 6A are operating in accordance with permit requirements. For example, 2015 stack test results for Units 5A, 5B, and 6A with duct burners on show that PM_{10} emissions range from 0.0038 and 0.0049 lb/mmBtu. Per the Permit, a demonstration of compliance with the PM_{10} limit (filterable and condensable particulate matter) can be used as a surrogate for demonstrating compliance with the $PM_{2.5}$ limit.

SGS Units 5-6 are designed to fire natural gas, which is an inherently clean fuel. $PM_{10}/PM_{2.5}$ emissions from natural gas combustion are significantly less than emissions associated with liquid or solid fuel firing. OEMs generally contend that the reported $PM_{10}/PM_{2.5}$ emissions levels are not due to the combustion of natural gas, but instead, reported $PM_{10}/PM_{2.5}$ can be attributed to sampling error, construction debris, suspended $PM_{10}/PM_{2.5}$ in ambient air that passes through CT inlet air filters, and metallic rust or oxidation products.

Post combustion $PM_{10}/PM_{2.5}$ control systems would have no practical application to combined cycle units. SGS Units 5-6 are designed to fire natural gas exclusively, which is an inherently clean fuel. The only practical methods for controlling PM emissions from combined cycle units are: (1) use of natural gas, (2) good combustion practices, and (3) following recommended O&M procedures.

S&L evaluated the SGS O&M records and determined that SRP is following recommended procedures to adequately reduce non-combustion related PM_{10} emissions from Units 5-6 (see Section 4.6).

Based on a review of recent permits that have been issued for new combined cycle units, PM_{10} emissions limits have ranged from 0.0033 to 0.014 lb/mmBtu based on firing clean fuels and good combustion practices. Furthermore, there are no post-combustion PM_{10} control technologies, or other improvements, available to further reduce $PM_{10}/PM_{2.5}$ emissions. For Units 5-6, $PM_{10}/PM_{2.5}$ emissions are minimized due to the combustion of natural gas and following recommended unit operation and maintenance practices. Therefore, $PM_{10}/PM_{2.5}$ emissions improvements for Units 5-6 will not be evaluated at this time.

4.3 COOLING TOWERS

SGS has three cooling towers that dissipate heat from the condensing water for each of the three steam turbines. Cooling Tower CT1 serves the Units 1-4 steam turbine, and Cooling Tower CT5 and CT6 serve the Units 5 and 6 steam turbines, respectively. Table 4-5 provides information for each cooling tower.

Table 4-5. Cooling Tower Design Parameters

Emission Unit	Units Served	Year in Service	Circulating Water Flow Rate (gpm)	Design Mist Eliminator Drift Efficiency(1)
Cooling Tower CT1	**S-1, S-2, S-3, S-4**	**1973**	**101,500**	**< 0.0005%**
Cooling Tower CT5	**S-5A, S-5B**	**2005**	**175,000**	**< 0.0005%**
Cooling Tower CT6	**S-6A**	**2006**	**80,000**	**< 0.0005%**

(1) Mist eliminator efficiency is measured as a percentage of the circulating water flow rate.

$PM_{10}/PM_{2.5}$ from cooling towers is generated by the presence of solids in the cooling tower circulating water, which is potentially emitted as “drift” or moisture droplets that are suspended in the air that is blown through the cooling tower. A portion of the water droplets emitted from the tower exhausts will evaporate, thereby resulting in $PM_{10}/PM_{2.5}$ emissions.

PM_{10} emissions from cooling towers are controlled by the use of high efficiency drift eliminators, reduced number of cycles of concentration, or a combination of both. The cycles of concentration are limited by water availability; lower circulating water concentrations require increased blowdown frequency and thus more makeup water.

The Permit includes limits for circulating water total dissolved solids (TDS) values, mist eliminator drift efficiency, and $PM_{10}/PM_{2.5}$ emissions. As part of the initial emissions assessment, S&L reviewed cooling tower design parameters, reported emission rates, and operating data and compared this information with the respective permit limits. As indicated in Table 4-5 and Attachment 4, the cooling tower mist eliminators are designed to achieve less than 0.0005% drift. Tables 4-6 and 4-7 show that the SGS cooling tower emissions and TDS values are less than the respective permit limits.

Table 4-6. Cooling Tower Annual $PM_{10}/PM_{2.5}$ Emissions Limits and Reported Values

Emission Unit	Permit Limit (tpy)	Reported Values from 2013 to 2015 (tpy)
Cooling Tower CT1	3.3	0.57 (2013) 0.54 (2014) 0.50 (2015)
Cooling Tower CT5	3.5	1.64 (2013) 1.72 (2014) 1.98 (2015)
Cooling Tower CT6	1.6	0.60 (2013) 0.80 (2014) 0.78 (2015)

Table 4-7. Cooling Tower TDS Content Limits and Actual Values

Emission Unit	Permit Limit milligram per liter (mg/L)	Maximum Recorded Values for 2013-2015 (mg/L)
Cooling Tower CT1	**9,500**	**3,500**
Cooling Tower CT5	**5,700**	**3,900**
Cooling Tower CT6	**5,700**	**4,100**

In addition to reviewing operating and emissions data, S&L also reviewed SGS O&M procedures and inspection reports pertaining to the cooling towers. S&L concludes that SRP's O&M records are complete and that an adequate inspection program is in place (see Section 4.2.4 and Attachment 5).

Based on a review of recent permits that have been issued for new cooling towers, $PM_{10}/PM_{2.5}$ emissions have generally been controlled by utilizing mist eliminators designed to achieve 0.0005% drift efficiency. Furthermore, there are no additional PM_{10} controls, or other improvements, capable of providing further $PM_{10}/PM_{2.5}$ emissions reductions from the existing cooling towers. Because SRP utilizes mist eliminators that are designed to achieve 0.0005% drift, $PM_{10}/PM_{2.5}$ emissions improvements for CT1, CT5, and CT6 will not be evaluated at this time.

4.4 DIESEL ENGINES

The following emergency engines are installed at Santan Generating Station:

- One 310 hp diesel-fired emergency fire water pump engine (Fire Pump)
- Two diesel-fired emergency generators, rated at 823 hp (Sump Pump Emergency Generator) and 577 hp (Turning Gear Emergency Generator)
- One 122 hp propane-fired emergency generator (Switchyard Propane Emergency Generator)

Per Permit Condition 19.h, an emergency for the engines is defined as "when normal power line or natural gas service fails, for the emergency pumping of water, for when low water pressure in the fire suppression system is triggered, for unforeseen flood or fire or life threatening situation, or for similar situations accepted as an emergency by the Control Officer and Administrator."

As required by the Permit, the diesel engines are designed to meet the applicable US EPA emissions standards. Permit limits pertaining to the diesel engines are shown in Table 4-8.

Table 4-8. Diesel Engine Permit Limits

Parameter	Fire Pump and Sump Pump Emergency Generator		Turning Gear Emergency Generator	
	Current Title V Permit Limit	Compliance Method	Current Title V Permit Limit	Compliance Method
Hours of Operation	<= 37.5 hr/yr for engine testing, each	Engines operate less than 37.5 hr/yr	<= 100 hr/yr for engine testing, each	Engines operate less than 100 hr/yr
NO_X	9.2 g/kW-hr	Engines meet EPA Tier 1 standard	4.0 g/kW-hr	Engines meet EPA Tier 3 standard
CO	11.4 g/kW-hr	Engines meet EPA Tier 1 standard	3.5 g/kW-hr	Engines meet EPA Tier 3 standard
SO_2	Fuel S content = 0.0015 wt%	Engines fire ultra-low sulfur diesel fuel (fuel S content ≤ 0.0015 wt%)	Fuel S content = 0.0015 wt%	Engines fire ultra-low sulfur diesel fuel (fuel S content ≤ 0.0015 wt%)
VOC	1.3 g/kW-hr	Engines meet EPA Tier 1 standard	1.3 g/kW-hr ($NMHC+NO_x$)	Engines meet EPA Tier 3 standard
$PM_{10}/PM_{2.5}$	0.54 g/kW-hr	Engines meet EPA Tier 1 standard	0.54 g/kW-hr	Engines meet EPA Tier 3 standard

EPA is requiring new, recently permitted emergency diesel engines to meet more stringent NSPS Subpart IIII emissions limits. The NSPS Subpart IIII standards that would apply to new emergency diesel generators and stationary fire pump engines are provided in Table 4-9.

Table 4-9. Comparison of Emergency Diesel Engine Standards

Pollutant	SGS Permit Limits for Fire Pump (310 hp) and Sump Pump Emergency Generator (823 hp)	SGS Permit Limits for Turning Gear Emergency Generator (577 hp)	NSPS Subpart IIII Standards for New Emergency Generators and Fire Pumps (2,3)
NO_X + NMHC	10.5 g/kW-hr(1)	4.0 g/kW-hr	4.0 g/kW-hr (for 310 hp fire pump and 577 hp engine) 6.4 g/kW-hr (for 823 hp engine)
CO	11.4 g/kW-hr	3.5 g/kW-hr	3.5 g/kW-hr
$PM_{10}/PM_{2.5}$	0.54 g/kW-hr	0.54 g/kW-hr	0.20 g/kW-hr (PM)

(1) Sum of NOx and HC limits; 9.2 g/kW-h and 1.3 g/kW-h
(2) Standards for new 577 hp and 823 hp emergency generators per 40 CFR 89.112, Table 1
(3) Standards for new 310 hp fire pump per 40 CFR Part 60 Subpart IIII, Table 4

The current NSPS Subpart IIII emissions standards for NO_x+NMHC, CO, and PM are the same or more stringent than the limits that apply to the SGS emergency engines. Although control technologies exist that can reduce NO_x, VOC, CO and PM (e.g., water or urea injection for NO_x control, catalyst for CO and VOC), it is not practical to install such controls on existing Tier 1 diesel engines, especially engines that are limited to less than 37.5 hours per year operation for required testing and routine maintenance. Using 37.5 hours per year as a basis, the potential NO_x, VOC, CO or PM_{10} emissions reductions associated with meeting current NSPS Subpart IIII emissions limits would be less than 0.1 ton per year each. Because there are no available control technologies, or other improvements, with a practical application on the existing diesel engines, emissions improvements for the SGS diesel engines will not be evaluated at this time.

In addition to the diesel engines, a propane-fired emergency generator is installed at SGS. S&L's review of emissions data sheets along with discussions with SRP personnel indicate that the propane generator is operating in accordance with permit requirements. Based on limited annual operation and low emissions associated with firing propane, emissions improvements for the SGS propane generator will not be evaluated.

4.5 ABRASIVE BLASTING EQUIPMENT

SGS is equipped with an abrasive blast shed where parts and equipment are cleaned and blasted with abrasive media. The current permit for SGS states that the abrasive blasting operations must comply with applicable requirements of County Rule 312: Abrasive Blasting. County Rule 312 states "no owner or operator shall discharge into the atmosphere from any abrasive blasting any air contaminant for a period or periods aggregating more than three minutes in any one-hour period an opacity greater than 20 percent."

A new dust collector was installed in late 2010 for the SGS abrasive blasting equipment. The new dust collector is designed to achieve a control efficiency of 99.9%. With the installation of the new dust collector, there are no additional controls or other improvements capable of providing further PM_{10} control from this source. Therefore, emissions improvements for the abrasive blasting equipment will not be evaluated at this time.

4.6 FUEL STORAGE TANKS

SGS is equipped with three diesel storage tanks and one gasoline storage tank. The Permit lists the diesel storage tanks as "insignificant activities." Because of the low vapor pressure of diesel fuel, it is commonly accepted that VOC emissions associated with diesel fuel storage and handling are minimal. Therefore, emissions improvements for the diesel storage tanks will not be evaluated.

With regards to the gasoline storage tank, Permit Condition 19.J requires the following design considerations:

- "basic tank integrity" such that "no vapor or liquid escapes are allowed through a dispensing tank's outer surfaces, nor from any of the joints where the tank is connected to the pipe(s), wires, or other systems"
- "each fill-line into a stationary dispensing pipe shall be equipped with a permanent submerged fill-pipe"
- "fill pipe caps" having a "securely attached, intact gasket"
- "overfill protection equipment" that is "vapor tight to the atmosphere"

In addition to the gasoline storage tank design requirements, the Permit restricts annual gasoline throughput to less than 120,000 gallons. VOC emissions are minimized with required gasoline handling procedures identified in Permit Condition 19.J.6.a. Per discussion with SRP personnel, the gasoline storage tank design and fuel handling procedures are in compliance with the requirements of Permit Condition 19.J.

Based on a review of environmental regulations for other states and air quality districts, the MCAQD requirements generally coincide with regard to gasoline storage tank design and fuel handling requirements for new gasoline storage tanks of similar size and annual throughput. Modifications to reduce emissions any further, such as employing vapor recovery systems used at high throughput commercial gas stations, could be installed. However, based on S&L's engineering judgment, such modifications would be cost prohibitive. Therefore, emissions improvements for the gasoline storage tank will not be evaluated at this time.

4.7 FACILITY O&M EVALUATION

As part of the CEC Condition 38 assessment required by the ACC for SGS, S&L evaluated the Operations and Maintenance practices to investigate the possibility of reducing emissions from current operating levels by either: a) changing O&M practices or b) implementing new emissions reduction technologies.

The SGS O&M Program encompasses the following activities:

i. A documented Preventive Maintenance and Inspection program for the emission control equipment,

ii. A Preventive / Predictive Maintenance program to maintain equipment reliability and performance,

iii. A Work Management Process to complete station activities efficiently,

iv. Several Performance Monitoring Systems to provide technical information for plant staff, and

v. Reliable modern control systems that automate system operations.

S&L reviewed O&M procedures, inspection schedules, and O&M manuals for each of the combined cycle units, the cooling towers, and the diesel engines. For the combined cycle units, S&L evaluated the Preventative Maintenance and Inspection program for the dry low-NO_x burners, CO catalyst, SCR system, and the dust collector for abrasive blasting equipment.

S&L prepared the Santan Emissions Operating and Maintenance Practices Assessment Report SL-013397, which has been provided in Attachment 5. The assessment did not find opportunities where a change in O&M practices would help reduce air emissions.

4.8 SUMMARY OF PHASE 1 EMISSIONS ASSESSMENT

The Phase 1 emissions assessment included a review of plant data that reflect current SGS emissions. This information was then processed so it could be utilized for an initial comparison to the emissions rates that are considered to be achievable. In conjunction, a review of equipment operating practices was performed to determine if O&M improvements could be implemented to reduce emissions. The results of this initial assessment were discussed in Sections 4.1 through 4.6, and are summarized in Table 4-10.

Table 4-10. Summary of Phase 1 Emissions Assessment

Emission Source		**Pollutant**					**Emissions Improvements Further Evaluated?**
		NOx	**CO**	**VOC**	**PM_{10} / $PM_{2.5}$**	**SO_2**	
Units 1-4	**SGS (Actual)**	**< 20 ppm (normal operation)**	**< 4 ppm (normal operation)**	**~1.7 ppm (reported)** **1.4 ppm (guarantee – 80-100% load)**	**0.0066 lb/mmBtu (reported)** **5 lb/hr (guarantee)**	**Fuel S Content < 0.076 $gr/100ft^3$**	**Yes - NO_x/CO** **No – VOC/PM/SO_2 *(Emissions reductions will not be evaluated due to (1) DLN-1 combustors/CO catalyst for VOC, and (2) firing low sulfur fuel and good combustion practices for PM/SO_2)***
	Recent Permit Limits	***2-2.5 ppm (50% to 100% load)***	***0.9-4 ppm (50% to 100% load)***	***0.7-5 ppm (50% to 100% load)***	***0.0033 - 0.014 lb/mmBtu***	***Fuel S Content 0.2-5 gr/ $100ft^3$***	
Units 5-6	**SGS (Actual)**	**< 2 ppm**	**< 1 ppm**	**< 1 ppm**	**<0.005 lb/mmBtu**	**Fuel S Content < 0.076 $gr/100ft^3$**	**No *(Emissions reductions will not be evaluated because Units 5-6 are already equipped with state-of-the-art emissions controls and based on S&L's engineering judgment, any changes would cost well in excess of the typical cost thresholds)***
	Recent Permit Limits	***2-2.5 ppm (50% to 100% load)***	***0.9-4 ppm (50% to 100% load)***	***0.7-5 ppm (50% to 100% load)***	***0.0033 - 0.014 lb/mmBtu***	***Fuel S Content 0.2-5 gr/ $100ft^3$***	
Cooling Towers	**SGS (Actual)**	**NA**	**NA**	**NA**	**Drift < 0.0005%**	**NA**	**No *(Emissions reductions will not be evaluated because SGS cooling tower mist eliminator drift efficiency is less than 0.0005%)***
	Recent Permit Limits	***NA***	***NA***	***NA***	***Drift < 0.0005-0.001%***	***NA***	

Table 4-10. Summary of Phase 1 Emissions Assessment (continued)

Emission Source		Pollutant					Emissions Improvements Further Evaluated?
		NOx	CO	VOC	PM_{10} / $PM_{2.5}$	SO_2	
Emergency Diesel Engines	**Fire Pump (310 hp) and Sump Pump Emergency Generator (823 hp) (Actual)**	**9.2 g/kW-hr**	**11.4 g/kW-hr**	**1.3 g/kW-hr**	**0.54 g/kW-hr**	**Fuel S Content < 0.0015 wt%**	**No** ***(Additional emissions control technology is not practical for limited use engines such as emergency generators, and the emissions reductions generated by such controls would be < 0.1 tpy, so improvements are not further evaluated because, based on S&L's engineering judgment, the cost effectiveness of such controls would be well in excess of typical cost thresholds)***
	Turning Gear Emergency Generator (577 hp) (Actual)	**4.0 g/kW-hr**	**3.5 g/kW-hr**	**1.3 g/kW-hr ($NMHC+NO_x$)**			
	Recent Permit Limits	***NOx + NMHC: 4.0 g/kW-hr (310 hp fire pump, 577 hp generator) NOx + NMHC: 6.4 g/kW-hr (823 hp generator)***	***3.5 g/kW-hr (310 hp fire pump, 577/823 hp generators)***	***NOx + NMHC: 4.0 g/kW-hr (310 hp fire pump, 577 hp generator) NOx + NMHC: 6.4 g/kW-hr (823 hp generator)***	***0.20 g/kW-hr (310 hp fire pump, 577/823 hp generators)***	***Fuel S Content < 0.0015 wt%***	
Abrasive Blasting Equipment	**SGS (Actual)**	**NA**	**NA**	**NA**	**Opacity < 20%**	**NA**	**No** ***(Equipped with dust collector that achieves 99.9% PM control)***
	Recent Permit Limits	***NA***	***NA***	***NA***	***Opacity < 20%***	***NA***	
Gasoline Storage Tank	**SGS (Actual)**	**NA**	**NA**	**NA(1)**	**NA**	**NA**	**No** ***(Emissions reductions will not be evaluated because tank design and fuel handling procedures generally meet requirements for similar tanks, and based on S&L's engineering judgment, making any physical changes would be cost prohibitive compared to typical thresholds)***
	Recent Permit Limits for similarly sized tanks	***NA***	***NA***	***NA(1)***	***NA***	***NA***	

(1) VOC emissions from gasoline storage tanks are controlled by utilizing proper tank design (e.g., submerged fill pipe) and fuel handling procedures to minimize vapor losses, and limiting annual fuel throughput.

5 PHASE 2 EVALUATION: EMISSIONS REDUCTION OPTIONS

Based on the results of the "Phase 1 Evaluation, this Phase 2 Evaluation explores potential NO_x and CO emissions improvements for Units 1-4. This analysis generally follows a "top-down" approach that is used in permitting new major sources of air emissions or modifications to an existing major source. A similar process has been used by state and county agencies in evaluating NO_x emission controls at existing stationary sources as part of a regional ozone attainment strategy. The top-down approach utilized in this evaluation includes the following steps for each emission source and pollutant that is being evaluated:

1. Identify potential control technologies.
2. Eliminate technically infeasible control options.
3. Rank the remaining control technologies by control effectiveness.
4. Evaluate the control technologies, starting with the most effective for:
   - economic impacts,
   - environmental impacts, and
   - energy impacts.
5. Summary of potential emissions improvements.

A more detailed description of each step in the top-down control technology analysis is provided below.

5.1 TOP-DOWN CONTROL TECHNOLOGY EVALUATION PROCESS

Step 1 - Identify All Control Options

The first step in this top-down control technology analysis is to identify, for the emission unit in question, available control options. Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. For this evaluation, the emission units that are being evaluated are the existing SGS Units 1-4 combined cycle units.

In an effort to identify potentially applicable emission control technologies for Units 1-4, S&L conducted a comprehensive review of available sources of technical information, including but not necessarily limited to:

- EPA's Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State new source review permits; and
- Technical journals, reports, newsletters and air pollution control seminars.

Step 2 - Eliminate Technically Infeasible Control Options

The second step in this top-down control technology analysis is to review the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility. Options that are technically infeasible for the intended application are eliminated from further review.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All technically feasible options are ranked in order of overall control effectiveness. Control effectiveness is generally expressed as the rate that a pollutant is emitted after the control system. The most effective control option is the system that achieves the lowest emissions level.

Step 4 - Evaluate Most Effective Controls

After identifying the technically feasible control options, each option, beginning with the most effective, is evaluated for associated economic, energy and environmental impacts. Both beneficial and adverse impacts may be assessed and, where possible, quantified. In the event that the most effective control alternative is shown to be inappropriate due to economic, environmental or energy impacts, the basis for this finding is documented and the next most stringent alternative evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific economic, environmental or energy impacts.

Economic Analysis

The economic analysis performed as part of this top-down control technology analysis examines the cost-effectiveness of each control technology, on a dollar per ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from base case emissions to calculate tons of pollutant controlled per year. The base case generally represents uncontrolled emissions or the inherent emission rate from the proposed source. Annual costs are calculated by adding annual operation and maintenance costs to the annualized capital cost of an option. The cost effectiveness ($/ton) of an option is simply the annual cost ($/yr) divided by the annual amount of pollutants controlled (ton/yr).

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control may also be calculated to evaluate the cost effectiveness of the more stringent control.

Environmental Impact Analysis

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal. The environmental impact analysis should be made on a consideration of site-specific circumstances.

Energy Impact Analysis

The energy requirements of a control technology can be examined to determine whether the use of that technology results in any significant or unusual energy penalties or benefits. Two forms of energy impacts associated with a control option can normally be quantified. First, increases in energy consumption resulting from increased heat rate may be shown as total Btu's or fuel consumed per year or as Btu's per ton of pollutant controlled. Second, the installation of a particular control option may reduce the output and/or reliability of equipment. This reduction would result in loss of revenue from power sales and/or increased fuel consumption due to use of less efficient electrical and steam generation methods.

Step 5 – Summary of Potential Emissions Improvements

Based on the results of Steps 1 through 4, Step 5 provides a summary of potential emissions improvements for the generating units that are being evaluated.

The methodology described above will be applied to the SGS Units 1-4 combined cycle units. Based on the results of the Phase 1 Evaluation included in Section 4, potential emissions improvements were evaluated for the following pollutants:

- Nitrogen Oxides (NO_x)
- Carbon Monoxide (CO)

5.2 NO_X CONTROL OPTIONS FOR UNITS 1-4

5.2.1 Step 1: Identify Feasible NO_x Control Options

Potentially available control options were identified based on a comprehensive review of available information. NO_X control technologies with potential application to Units 1-4 are listed in Table 5-1. Similar technologies were investigated in the 2011 Condition 38 Assessment, and only the Advanced Multi-Function Catalyst (AMFC) has been added to the list of technologies.

Table 5-1. List of Potential NO_x Control Options (Units 1-4)

Control Technology
Combustion Controls
Baseline Combustion Controls (DLN-1 Combustors)
Combustor Upgrades
Post-Combustion Controls
Selective Catalytic Reduction (SCR)
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
Urea Injection Systems (Selective Non-Catalytic Reduction and NOxOut™)
Ammonia Injection Systems (Thermal DeNOx™)
Catalytic Combustion (Xonon™)
Advanced Multi-Function Catalyst (AMFC)

5.2.2 Step 2: Technical Feasibility of NOx Control Options

NO_x control technologies can be divided into two general categories: combustion controls and post-combustion controls. Combustion controls reduce the amount of NO_x that is generated in the combustors. Post-combustion controls remove NO_x from the CT exhaust gas.

5.2.2.1 Combustion Controls

NO_x formation in a natural gas-fired CT occurs by three fundamentally different mechanisms; thermal NO_x, prompt NO_x, and fuel NO_x. Essentially all NO_x formed from natural gas combustion is thermal NO_x. Thermal NO_x is created by the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. The amount of thermal NO_x formed is a function of the combustion chamber design and the CT operating parameters, including flame temperature, residence time at flame temperature, combustion pressure, and fuel/air ratios at the primary combustion zone. The maximum thermal NO_x formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The rate of thermal NO_x formation is also an exponential function of the flame temperature. Uncontrolled NO_x emissions from a natural gas-fired combustion turbine will be in the range of 0.32 lb/mmBtu (or approximately 90 ppmvd @ 15% O_2).[4]

Prompt NO_x is formed from reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x forms within the flame and is usually negligible when compared to thermal NO_x.

Fuel NO_x is formed by the gas-phase oxidation of fuel-bound nitrogen compounds with oxygen. Its formation is dependent on fuel nitrogen content and the combustion oxygen levels. Natural gas contains negligible chemically-bound fuel nitrogen; thus, the formation of fuel NO_x is also negligible when compared to thermal NO_x.

Excess air in lean combustion cools the flame and reduces the formation of thermal NO_x. Dry low NO_x (DLN) combustion systems reduce the amount of thermal NO_x formed by lowering the overall flame temperature within the CT combustor. The lower flame temperature is accomplished by premixing the fuel and air at controlled stoichiometric ratios prior to combustion.

Prior to the development of premix-based DLN combustors, fuel and air were injected separately into the CT's combustor section. Oxygen in the combustion air, needed to support the combustion process, would diffuse into the flame front located at the combustor's fuel burner, and combustion occurred in a diffusion flame. The result of this approach was a range of fuel-to-air ratios over which combustion occurred and a corresponding range of flame temperatures.

For DLN combustor designs, air/fuel mixing is accomplished prior to the burner where the actual combustion occurs. This design provides better control of the air-to-fuel stoichiometric ratio, lower flame temperature, reduced excess oxygen, and minimizes the potential for localized high-temperature fuel-rich pockets.

Baseline Combustion Controls (DLN-1 Combustors)

The original combustors for Units 1 through 4 were replaced with GE's DLN-1 combustors in 2001. The DLN-1 combustors are two-stage premix combustors designed to fire both natural gas and fuel oil. Although the DLN-1 combustors are typically designed to achieve NO_x levels of 9 ppmvd @ 15% O_2 and CO levels of 25 ppmvd @ 15% O_2 while firing natural gas, the DLN-1 combustors for Units 1-4 were required to achieve CO levels of 10 ppmvd @ 15% O_2. Therefore,

[4] See, AP-42 Table 3.1-1; NO_x Emission Factor for Uncontrolled Natural Gas-Fired Turbines.

the Units 1-4 DLN-1 combustors were designed to meet NO_x levels of 20 ppmvd @ 15% O_2 while firing natural gas so that the reduced CO levels could be achieved.

<u>Combustor Upgrades</u>

Since 2001, DLN combustor technology has matured and DLN systems installed on new combustion turbines have demonstrated the ability to achieve NO_x levels below 10 ppmvd @ 15% O_2. For example, GE's DLN-1+ combustors include redesigned secondary fuel nozzles, optimized air-fuel mixing, and updated control systems that enable the combustors to achieve NO_x levels as low as 4 ppmvd @ 15% O_2, with CO levels in the range of 25 ppmvd @ 15% O_2. However, to achieve CO levels equal to or less than current levels of 10 ppmvd @ 15% O_2, the design NO_x levels would be in the range of 7 to 9 ppmvd @ 15% O_2.

Combustor upgrades are a technically feasible and commercially available option for reducing NO_x emissions. Based on information from combustor vendors, combustor upgrades on Units 1-4 will be evaluated at a controlled NO_x level of 8 ppmvd @ 15% O_2 while firing natural gas and operating from 50% to 100% load, which represents a NO_x reduction of approximately 60% from the baseline level. A combustor design NO_x level of 8 ppm was selected such that combustor upgrades will result in a slight reduction in CO emissions (see Section 5.3.2).

5.2.2.2 Post-Combustion Controls

A second strategy to minimize NO_x emissions from a natural gas-fired combined cycle unit is to reduce NO_x formed in the CT/HRSG using a post-combustion control system. Potentially available post-combustion NO_x control systems are evaluated below.

<u>Selective Catalytic Reduction</u>

Selective catalytic reduction (SCR) is a post-combustion NO_x control technology. SCR reduces NO_x by injecting ammonia (NH_3) in the presence of a catalyst. Ammonia reacts with NO_x in the presence of active catalyst and excess oxygen to form water vapor and nitrogen, as shown in the following equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The performance of an SCR system is influenced by several factors including flue gas temperature, SCR inlet NO_x level, the catalyst surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable.

SCR catalysts used in combined cycle applications generally consist of vanadium pentoxide as an active ingredient mixed with titanium dioxide as a substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the gas 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.

Flue gas temperature and residence time must be taken into consideration when designing a SCR control system. The temperature range for base metal catalyst is in the range of 400°F and 800°F. On a combined-cycle combustion turbine, this temperature window occurs within the HRSG, downstream of the gas turbine.

Controlled NO_x emission rates achievable with a SCR control system are a function of the catalyst volume, ammonia-to-NO_x (NH_3:NO_x) ratio, reaction temperature, and catalyst activity. For a given catalyst volume, higher NH_3:NO_x ratios can be used to achieve higher NO_x emission reductions, but this control strategy can result in an unacceptable increase in emissions of unreacted NH_3 (ammonia slip).

Catalyst activity is a function of catalyst age and deactivation. SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation (catalyst sintering) if the catalyst is exposed to excessive temperatures (typically > 800°F) over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include compounds containing arsenic, and salts of potassium, sodium, and calcium. On a natural-gas combined cycle unit, where only natural gas is fired, potential catalyst poisons should be minimal, and a catalyst life of approximately 5 years can be expected.

Ammonia slip should be minimized due to the potential for salt formation from the reaction of ammonia with sulfur compounds in the flue gas. The combustion of sulfur-bearing fuels produces SO_2, and to a lesser degree, sulfur trioxide (SO_3). Some conversion of SO_2 to SO_3 also occurs across the SCR catalyst bed. SO_3 in the flue gas can react with ammonia to form ammonium sulfate and/or ammonium bisulfate. Ammonium bisulfate is a sticky compound, which can deposit in the low-temperature region of the HRSG, resulting in increased back-pressure on the CT and reduced heat transfer efficiency in the HRSG. A unit shutdown is generally required to remove ammonium bisulfate deposits from heat transfer surfaces.

The rate of ammonium salt formation increases with increasing levels of SO_3 and NH_3, and decreasing stack gas temperature. Ammonium sulfate and bisulfate are also classified as filterable particulates; thus, the formation of ammonium salts results in an increase in PM_{10} emissions. Because Santan Units 1-4 fire natural gas exclusively, these issues should be minimal; however, to minimize potential operating issues and to minimize ammonia and filterable particulate emissions, ammonia slip should still be maintained below a level of approximately 5 ppmvd.

Based on a review of the Unit 1-4 HRSG drawings, three SCR placement options were considered: (1) CT plenum outlet, (2) stack, and (3) superheater section. This first placement option, CT plenum outlet, would require installation of a high temperature catalyst that could withstand exhaust temperatures in excess of 1000°F. S&L investigated if any advancements have been made to high temperature SCR operation since the last Santan emissions assessment. However, no significant or reliable improvements have been made to high temperature SCR technology; and therefore SCR placement at the CT plenum outlet will not be considered at this time.

The second SCR placement option is at the HRSG stacks for Units 1-4. This option would potentially require expanding the stack ductwork to reduce the exhaust velocity and raising the stack height by approximately 30 feet. Unlike the option to place the SCR in the superheater / evaporator section (see description below), locating the SCR at the stack would reduce costs since piping, tubes, and drums would not have to be raised. However, a primary concern lies with the exhaust temperature of approximately 320°F. Although OEMs typically require a minimum SCR operating temperature of 500°F, it is generally feasible to operate an SCR system at temperatures as low as 350°F. However, at temperatures in the range of 300°F to 350°F, there is potential that ammonium bisulfate will be formed thus resulting in a loss in unit performance. Therefore, based on a typical stack temperature of 320°F, SCR installation at the Units 1-4 HRSG stacks will not be considered at this time.

The third SCR placement option for Units 1-4 is in the superheater / evaporator section to take advantage of an optimal exhaust gas temperature ranging from 500°F to 700°F. The superheater / evaporator sections of the Units 1-4 HRSGs are vertical and confined which means that SCR installation would require expanding the ductwork and raising the piping, tubes, drum and stack approximately 30 feet to accommodate the SCR reactor and ammonia injection grid assembly.

SCR is considered a technically feasible and commercially available NO_X control technology for Santan Units 1- 4 if the SCR reactor and ammonia injection grid is located in the HRSG superheater / evaporator section. Based on a review of emission rates achieved in practice at similar sources and emission limits included in recently issued Prevention of Significant Deterioration (PSD) permits for natural gas-fired combined cycle facilities, S&L concludes that an SCR control system could be designed to achieve a controlled NO_X emission rate of 2.0 ppmvd @ 15% O_2 at loads ranging from 50 to 100%, thus representing a NO_x reduction of approximately 90% from the baseline level.

<u>Oxidation Catalyst w/ Potassium Carbonate Absorption</u>

EMx™ (SCONOx™) is a post-combustion, multi-pollutant control technology, originally developed by Goal Line Environmental Technologies (now EmeraChem LLC). The EMx™ technology uses a coated oxidation catalyst to remove NO_x, CO, and VOC emissions in the turbine exhaust gas by oxidizing CO to carbon dioxide (CO_2), nitric oxide (NO) to nitrogen dioxide (NO_2), and hydrocarbons to CO_2 and water. The CO_2 is then emitted to the atmosphere, and the NO_2 is absorbed onto the potassium carbonate coating on the EMx™ catalyst to form potassium nitrate/nitrite. These reactions are referred to as the "oxidation/absorption cycle."

Because the potassium carbonate coating is consumed as part of the absorption step, it must be regenerated periodically. This is accomplished by passing a regeneration gas containing hydrogen and carbon dioxide across the surface of the catalyst in the absence of oxygen. The hydrogen in this gas reacts with nitrites and nitrates to form water vapor and elemental nitrogen. The carbon dioxide in the gas reacts with the liberated potassium oxide to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. These reactions are called the "regeneration cycle." Water vapor and elemental nitrogen are exhausted, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to repeat.

Because the regeneration cycle must take place in an oxygen-free environment, the catalyst undergoing regeneration must be isolated from the CT-HRSG exhaust gas. This is accomplished by dividing the catalyst bed into discreet sections, and placing dampers upstream and downstream of each section. During regeneration, some of the dampers close, isolating a section of the catalyst bed. While this is going on, exhaust gas continues to flow through the remaining open sections of the catalyst bed. After the isolated section of catalyst has been regenerated, another set of dampers closes so that the next section of catalyst can be isolated for regeneration. This cycle is repeated for each catalyst section approximately once every 5 minutes.

The EMx™ catalyst is very sensitive to fouling, because the potassium coating is irreversibly deactivated by sulfur in the exhaust gas. For large-scale applications, however, EmeraChem recommends using a sulfur oxidation/absorption catalyst, called ESx^{TM} (formerly SCOSOx), to remove sulfur from the exhaust gas. The ESx^{TM} catalyst would be located upstream of the EMx^{TM} catalyst, and would be regenerated at the same time as the EMx^{TM} catalyst. Regeneration of the ESx$_{TM}$ catalyst would result in an off-gas consisting of hydrogen sulfide (H_2S) and/or SO_2. The H_2S/SO_2 off-gas would be discharged to the HRSG stack and emitted into the atmosphere.

The EMx^{TM} multi-pollutant control system has operated successfully on several smaller natural gas-fired units. Potential advantages of the EMx™ control system include the concurrent control of CO and VOC emissions and the fact that the control system does not use a reactant. However, there are a number of engineering challenges associated with applying this technology to larger plants with full scale operations such as the SGS Units 1-4. Potential issues include the following:

- For large-scale natural gas combined cycle (NGCC) applications, the EMx™ catalyst would have to be placed in the HRSG where the exhaust gas temperatures will be in the range of 500 to 700°F. Performance of the EMx^{TM} catalyst in a high-temperature application has not been demonstrated in practice.
- The dampers and damper bearings, which are moving parts exposed to the hot exhaust gas, could present long-term maintenance and reliability problems. This is particularly true as the damper size and number of dampers increase, as would be necessary in order to use this technology for Units 1-4.
- Regeneration of the EMx^{TM} catalyst would require hydrogen gas to be continuously generated (from natural gas) and introduced into the high-temperature zone of the HRSG. Because hydrogen gas is explosive, any leaks in the dampers used to isolate the catalyst for regeneration could create a serious hazard.
- In addition to periodic regeneration, the EMx^{TM} catalyst would have to be cleaned at least once per year by removing the catalyst beds from the HRSG and dipping them in a potassium carbonate solution.
- The EMx^{TM} and ESx™ processes have the potential to create additional air pollutants, such as H_2S. Emissions of these additional pollutants have not been completely quantified.

To date, the EMx™ (SCONOx) multi-pollutant control system has not been installed and operated on a large gas-fired combined cycle application. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system for Units 1-4. Therefore, at this time the EMx™ control system is not considered an available NOx control system, and will not be further evaluated.

<u>Urea Injection Systems (Selective Non-Catalytic Reduction and NO_xOut^{TM})</u>

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at flue gas temperatures of approximately 1600 - 1900 ºF. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water. The NO_x reduction reactions in an SNCR are driven by the thermal decomposition of ammonia or urea and the subsequent reduction of NO_x. SNCR systems do not employ a catalyst to promote these reactions.

Flue gas temperature at the point of reagent injection can greatly affect NO_x removal efficiencies and the quantity of reactant that will pass through the SNCR unreacted (e.g., slip). At temperatures below the desired operating range, the NO_x reduction reactions diminish, and unreacted reactant emissions increase. Above the desired temperature range, the reactant may be oxidized to NO_x resulting in low NO_x reduction efficiencies.

The NO_xOut^{TM} process is a post-combustion NOx reduction method in which aqueous urea is injected into the flue gas stream. The urea reacts with NOx in the flue gas to produce N_2 and water as shown below:

$(NH_2)_2CO + 2NO + \frac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$

The use of urea to control NO_x emissions was developed under the sponsorship of the Electric Power Research Institute (EPRI). The urea-NO_x reaction takes place over a narrow temperature range, below which ammonia is formed and above which NO_x emission levels may actually increase. Fuel Tech's NOxOut™ process is a urea-based SNCR process that uses mechanical modifications and chemical injection hardware to widen the effective temperature range of the reaction to between 1,600 and 1,950°F.

Based on information available from the vendor, the NO_XOut™ process has been demonstrated on a 90 MW GE Frame 7EA gas turbine at a combined cycle cogeneration facility, and was able to achieve a controlled NO_X emission rate of 5 ppm. Potential advantages of the system include lower slip levels (compared to other SNCR designs), no catalyst, and lower capital and operating costs (compared to SCR). Potential disadvantages of the system include ammonia emissions due to excess urea injection, ammonia reacting with SO_3 to form ammonium salts, and potential increase in NO_X emissions if exhaust gas temperatures are too high. To date, commercial application of this system on large natural gas-fired combined cycle units has been limited.

Based on a review of available literature, and engineering judgment, the NO_xOut^{TM} process is not considered a technically feasible NO_x control option for the Units 1-4. NO_x reduction reactions require flue gas temperatures in the range of 1,600 to 1,950°F; however, exhaust gas temperatures from Units 1-4 will be in the range of 1,100°F. Increasing the exhaust gas temperature would significantly reduce the efficiency of the combustion turbine or require additional fuel consumption and installation of a flue gas heater. Neither option is considered practical for a gas-fired combined cycle unit. Therefore, at this time, NO_XOut™ is not considered a technically feasible NO_x control option for Units 1-4, and will not be considered further.

Ammonia Injection Systems (Thermal DeNO$_x$™)

Exxon Research and Engineering Company's Thermal DeNO$_x$™ process utilizes an ammonia/NO_x SNCR reaction to reduce NO_x to nitrogen and water as shown in the following equation:

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$

Hamon Research Cottrell is licensed by Exxon-Mobil for the application of the ammonia-based Thermal DeNO$_x$™ process. The process consists of a high-temperature selective non-catalytic reduction of NO_x using ammonia as the reducing agent. This process does not use a catalyst to aid the reaction; rather temperature control is used to direct the reactions. Optimum reaction temperatures for NO_x reduction are between 1,600°F and 1,800°F. Below the optimum temperature range, ammonia does not fully react and can be released in the flue gas. Above the optimum temperature, the following competing reaction will begin to take place, which can result in increased NO_x emissions:

$4H_3 + 5O_2 \rightarrow 4O + 6H_2O$

To date, commercial applications of the Thermal $DeNO_x$™ process have been limited to furnaces, heavy industrial boilers, and incinerators that consistently produce exhaust gas temperatures in the range of 1,800°F. Because exhaust gas volumes increase significantly with increased temperatures, application of the Thermal $DeNO_x$™ process would require that flue gas handling systems be designed to handle larger high temperature flows. Similar to the NO_xOut™ process, high capital and O&M costs are expected due to material requirements, additional equipment, and fuel consumption. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system on Units 1-4. Therefore, at this time the Thermal $DeNO_x$™ control system is not considered an available NO_x control system, and will not be further evaluated.

Catalytic Combustion (Xonon™)

Catalytic combustion uses a catalyst within the combustor to oxidize a lean air-to-fuel mixture rather than burning with a flame. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_x. One technical challenge associated with catalytic combustion has been achieving catalyst life long enough to make the combustor commercially viable.

The Xonon™ ("no NO_x" spelled backwards) combustion system was originally developed by Catalytica Combustion Systems (now Catalytica Energy Systems). The Xonon™ control system works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is lower temperature partial combustion followed by flameless catalytic combustion to reduce NO_x formation.

To date, the system has successfully completed pilot- and full-scale testing, and has been demonstrated on a 1.5 MW Kawasaki gas turbine. However, the Xonon™ combustion system has not been demonstrated for extended periods of time on a large natural gas-fired combustion turbine. Applications of this technology have been in the 1 to 15 MW range. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system on Units 1-4. Therefore, at this time, catalytic combustion systems (including Xonon™) are not considered available NO_x control systems, and will not be further evaluated.

Advanced Multi-Function Catalyst (AMFC)

In addition to the technologies evaluated in the 2011 Condition 38 Assessment, S&L identified one new technology for NO_X control. AMFC is a post-combustion multi-pollutant technology originally developed and patented by Siemens Energy Inc. AMFC is similar to traditional CO and SCR catalyst already used in the industry and requires ammonia injection for the reduction of NO_X emissions. AMFC reduces NO_X, CO, and VOCs in one layer rather than using two separate catalysts for CO oxidation and SCR. The technology has been optimized for use on gas-fired combined cycle plants.

NO_X reduction efficiency has shown to range between 85 to 95% depending on the exhaust gas temperature. The performance of AMFC is similar to the performance of traditional SCR catalyst.

The benefits of the AMFC may include (1) lower pressure drop across a single catalyst instead of two, (2) low CO stack emissions at low load operation, (3) reduced footprint of a new HRSG with only one catalyst layer, and (4) reduction in SO_2 to SO_3 oxidation compared to a traditional two catalyst configuration.

There are commercial installations of AMFC, including the first installation in December 2014 on a LM6000 combined cycle unit. However, there is limited commercial operating experience with AMFC, and it is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system on SGS Units 1-4.

For SGS Units 1-4, the preferred location of the AMFC, where the existing CO catalyst is located, would not be feasible for the NO_X catalyst. As previously discussed in the description of SCR technology, the SCR reactor and ammonia injection grid must be located in the HRSG superheater / evaporator section for optimal exhaust gas temperature ranging from 500°F to 700°F. Therefore, AMFC would still require the installation of SCR at the superheater / evaporation section. Since the cost of the AMFC would be similar to the cost of SCR only, this technology will not be further evaluated.

Table 5-2. Technical Feasibility of NO_x Control Technologies (Units 1-4)

Control Technology	Approximate Controlled NO_x Emission Rate (ppmvd@15%O_2)	In Service on Existing Gas-Fired Combined Cycle Units?	Technically Feasible on the SGS Units 1-4?
Baseline Combustion Controls (DLN-1 Combustors)	**20**	**Yes**	**Yes – currently installed**
Combustor Upgrades	**8**	**Yes**	**Yes**
SCR	**2**	**Yes**	**Yes**
SCR + Combustor Upgrades (1)	**2**	**Yes**	**Yes**
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)	**NA**	**limited application**	**This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for Units 1-4**
Urea Injection Systems (Selective Non-Catalytic Reduction and NOxOut™)	**NA**	**limited application**	**This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for Units 1-4**
Ammonia Injection Systems (Thermal DeNOx™)	**NA**	**limited application**	**This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for Units 1-4**
Catalytic Combustion (Xonon™)	**NA**	**limited application**	**This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for Units 1-4**
Advanced Multi-Function Catalyst	**NA**	**limited application**	**This control technology is being demonstrated on gas fired combined cycle units, but there is limited commercial operating experience and would result in similar costs as a conventional SCR system based on existing HRSG configuration.**

(1) For the SCR only and SCR + combustor upgrades options, the lowest achievable NO_X emission rate would be 2 ppm. The SCR + combustor upgrades option would have a lower NO_X emission rate at the SCR inlet compared to the SCR only upgrade.

5.2.3 Step 3: Rank the Technically Feasible NO_x Control Options by Effectiveness

The technically feasible and commercially available NO_x control technologies are listed in Table 5-3 in descending order of control efficiency.

Table 5-3. Ranking of Technically Feasible NO_x Control Technologies (Units 1-4)

Control Technology	Controlled NO_x Emission Rate (ppmvd@15%O_2)	% Reduction (from base case)
SCR + Combustor Upgrades	**2**	**90%**
SCR	**2**	**90%**
Combustor Upgrades	**8**	**60%**
Baseline Combustion Controls (DLN-1 Combustors)	**20**	**NA**

The most effective NO_x control system, in terms of reduced emissions, that is considered to be technically feasible for SGS Units 1-4 includes post-combustion SCR. The effectiveness of the SCR system is dependent on several site-specific system variables including inlet NO_x concentrations, the type and size of the SCR catalyst system, flue gas temperatures, ammonia injection system design, and catalyst deactivation rate. This control option should be capable of achieving the most stringent controlled NO_x emission rate on an on-going long-term basis. The other effective NO_x control system that is considered technically feasible and commercially available is combustor upgrades.

5.2.4 Step 4: Evaluation of Technically Feasible NO_x Controls

An evaluation of the economic, environmental and energy impacts of each technically feasible and commercially available NO_x emissions control option is provided below.

NO_x Control Technologies – Economic Evaluation

Economic impacts associated with the potentially feasible NO_x control systems were evaluated using an approach that is similar to the methodology specified in the EPA's New Source Review Workshop Manual (Draft, 1990). For the economic impact analysis, projected annual emissions (tpy) were used to evaluate average cost effectiveness (i.e., dollar per ton removed). Annual emissions (tpy) were calculated assuming: (1) baseline control option emissions are equal to the actual, maximum reported level from years 2013 and 2015; (2) post-control emissions are equal to the baseline control option emissions times the assumed percent reduction associated with each control option.[5]

Cost estimates were compiled from a number of data sources. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Control Cost Manual.[6] Major equipment costs were developed based on information available from equipment vendors and equipment costs recently developed for similar projects. Capital costs include the equipment, material, labor, and all other direct costs needed to install the control technologies. Fixed and variable O&M costs were developed for each control system.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (if applicable), byproduct management, and power requirements. The annual O&M Costs include both of these fixed and variable O&M components. O&M costs account for actual unit capacity factors provided by SRP.

Maximum annual NO_x emission rates associated with each NO_x control technology are summarized in Table 5-4. Table 5-5 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-6 shows the average annual and incremental cost effectiveness for each control system. Detailed cost estimates are provided in Attachment 6.

[5] The baseline emission rates are currently based on actual reported emissions between 2013 and 2015. The emissions estimates that would be required to be used in a permitting action may be different depending on the timeline associated with the project.

[6] U.S. Environmental Protection Agency, *EPA Air Pollution Control Cost Manual*, 6th Ed., Publication
Number EPA 452/B-02-001, January 2002.

Table 5-4. Annual NO_x Emissions (Units 1-4)

Control Technology	Annual Emissions Rate(1) (tpy)	Annual Reduction in Emissions (2) (tpy from base case)
SCR + Combustor Upgrades (3)	16.2	145.4
SCR	16.2	145.4
Combustor Upgrades	64.6	97.0
Baseline Combustion Controls (DLN-1 Combustors)	161.6	NA

(1) Baseline combustion control annual emissions based on maximum, actual emission rates for years between 2013 and 2015.
(2) Annual emissions reductions for SCR catalyst upgrade and combustor upgrade options are based on control efficiencies identified in Table 5-3.
(3) The total NO_X emissions reduction is equivalent for the SCR and SCR + combustor upgrades options. For both options, the lowest achievable NO_X emission rate would be 2 ppm. The SCR + combustor upgrades options would have a lower NO_X emission rate at the SCR inlet compared to the SCR only upgrade.

Table 5-5. NO_x Emissions Control System Cost Summary (Units 1-4)

Control Technology	Total Capital Investment ($)	Annual Capital Recovery Cost(1) ($/year)	Annual Operating Cost ($/year)	Total Annual Costs ($/year)
SCR + Combustor Upgrades	$80,824,000	$8,048,000	$2,228,000	$10,276,000
SCR	$57,448,000	$5,720,000	$1,995,000	$7,715,000
Combustor Upgrades	$23,376,000	$2,328,000	$287,000	$2,615,000
Baseline Combustion Controls (DLN-1 Combustors)	NA	NA	NA	NA

(1) Annual capital recovery cost based on 20 years for life of equipment.

Table 5-6. NO_x Emissions Control System Cost Effectiveness (Units 1-4)

Control Technology	Total Annual Costs ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness(1) ($/ton)
SCR + Combustor Upgrades	$10,276,000	145.4	$70,651	$158,015
SCR	$7,715,000	145.4	$53,043	$105,192
Combustor Upgrades	$2,615,000	97.0	$26,968	NA
Baseline Combustion Controls (DLN-1 Combustors)	NA	NA	NA	NA

(1) Incremental cost effectiveness based on comparison with combustion upgrade option.

Table 5-6 indicates that the average cost effectiveness of the NO_x control systems for Units 1-4 range from $26,968 per ton (combustor upgrades) to $70,651 per ton (SCR + combustor upgrades).[7] Equipment costs, energy costs, and annual operating costs (e.g., routine catalyst replacement) all have a significant impact on the cost of the SCR system.

Total capital costs associated with the SCR systems for Units 1-4 (estimated at $57,448,000), as well as O&M costs (including power costs and catalyst replacement costs) are both significant. The total power costs associated with increased backpressure on the turbine resulting from the SCR system installations are estimated to be $30,000 per year. The total annual costs associated with reagent use, catalyst replacement, and catalyst disposal are estimated to be $373,000 per year. Total annual costs associated with the SCR system installation, including capital recovery are estimated to be $7,715,000 per year.

The significant increase in total annual costs coupled with the relatively small decrease in annual emissions (approximately 145 tpy) results in a very high average cost effectiveness for SCR systems. The average cost effectiveness of the SCR systems (estimated to be $53,043 per ton NO_x removed) is higher than the costs associated with the combustor upgrade option. The incremental cost associated with SCR is estimated to be $105,192 per ton. Both capital costs and annual O&M costs are significantly higher with SCR and contribute to the high cost effectiveness numbers.

Total capital costs associated with the combustor upgrade option for Units 1-4 are estimated to be $23,376,000. The combustor upgrades are expected to result in an increased heat rate, thereby increasing the annual fuel costs by approximately $55,000 per year. Annual maintenance was based on replacing combustor parts, which was estimated to be $232,000 for all four units. Total annual costs associated with the combustor upgrades are estimated to be $2,615,000 per year. The increase in total annual costs coupled with the relatively small decrease in annual emissions (approximately 97 tpy) results in a relatively high average cost effectiveness for combustor upgrades. The average cost effectiveness of the combustor upgrades option is estimated to be $26,968 per ton NO_x removed.

The option to install an SCR system along with upgrades to the CT combustors is the least cost effective control option. Installing SCR (without combustor upgrades) will achieve the same emissions reduction at a lesser cost than SCR with combustor upgrades.

NO_x Control Technologies – Environmental Impacts

Combustion modifications designed to decrease NO_x formation (lower temperature and less oxygen availability) also tend to increase the formation and emission of CO and VOC. Therefore, the combustion controls must be designed to reduce the formation of NO_x while maintaining CO and VOC formation at an acceptable level.

Operation of an SCR system has certain collateral environmental consequences. First, in order to maintain a stringent NO_x emission rate some excess ammonia will pass through the SCR. Ammonia slip will increase with lower NO_x emission limits, and will also tend to increase as the catalyst becomes deactivated. Ammonia slip from an SCR designed to control NO_x emissions from a natural gas fired combined cycle unit is expected to be approximately 10 ppm or less;

[7] The S&L assessment from 2011 estimated the average cost effectiveness range for NO_X control to be $22,104 per ton (combustor upgrades) to $74,369 per ton (SCR + combustor upgrades).

however, ammonia emissions are of concern because ammonia is a potential contributor to regional secondary particulate formation and visibility degradation.

Second, undesirable reactions can potentially occur in an SCR system, including the oxidation of NH_3 and SO_2 and the formation of sulfate salts. A fraction of the SO_2 in the flue gas (approximately 1 - 1.5%) will oxidize to SO_3 in the presence of the SCR catalyst. SO_3 can react with water to form sulfuric acid mist (H_2SO_4) or with the ammonia slip to form ammonium sulfate ($(NH_4)_2SO_4$). Sulfuric acid mist and ammonium sulfate could increase total PM_{10} emissions from the unit.

Another environmental impact associated with SCR is disposal of the spent catalyst. Some of the catalyst used in SCR systems must be replaced every three to five years. These catalysts typically contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. The annual cost associated with proper material handling controls must be initiated when handling and disposing of the spent catalyst.

NO_x Control Technologies – Energy Impacts

Compared with the existing DLN-1 combustors, new DLN-1+ combustors may reduce the efficiency of Units 1-4. Based on vendor information for the DLN-1+ combustor, the power output for Units 1-4 could be reduced by approximately 1.2 MW and the heat rate could increase by 4 Btu/kWh. Assuming a 1.2 MW power output reduction, a power cost of $50/MWh, and a capacity factor of approximately 11%, reduced power costs for combustor modifications will be $55,000 per year. This cost was included in the economic impact evaluation of the combustor modification option, and contributes to the relatively high cost effectiveness value of the system for the control of NO_x emissions.

Post-combustion NO_x control with an SCR system increases the pressure drop of the combustion turbine exhaust thereby reducing the combustion turbine power output. Based on engineering calculations and information provided by catalyst vendors, upgrading the existing oxidation catalyst system to achieve greater than 80% reduction in NO_x emissions will result in an increased pressure drop of approximately 2.0 inch water column (in. w.c.) per unit. Assuming 80 kW/inch power output reduction, a power cost of $50/MWh, and a capacity factor of approximately 11%, total reduced power costs for the SCR control systems will be $30,000 per year. This cost was included in the economic impact evaluation of the SCR systems option, and contributes to the relatively high cost effectiveness value of the system for the control of NO_x emissions.

A summary of the Step 4 economic and environmental impact analysis is provided in Table 5-7.

Table 5-7. Summary of NO_x Controls Evaluation (Units 1-4)

Control Technology	Emissions (tpy)	Emissions Reduction (tpy)	Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness(1) ($/ton)	Environmental Impact
SCR + Combustor Upgrades	**16.2**	**145.4**	**$10,276,000**	**$70,651**	**$158,015**	**Ammonia emissions, increased PM/CO/VOC emissions, and catalyst disposal**
SCR	**16.2**	**145.4**	**$7,715,000**	**$53,043**	**$105,192**	**Ammonia emissions, increased PM emissions, and catalyst disposal.**
Combustor Upgrades	**64.6**	**97.0**	**$2,615,000**	**$26,968**	**NA**	**Potential to increase CO/VOC emissions.**
Baseline Combustion Controls (DLN-1 Combustors)	**161.6**	**NA**	**NA**	**NA**	**NA**	**NA**

(1) Incremental cost effectiveness is based on comparison with combustion upgrade option.

5.2.5 Step 5: Summary of Potential NO_x Improvements for Units 1-4

The NO_x control technology evaluation for Units 1-4 has shown that the combustor upgrade and SCR control options are technically feasible and effective control systems in terms of reduced emissions. An economic evaluation performed for each option indicates that, based on the use of actual baseline emissions and capacity factors, expected emissions reductions, and estimated control costs, the average annual cost effectiveness of the NO_x control systems for Units 1-4 range from $26,968 per ton (combustor upgrades) to $70,651 per ton (SCR + combustor upgrades) NO_x removed.

EPA has not defined a cost threshold at which NO_x control technologies for existing power plants are considered “cost effective.” Cost effectiveness thresholds are typically set at the discretion of regulating agencies on a project-specific basis. However, based on a review of publicly available documents, it is common for agencies to consider the “cost prohibitive” threshold for NO_x control options to range between $5,000 and $10,000 per ton NO_x removed for the retrofit of control technology on gas-fired electric generating units (see Attachment 10 for a table of reference documents). Therefore, based on the range of costs identified for SGS Units 1-4 NO_x control options, NO_x emissions improvements for SGS Units 1-4 would be considered cost prohibitive.

Because the cost effectiveness values are dependent upon the assumed utilization of each unit, figures showing NO_x control cost sensitivities versus capacity factors have been prepared and can be found in Attachment 7.

5.3 CO CONTROL OPTIONS FOR UNITS 1-4

Emissions of CO result from incomplete fuel combustion. CO is formed from the partial oxidation of fuel carbon. Factors that influence CO formation include improper fuel-to air ratios, inadequate fuel mixing, inadequate combustion temperatures, and reduced excess O_2. Combustion turbine operation at lower loads (below approximately 50%) can also affect combustion controls and the formation of CO.

In natural gas-fired combustion turbines, combustion controls designed to minimize NO_X formation, including sub-stoichiometric combustion and reduced peak combustion temperatures, can increase the formation of CO. NO_X control methods such as lean premix combustion, low flame temperature, and water/steam injection can increase CO. Combustors can be designed to minimize the formation of CO while reducing the peak combustion temperature and NO_X emissions.

5.3.1 Step 1: Identify Feasible CO Control Options

Potentially available control options were identified based on a comprehensive review of available information. CO control technologies with potential application to the SGS Units 1-4 are listed in Table 5-8. Similar technologies were investigated in the 2011 Condition 38 Assessment, and only the AMFC has been added to the list of technologies.

Table 5-8. List of Potential CO Control Options (Units 1-4)

Control Technology
Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System
Combustor Upgrades and Existing CO Catalyst System
CO Catalyst System Upgrades
CO Catalyst System Upgrades and Combustor Upgrades
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
Catalytic Combustion (Xonon™)
Advanced Multi-Function Catalyst (AMFC)

5.3.2 Step 2: Technical Feasibility of CO Control Options

The potential CO control options identified in Table 5-8 are described below. In addition to providing a description of each potential control technology, technically feasible and commercially available control options are identified.

5.3.2.1 Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System

Units 1-4 currently utilize combustion controls and an oxidation catalyst system to minimize CO emissions. A general description of current and potential CO emissions controls for SGS Units 1-4 is provided below.

Baseline Combustion Controls (DLN Combustors)

As discussed in Section 5.2.2.1, combustion controls designed to minimize NO_X formation, including lower peak combustion temperatures and less excess oxygen, tend to increase the formation of CO emissions. Burner vendors attempt to address these issues by improving fuel air mixing and ensuring adequate residence times within the combustion zone. Improved mixing will minimize the potential for fuel-rich areas and the resulting formation of CO. Increased residence time within the combustion zone provides the oxygen needed for more complete oxidation.

A properly designed and operated combustion turbine effectively functions as a thermal oxidizer. CO formation is minimized when combustion turbine temperature and excess oxygen availability are adequate for complete combustion. Minimizing CO emissions is also in the economical best interest of the combustion turbine operator because CO represents unutilized energy exiting the process. Proper combustor design and operation can minimize NO_x emissions, while maintaining CO at acceptable levels.

The original combustors for Units 1 through 4 were replaced with GE's Dry Low NO_x (DLN-1) combustors in 2001. The DLN-1 combustors are two-stage premix combustors designed to fire both natural gas and fuel oil. The DLN-1 combustors for Units 1-4 were required to achieve CO levels of 10 ppmvd @ 15% O_2 and NO_x levels of 20 ppmvd @ 15% O_2 while firing natural gas.

Baseline Post-Combustion Controls (Oxidation Catalyst)

Catalytic oxidation systems are designed to oxidize CO to CO_2. Catalytic oxidation is a post-combustion technology which reduces CO emissions without the addition of chemical reagents. The oxidation catalyst, typically consisting of a noble metal, promotes the oxidation of CO at temperatures approximately 50% below the temperature required for oxidation without the catalyst. The operating temperature range for commercially available CO oxidation catalysts is between 650 and 1,150°F. On a natural gas-fired combined cycle unit this temperature window occurs within the HRSG.

Oxidation catalyst efficiency varies with inlet CO concentration, inlet gas temperature, and flue gas residence time. In general, removal efficiency will increase with increased flue gas temperatures and increased catalyst bed depth. Bed depth will be limited by pressure drop across the catalyst.

Oxidation catalyst systems were installed on Units 1-4 in 2003. These systems were designed to achieve 60% CO reduction, or a controlled CO level of 4 ppmvd @ 15% O_2. Approximately 70

ft^3 of catalyst is currently installed in the CT plenum outlet where exhaust temperatures are approximately 1000°F. As indicated in Section 4.1.2, Units 1-4 are generally achieving less than 4 ppm CO at full and mid loads.

5.3.2.2 Combustion Controls Upgrades and Existing CO Catalyst System

Since 2001, DLN combustor technology has matured and DLN systems installed on new combustion turbines have demonstrated the ability to achieving both NO_x and CO levels below 10 ppmvd @ 15% O_2. Combustor upgrades are a technically feasible and commercially available option for reducing CO emissions. Based on information from combustor vendors, combustor upgrades can be implemented to minimize both NO_x and CO emissions. For this evaluation, Units 1-4 will be based on a controlled CO level of 9 ppmvd @ 15% O_2 while firing natural gas and operating from 50% to 100% load. A CO level of 9 ppmvd @ 15% O_2 assumes that the combustors will be designed to achieve a NO_x level of 8 ppmvd @ 15% O_2.

Units 1-4 currently include CO catalyst systems that are designed to achieve 60% CO reduction. With an uncontrolled CO level of 9 ppmvd @ 15% O_2, the CO catalyst would therefore be capable of reducing CO emissions to 3.6 ppmvd @ 15% O_2, which represents a CO reduction of approximately 10% from the baseline level of 4 ppm.

5.3.2.3 CO Catalyst System Upgrades

As described above, the oxidation catalyst systems that are currently installed on Units 1-4 are designed to achieve 60% CO reduction. Approximately 70 ft^3 of catalyst is currently installed in the CT plenum outlet where exhaust temperatures are approximately 1000°F. Based on review of current HRSG and oxidation catalyst system design information, catalyst system modifications can be made thereby resulting in reduced CO emissions.

Catalytic oxidation systems for natural gas-fired combined cycle units have been designed, and have demonstrated the ability, to achieve controlled CO emissions of 2.0 ppmvd @ 15% O_2. CO catalyst upgrades on Units 1-4 would consist of: (1) removing the existing catalyst, internal frame and expansion seals, (2) installing new ceramic based catalyst modules (catalyst volume would be increased), and (3) modifying or replacing the duct spool piece.

Oxidation catalyst system upgrades are considered technically feasible and commercially available control options for Santan Units 1- 4. Based on a review of emission rates achieved in practice at similar sources and emission limits included in recently issued PSD permits for natural gas-fired combined cycle facilities, it is concluded that an upgraded oxidation catalyst system could be designed to achieve a controlled CO emission rate of 2.0 ppmvd @ 15% O_2 at loads ranging from 50 to 100%, thereby representing a CO reduction of approximately 50% from the baseline level.

5.3.2.4 Oxidation Catalyst w/ Potassium Carbonate Absorption

The EMx™ (formerly SCONOx™) control system is described in the NO_x control technology analysis (section 5.2.2.2). EMx™ is a post-combustion, multi-pollutant control technology that uses a coated oxidation catalyst to remove NO_x, CO, and VOC emissions in the turbine exhaust gas by oxidizing CO to CO_2, NO to NO_2, and hydrocarbons to CO_2 and water. The CO_2 is then emitted to the atmosphere, and the NO_2 is absorbed onto the potassium carbonate coating on the EMx™ catalyst to form potassium nitrate/nitrite. Depending on flue gas temperatures, the

EMx™ oxidation catalyst should achieve CO removal efficiencies similar to those achievable with an oxidation catalyst.

As discussed in section 5.2.2.2, there are several currently unresolved technical issues associated with application of the control technology on a large natural gas-fired combined cycle unit. Potential issues include:

- For large-scale combined cycle applications, the EMx™ catalyst would have to be placed in the HRSG where the exhaust gas temperatures will be in the range of 500 to 700 °F. Performance of the EMx™ catalyst in a high-temperature application has not been demonstrated in practice.
- The dampers and damper bearings, which are moving parts exposed to the hot exhaust gas, could present long-term maintenance and reliability problems. This is particularly true as the damper size and number of dampers increase, as would be necessary in order to use this technology for Units 1-4.
- Regeneration of the EMx^{TM} catalyst would require hydrogen gas to be continuously generated (from natural gas) and introduced into the high-temperature zone of the HRSG. Because hydrogen gas is explosive, any leaks in the dampers used to isolate the catalyst for regeneration could create a serious hazard.
- In addition to periodic regeneration, the EMx^{TM} catalyst would have to be cleaned at least once per year by removing the catalyst beds from the HRSG and dipping them in a potassium carbonate solution.
- The EMx^{TM} and ESx™ processes have the potential to create additional air pollutants, such as H_2S. Emissions of these additional pollutants have not been completely quantified.

To date, the EMx™ (SCONOx) multi-pollutant control system has not been installed and operated on a large combined cycle application. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system for Units 1-4. Therefore, at this time the EMx™ control system is not considered an available CO control system, and will not be further evaluated in this analysis.

5.3.2.5 Catalytic Combustion (Xonon^{TM})

Catalytic combustion systems are described in the NO_x control evaluation (section 5.2.2.2). Catalytic combustion uses a catalyst within the combustor to oxidize a lean air-to-fuel mixture rather than burning with a flame. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_x, and potentially lower CO emissions. One technical challenge associated with catalytic combustion has been achieving catalyst life long enough to make the combustor commercially viable. The Xonon™ combustion system works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is lower temperature partial combustion followed by flameless catalytic combustion to reduce CO formation.

As described in section 5.2.2.2, to date, the system has successfully completed pilot- and full-scale testing, and has been demonstrated on a 1.5 MW Kawasaki gas turbine. However, the

Xonon™ combustion system has not been demonstrated for extended periods of time on a large natural gas-fired combustion turbine. Applications of this technology have been in the 1 to 15 MW range. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system for Units 1-4. Therefore, at this time, catalytic combustion systems (including Xonon™) are not considered available CO control systems, and will not be further evaluated in this analysis.

5.3.2.6 Advanced Multi-Function Catalyst (AMFC)

In addition to the technologies evaluated in the 2011 Condition 38 Assessment, S&L identified one new technology for CO control. AMFC is described in the NO_X BACT analysis (Section 5.2.2.2). AMFC is a post-combustion multi-pollutant technology originally developed and patented by Siemens Energy Inc. AMFC is similar to traditional CO and SCR catalyst already used in the industry and requires ammonia injection for the reduction of NO_X emissions. AMFC reduces NO_X, CO, and VOCs in one layer rather than using two separate catalysts for CO oxidation and SCR. The technology has been optimized for use on gas-fired combined cycle plants.

CO reduction efficiency ranges between 70 to 98% depending on the exhaust gas temperature. However, to achieve high CO reduction, the resultant NO_X removal efficiency would be much lower than a traditional combination of CO oxidation catalyst and SCR catalyst.

As previously mentioned in Section 5.2.2.2, the benefits of the AMFC may include (1) lower pressure drop across a single catalyst instead of two, (2) low CO stack emissions at low load operation, (3) reduced footprint of a new HRSG with only one catalyst layer, and (4) reduction in SO_2 to SO_3 oxidation compared to a traditional two catalyst configuration.

There are commercial installations of AMFC, including the first installation in December 2014 on a LM6000 combined cycle unit. However, there is limited commercial operating experience with AMFC, and it is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system at the Santan Units 1-4.

For SGS Units 1-4, the preferred location of the AMFC, where the existing CO catalyst is located, would be feasible for CO reduction, but not NO_X. As previously discussed in the description of SCR technology, the SCR reactor and ammonia injection grid must be located in the HRSG superheater / evaporator section for optimal exhaust gas temperature ranging from 500°F to 700°F. For CO control, the AMFC would only be used if it could be used in the location of the existing CO catalyst. Therefore, AMFC is considered infeasible for CO control on Units 1-4.

Additionally, the AMFC is expected to achieve the same CO reduction as typical CO catalyst. The AMFC option does not provide additional benefit compared to conventional CO catalyst; therefore, this technology will not be evaluated further.

The results of Step 2 of the CO control technology analysis (technical feasibility analysis of potential CO control technologies) are summarized in Table 5-9.

Table 5-9. Technical Feasibility of CO Control Technologies (Units 1-4)

Control Technology	Approximate Controlled CO Emission Rate (ppmvd@15%O_2)	In Service on Existing Gas-Fired Combined Cycle Units?	Technically Feasible on SGS Units 1-4?
Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System	**4**	**Yes**	**Yes - currently installed**
Combustor Upgrades and Existing CO Catalyst System	**3.6**	**Yes**	**Yes**
CO Catalyst System Upgrades	**2**	**Yes**	**Yes**
CO Catalyst System Upgrades and Combustor Upgrades (1)	**2**	**Yes**	**Yes**
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)	**NA**	**limited application**	**This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for Units 1-4**
Catalytic Combustion (Xonon™)	**NA**	**limited application**	**This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for Units 1-4**
Advanced Multi-Function Catalyst	**NA**	**limited application**	**This control technology is being demonstrated on gas fired combined cycle units, but there is limited commercial operating experience and, would not provide any additional NO_X or CO control compared to a conventional CO catalyst system on Units 1-4.**

(1) For the CO catalyst system upgrades only and CO catalyst system upgrades + combustor upgrades options, the lowest achievable CO emission rate would be 2 ppm. The CO catalyst + combustor upgrades option would have a lower CO emission rate at the CO catalyst inlet compared to the CO catalyst system only upgrade.

5.3.3 Step 3: Rank the Technically Feasible CO Control Options by Effectiveness

The technically feasible and commercially available CO control technologies are listed in Table 5-10 in descending order of control efficiency.

Table 5-10. Ranking of Technically Feasible CO Control Technologies (Units 1-4)

Control Technology	Approximate Controlled CO Emission Rate (ppmvd@15%O_2)	% Reduction (from base case)
CO Catalyst System Upgrades and Combustor Upgrades	**2**	**50%**
CO Catalyst System Upgrades	**2**	**50%**
Combustor Upgrades and Existing CO Catalyst System	**3.6**	**10%**
Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System	**4**	**NA**

The most effective CO control system, in terms of reduced emissions, that is considered to be technically feasible for Units 1-4 consists of upgrades to the Units' existing oxidation catalyst system. The effectiveness of the oxidation catalyst system is dependent on several site-specific system variables including inlet CO concentrations, the size of the oxidation catalyst system (e.g., catalyst volume), flue gas temperatures, and catalyst deactivation rate. This combination of controls should be capable of achieving the most stringent controlled CO emission rates on an on-going long-term basis. The other effective CO control system that is considered technically feasible and commercially available is combustor upgrades (install DLN-1+ combustors).

5.3.4 Step 4: Evaluation of Technically Feasible CO Controls

An evaluation of the economic, environmental and energy impacts of each technically feasible and commercially available CO emissions control option is provided below.

CO Control Technologies – Economic Evaluation

Economic impacts associated with the potentially feasible CO control systems were evaluated in accordance with guidelines found in EPA's New Source Review Workshop Manual (Draft, 1990). For the economic impact analysis, projected annual emissions (tpy) were used to evaluate average cost effectiveness (i.e., dollar per ton removed). Annual emissions (tpy) were calculated assuming: (1) baseline control option emissions are equal to the actual, maximum reported level between years 2013 and 2015; (2) post-control emissions are equal to the baseline control option emissions times the assumed percent reduction associated with each control option.[8]

Cost estimates were compiled from a number of data sources. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Control Cost Manual. Major equipment costs were developed based on published information available from equipment vendors and equipment costs recently developed for similar projects. Capital costs include the equipment, material, labor, and all other direct costs needed to install the control technologies. Fixed and variable O&M costs were developed for each control system.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (if applicable), byproduct management, and power requirements. The annual O&M costs include both of these fixed and variable O&M components. O&M costs account for actual unit capacity factors from the year of the baseline emissions.

Maximum annual CO emission rates associated with each CO control technology are summarized in Table 5-11. Table 5-12 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-13 shows the average annual and incremental cost effectiveness for each control system. Detailed cost estimates are provided in Attachment 8.

[8] The baseline emission rates are currently based on actual reported emissions between 2013 and 2015. The emissions estimates included in this evaluation are subject to change if the potential project timeline and respective baseline periods are adjusted.

Table 5-11. Annual CO Emissions (Units 1-4)

Control Technology	Annual Emissions Rate[1] (tpy)	Annual Reduction in Emissions[2] (tpy from base case)
CO Catalyst System Upgrades	**20.07**	**20.07**
CO Catalyst System Upgrades and Combustor Upgrades[3]	**20.07**	**20.07**
Combustor Upgrades and Existing CO Catalyst System	**36.13**	**4.01**
Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System	**40.14**	

(1) Baseline combustion control annual emissions based on maximum, actual emission rates for years between 2013 and 2015.
(2) Annual emissions reductions for CO catalyst upgrade and combustor upgrade options are based on control efficiencies identified in Table 5-10.
(3) The total CO emissions reduction is equivalent for the CO catalyst system upgrades only and CO catalyst system upgrades + combustor upgrades options. For both options, the lowest achievable CO emission rate would be 2 ppm. The CO catalyst system upgrades + combustor upgrades options would have a lower CO emission rate at the CO catalyst inlet compared to the CO catalyst system only upgrade.

Table 5-12. CO Emissions Control System Cost Summary (Units 1-4)

Control Technology	Total Capital Investment ($)	Annual Capital Recovery Cost[1] ($/year)	Annual Operating Cost ($/year)	Total Annual Costs ($/year)
CO Catalyst System Upgrades	**$1,361,000**	**$136,000**	**$198,000**	**$334,000**
CO Catalyst System Upgrades and Combustor Upgrades	**$24,737,000**	**$2,464,000**	**$485,000**	**$2,949,000**
Combustor Upgrades and Existing CO Catalyst System	**$23,376,000**	**$2,328,000**	**$287,000**	**$2,615,000**
Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System	**NA**	**NA**	**NA**	**NA**

(1) Annual capital recovery cost based on 20 years for life of equipment.

Table 5-13. CO Emissions Control System Cost Effectiveness (Units 1-4)

Control Technology	Total Annual Costs ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness ($/ton)
CO Catalyst System Upgrades	**$334,000**	**20.07**	**$16,639**	**NA**
CO Catalyst System Upgrades and Combustor Upgrades	**$2,949,000**	**20.07**	**$146,916**	**$20,799**
Combustor Upgrades and Existing CO Catalyst System	**$2,615,000**	**4.01**	**$651,381**	**NA**
Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System	**NA**	**NA**	**NA**	**NA**

Table 5-13 indicates that the average annual cost effectiveness of the CO control systems for Units 1-4 range from $16,639 per ton (CO catalyst upgrades) to $651,381 per ton (combustor upgrades) CO removed.[9] Equipment costs, energy costs, and annual operating costs (e.g., routine catalyst replacement) all have a significant impact on the cost of the oxidation catalyst control system.

Total capital costs associated with oxidation catalyst system upgrades for Units 1-4 (estimated at $1,361,000), as well as O&M costs (including power costs and catalyst replacement costs) are both significant. The total differential power costs associated with increased backpressure on the turbine resulting from the catalyst system upgrades are estimated to be $30,000 per year. The total differential catalyst replacement costs are estimated to be in the range of $148,000 per year. Total annual costs associated with the oxidation catalyst system upgrades, including capital recovery are estimated to be $334,000 per year. The significant increase in total annual costs coupled with the relatively small decrease in annual emissions (estimated at 20.07 tpy) results in a high average cost effectiveness for the oxidation catalyst control system upgrades.

The other technically feasible and commercially available options (i.e., upgrade the CT combustors, and CO catalyst system upgrades and combustor upgrades) are even less cost effective control options. Oxidation catalyst system upgrades will achieve greater emissions reduction for less cost than the other options.

CO Control Technologies – Environmental Impacts

Combustion modifications designed to decrease CO formation also tend to increase the formation and emission of NO_x. Combustion controls, including dry low NO_x burners, need to be designed to reduce the formation of NO_x while maintaining CO at acceptable levels. Other than the NO_x /CO trade-off, there are no environmental issues associated with using combustion controls to reduce CO emissions from a natural gas-fired combustion turbine.

Operation of an oxidation catalyst control system has certain collateral environmental consequences. The most significant environmental impact is associated with increased condensable PM_{10} emissions. The oxidation catalyst also tends to oxidize flue gas SO_2 to SO_3. Based on information available from catalyst vendors, the SO_2 to SO_3 oxidation rate varies with flue gas temperatures, but will be in the range of 50% for high temperature CO catalyst. SO_3 can react with water to form sulfuric acid mist, or with ammonia slip from the SCR to form ammonium sulfate and/or ammonium bisulfate. Sulfuric acid mist and ammonium sulfate are classified as condensable particulates; thus, oxidation catalyst control could possibly result in increased PM_{10} emissions.

CO Control Technologies – Energy Impacts

Compared with the existing DLN-1 combustors, new DLN-1+ combustors may reduce the efficiency of Units 1-4. Based on vendor information for the DLN-1+ combustor, the Units 1-4 power output could be reduced by approximately 1.2 MW and the heat rate could increase by 4 Btu/kWh. Assuming a 1.2 MW power output reduction, a power cost of $50/MWh, and a

[9] The S&L assessment from 2011 estimated the average cost effectiveness range for CO control to be $63,895 per ton (combustor upgrades) to $464,694 per ton (SCR + combustor upgrades).

capacity factor of approximately 11%, reduced power costs for combustor modifications will be \$55,000 per year. This cost was included in the economic impact evaluation of the combustor modification option, and contributes to the relatively high cost effectiveness value of the system for the control of CO emissions.

Post-combustion CO control with an oxidation catalyst control system increases the pressure drop of the combustion turbine exhaust. The additional pressure drop results in a reduction in the combustion turbine power output. Based on engineering calculations and information provided by catalyst vendors, upgrading the existing oxidation catalyst system to achieve greater than 80% reduction in CO emissions will result in an increased pressure drop of approximately 2.0 in. w.c. per unit. Assuming 80 kW/inch power output reduction, and a power cost of \$50/MWh, and a capacity factor of approximately 11%, total reduced power costs for the oxidation catalyst control system will be \$30,000 per year. This cost was included in the economic impact evaluation of the oxidation catalyst system, and contributes to the relatively high cost effectiveness value of the system for the control of CO emissions.

A summary of the Step 4 economic, environmental and energy impact analysis is provided in Table 5-14.

Table 5-14. Summary of CO Controls Evaluation (Units 1-4)

Control Technology	Emissions (tpy)	Emissions Reduction (tpy)	Total Annual Costs (\$/year)	Average Cost Effectiveness (\$/ton)	Incremental Annual Cost Effectiveness (\$/ton)	Environmental Impact
CO Catalyst System Upgrades	**20.07**	**20.07**	**\$334,000**	**\$16,639**	**NA**	**Increased H_2SO_4 / PM emissions, and catalyst disposal.**
CO Catalyst System Upgrades and Combustor Upgrades	**20.07**	**20.07**	**\$2,949,000**	**\$146,916**	**\$20,799**	**Increased H_2SO_4 / PM emissions, and catalyst disposal.**
Combustor Upgrades and Existing CO Catalyst System (1)	**36.13**	**4.01**	**\$2,615,000**	**\$651,381**	**NA**	**NA**
Baseline Combustion Controls (DLN-1 Combustors) and Existing CO Catalyst System	**40.14**	**NA**	**NA**	**NA**	**NA**	**NA**

5.3.5 Step 5: Summary of Potential CO Improvements for Units 1-4

The CO control technology evaluation for Units 1-4 has shown that combustor upgrade and oxidation catalyst upgrade options are technically feasible and effective control systems in terms of reduced emissions. An economic evaluation performed for each option indicates that, based on the use of actual baseline emissions and capacity factors, expected emissions reductions, and estimated control costs, the average annual cost effectiveness of the CO control systems for Units 1-4 range from $16,639 per ton (CO catalyst upgrades) to $651,381 per ton (combustor upgrades) CO removed.

EPA has not defined a cost threshold at which CO control technologies for existing power plants are considered "cost effective." Cost effectiveness thresholds are typically set at the discretion of regulating agencies on a project-specific basis. However, based on a review of publicly available documents, it is common for agencies to consider CO control options "cost prohibitive" at levels exceeding $4,000 per ton CO removed (see Attachment 10 for a table of reference documents). Therefore, based on the range of costs identified for SGS Units 1-4 CO control options, CO emissions improvements for SGS Units 1-4 would be considered cost prohibitive.

Because the cost effectiveness values are dependent upon the assumed utilization of each unit, figures showing CO control cost sensitivities versus capacity factors have been prepared and can be found in Attachment 9.

5.4 SUMMARY OF PHASE 2 EVALUATION EMISSIONS ASSESSMENT

The NO_x control technology assessment identified three options that are considered technically feasible and commercially available for control of NO_x emissions from Units 1-4: (1) combustor upgrades, (2) SCR system, and (3) SCR system with combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness of available NO_X control technologies ranges from approximately $26,968 per ton (combustor upgrades) and $70,651 per ton (SCR + combustor upgrades).

The CO control technology assessment identified three options that are considered technically feasible and commercially available for control of CO emissions from Units 1-4: (1) combustor upgrades, (2) upgraded oxidation catalyst system, and (3) oxidation catalyst system with combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness of available CO control technologies ranges from approximately $16,639 per ton (CO catalyst upgrades) to $651,381 per ton (combustor upgrades).

6 CONCLUSION

The Phase 1 emissions assessment concluded that there is potential for CO and NO_x emissions reductions from SGS Units 1-4. Therefore, emissions improvements for Units 1-4 were further evaluated in the Phase 2 evaluation. Emissions improvements were not further evaluated for the other SGS emissions sources at this time based on the following findings: (1) Units 5-6 are currently operating at or below levels generally required for similar, recently permitted facilities; (2) cooling towers currently include mist eliminators designed to achieve 0.0005% drift; (3) diesel engine improvements are not practical due to limited annual operation; (4) abrasive blasting equipment is already equipped with dust collection; (5) the gasoline storage tank vapor losses are minimized due to proper tank design, fuel handling procedures, and limited annual gasoline throughput; and (6) the key elements of a comprehensive O&M program are utilized at SGS.

The Phase 2 NO_x control technology assessment performed for Units 1-4 identified three control options that are considered technically feasible and commercially available: (1) combustor upgrades, (2) SCR system, and (3) SCR system with combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness of available NO_X control technologies ranges from approximately \$26,968 per ton (combustor upgrades) to \$70,651 per ton (SCR + combustor upgrades).

The Phase 2 CO control technology assessment identified three options that are considered technically feasible and commercially available for control of CO emissions from Units 1-4: (1) combustor upgrades, (2) upgraded oxidation catalyst system, and (3) upgraded oxidation catalyst system with combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness of available CO control technologies ranges from approximately \$16,639 per ton (CO catalyst upgrades) to \$651,381 per ton (combustor upgrades only).

Based on review of recent NO_x and CO control evaluations for other fossil fuel-fired electric generating units, the estimated NO_x and CO control costs for SGS Units 1-4 are cost prohibitive.

Attachment 1

Arizona Corporation Commission (ACC) Certificate of Environmental Compatibility (CEC)

0000037252

Arizona Corporation Commission
DOCKETED

MAY 01 2001

DOCKETED BY	
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BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

In the matter of the Application of Salt River Project Agricultural Improvement and Power District in conformance with the requirements of Arizona Revised Statutes Sections 40-360-03 and 40-360.06, for a Certificate of Environmental Compatibility authorizing the Expansion of its Santan Generating Station, located at the intersection of Warner Road and Val Vista Drive, in Gilbert, Arizona, by adding 825 megawatts of new capacity in the form of three combined cycle natural gas units, and associated intraplant transmission lines.

Case No. 105

Docket No. L-00000B-00-0105

Decision No. 63611

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Pursuant to notice given as provided by law, the Arizona Power Plant and Transmission Line Siting Committee (the "Committee") held public hearings at the Dobson Ranch Inn, 1644 South Dobson Road, Mesa, Arizona, on September 14, 2000, and various days following, in conformance with the requirements of Arizona Revised Statutes section 40-360 *et seq.*, for the purpose of receiving evidence and deliberating on the Application of Salt River Project Agricultural Improvement and Power District ("Applicant") for a Certificate of Environmental Compatibility in the above-captioned case (the "Application").

The following members or designees of members of the Committee were present for the hearing on the Application:

Paul A. Bullis	Chairman, Designee for Arizona Attorney General Janet Napolitano
Steve Olea	Designee of Chairman of the Arizona Corporation Commission

Richard Tobin	Designee for the Arizona Department of Environmental Quality
Dennis Sundie	Designee for the Director of the Department of Water Resources
Mark McWhirter	Designee for the Director of the Energy Office of the Arizona Department of Commerce
George Campbell	Appointed Member
Jeff Mcguire	Appointed Member
A. Wayne Smith	Appointed Member
Sandie Smith	Appointed Member
Mike Whalen	Appointed Member

The Applicant was represented by Kenneth C. Sundlof, Jr., Jennings, Strouss & Salmon PLC. There were seventeen intervenors: Arizona Utilities Investor Association, by Ray Heyman; Arizona Corporation Commission Staff, by Janice Alward; Arizona Center for Law in the Public Interest, by Timothy Hogan, Mark Kwiat, Elisa Warner, David Lundgreen, Cathy LaTona, Sarretta Parrault, Mark Sequeira, Cathy Lopez, Michael Apergis, Marshal Green, Charlie Henson, Jennifer Duffany, Christopher Labban, Bruce Jones and Dale Borger. There were a number of limited appearances.

The Arizona Corporation Commission has considered the grant by the Power Plant and Line Siting Committee of a Certificate of Environmental Compatibility to SRP and finds that the provisions of A.R.S. §40-360.06 have complied with, and, in addition, that documentary evidence was presented regarding the need for the Santan Expansion Project. Credible testimony was presented concerning the local generation deficiency in Arizona and the need to locate additional generation within the East Valley in order to minimize transmission constraints and ensure reliability of the transmission grid. The evidence included a study that assessed the needs of the East Valley. The analysis found that the East Valley peak load currently exceeds the East Valley import capability and within the next 5 years the East Valley load will exceed the load serving capability.

Additional testimony was presented regarding SRP's projected annual 3.7% load growth in its service territory. By 2008, SRP will need approximately 2700 MW to meet its load. This local generation plant will have power available during peak periods for use by SRP customers.

At the conclusion of the hearing and deliberations, the Committee, having received and considered the Application, the appearance of Applicant and all intervenors, the evidence, testimony and exhibits presented by Applicant and all intervenors, the comments made by persons making limited appearances and the comments of the public, and being advised of the legal requirements of Arizona Revised Statutes Sections 40-360 to 40-360.13, upon motion duly made and seconded, voted to grant Applicant the following Certificate of Environmental Compatibility (Case No. L-00000B-00-0105):

Applicant and its assignees are granted a Certificate of Environmental Compatibility authorizing the construction of an 825 megawatt generating facility consisting of three combined cycle units with a total net output of 825 megawatts together with related infrastructure and appurtenances, in the Town of Gilbert, on Applicant's existing Santan Generating Station site, and related switchyard and transmission connections, as more specifically described in the Application (collectively, the "Project"). Applicant is granted flexibility to construct the units in phases, with different steam turbine configurations, and with different transmission connection configurations, so long as the construction meets the general parameters set forth in the application.

This certificate is granted upon the following conditions:

1. Applicant shall comply with all existing applicable air and water pollution control standards and regulations, and with all existing applicable ordinances, master plans and regulations of the State of Arizona, the Town of Gilbert, the County of Maricopa, the United States, and any other governmental entities having jurisdiction.

2. This authorization to construct the Project will expire five (5) years from the date the Certificate is approved by the Arizona Corporation Commission unless construction of the Project is completed to the point that the project is capable of operating at its rated capacity; provided, however, that Applicant shall have the right to apply to the Arizona Corporation Commission for an extension of this time limitation.

3. Applicant's project has two (2) approved transmission lines emanating from its power plant" transmission switchyard and interconnecting with the existing transmission system. This plant interconnection must satisfy the single contingency criteria (N-1) without reliance on remedial action such as a generator unit tripping or load shedding.

4. Applicant shall use reasonable efforts to remain a member of WSCC, or its successor, and shall file a copy of its WSCC Reliability Criteria Agreement or Reliability Management System (RMS) Generator Agreement with the Commission.

5. Applicant shall use reasonable efforts to remain a member of the Southwest Reserve Sharing Group, or its successor.

6. Applicant shall meet all applicable requirements for groundwater set forth in the Third Management Plan for the Phoenix Active Management Area.

7. With respect to landscaping and screening measures, including the improvements listed in the IGA, Applicant agrees to develop and implement a public process consistent with the process chart (Exhibit 89) presented during the hearings, modifying the dates in the IGA with the Town of Gilbert, if necessary, to correspond with the schedule in Exhibit 89.

   The new Community Working Group (CWG) will consist of 12 members, selected as follows: one member selected by the Town of Gilbert, four members selected by neighborhood homeowner associations, four representatives selected by intervenors, and three members selected by SRP (not part of the aforementioned groups) who were part of the original community working group. Applicant and landscaping consultants shall act as advisors to the CWG. CWG meetings shall be noticed to and be open to the general public. The initial meeting shall take place on an evening or weekend in the Town of Gilbert.

The objective of the CWG shall be to refine the landscaping and mitigation concept plans submitted during these hearings (Exhibit 88). The CWG shall work to achieve appropriate visual mitigation of plant facilities and to facilitate the design and installation of the concept plan components so as to maximize the positive impact on the community and to increase, wherever possible, the values of the homes in the neighboring areas. The refinement of the mitigation plans shall be reasonably consistent with the planning criteria of the Town of Gilbert, the desires of neighboring homeowner associations, and the reasonable needs of Applicant.

Applicant shall retain an independent facilitator, acceptable to the CWG, to conduct the CWG meetings. It shall be the role of the facilitator to assist in initial education and in conducting an orderly and productive process. The facilitator may, if necessary, employ dispute resolution mechanisms.

The CWG shall also assist in establishing reasonable maintenance schedules for landscaping of Applicant's plant site in public-view areas.

Applicant will develop with the Town of Gilbert a continuous fund, to be administered by the Town of Gilbert, to provide for the construction and maintenance of off-site landscaping in the areas depicted in the off-site landscaping concepts as developed by the CWG in an amount sufficient to fund the concepts in Exhibit 88 or concepts developed by the CWG, whichever is greater.

8. The visual mitigation efforts shall be in general compliance with the plans and concepts presented in these proceedings and constitute a commitment level by Applicant. Applicant will not reduce the overall level of mitigation as set forth in its Application and this proceeding, except as may be reasonably changed during the CWG process. The plans agreed to by the CWG shall be approved by the Town of Gilbert.

9. Applicant shall, where reasonable to do so, plant on site trees by the fall of 2001. Because planting of trees must await the improvement of Warner Road and the design and construction of berms, this condition will largely apply to trees on the East side of the site, and some of the trees on the North side. All landscaping will be installed prior to the installation of major plant equipment such as, but not limited to, exhaust stacks, combustion turbines, and heat recovery steam generators, except where delays are reasonably necessary to facilitate construction activities.

10. Applicant shall operate the Project so that during normal operations the Project shall not exceed the most restrictive of applicable (i) HUD residential

noise guidelines, (ii) EPA residential noise guidelines, or (iii) applicable City of Tempe standards. Additionally, construction and operation of the facility shall comply with OSHA worker safety noise standards. Applicant agrees that it will use its best efforts to avoid during nighttime hours construction activities that generate significant noise. Additionally, Applicant agrees to comply with the standards set forth in the Gilbert Construction Noise Ordinance, Ordinance No. 1245, during construction of the project. In no case shall the operational noise level be more than 3 db above background noise as of the noise study prepared for this application. The Applicant shall also, to the extent reasonably practicable, refrain from venting between the hours of 10:00 p.m. and 7:00 a.m.

11. Applicant will work with the Gilbert Unified School District to assist it in converting as many as possible of its school bus fleet to green diesel or other alternative fuel, as may be feasible and determined by Gilbert Unified School District, and will contribute a minimum of $330,000 to this effort.

12. Applicant shall actively work with all interested Valley cities, including at a minimum, Tempe, Mesa, Chandler, Queen Creek and Gilbert, to fund a Major Investment Study through the Regional Public Transit Authority to develop concepts and plans for commuter rail systems to serve the growing population of the East Valley. Applicant will contribute a maximum of $400,000 to this effort.

13. Within six months of approval of this Order by the Arizona Corporation Commission, Applicant shall either relocate the gas metering facilities to the interior of the plant site or construct a solid wall between the gas metering facilities at the plant site and Warner Road. The wall shall be of such strength and size as to deflect vehicular traffic (including a fully loaded concrete truck) that may veer from Warner Road to the gas-metering site.

14. Applicant will use only SRP surface water, CAP water or effluent water for cooling and power plant purposes. The water use for the plant will be consistent with the water plan submitted in this proceeding and acceptable to the Department of Water Resources. Applicant will work with the Town of Gilbert to attempt to use available effluent water, where reasonably feasible.

15. Applicant agrees to comply with all applicable federal, state and local regulations relative to storage and transportation of chemicals used at the plant.

16. Applicant agrees to maintain on file with the Town of Gilbert safety and emergency plans relative to emergency conditions that may arise at the plant site. On at least an annual basis Applicant shall review and update, if necessary, the emergency plans. Copies of these plans will be made available to the public and on Applicant's web site. Additionally Applicant

will cooperate with the Town of Gilbert to develop an emergency notification plan and to provide information to community residents relative to potential emergency situations arising from the plant or related facilities. Applicant agrees to work with the Gilbert police and fire departments to jointly develop on site and off-site evacuation plans, as may be reasonably appropriate. This cooperative work and plan shall be completed prior to operation of the plant expansion.

17. In obtaining air offsets required by EPA and Maricopa County, Applicant will use its best efforts to obtain these offsets as close as practicable to the plant site.

18. In order to reduce the possibility of generation shortages and the attendant price volatility that California is now experiencing, SRP will operate the facilities consistent with its obligation to serve its retail load and to maintain a reliable transmission system within Arizona.

19. Beginning upon operation of the new units, Applicant will establish a citizens' committee, elected by the CWG, to monitor air and noise compliance and water quality reporting. Applicant will establish on-site air and noise monitoring facilities to facilitate the process. Additionally Applicant shall work with Maricopa County and the Arizona Department of Environmental Quality to enhance monitoring in the vicinity of the plant site in a manner acceptable to Maricopa County and the Arizona Department of Environmental Quality. Results of air monitoring will be made reasonably available to the public and to the citizens' committee. Applicant shall provide on and off-site noise monitoring services (at least on a quarterly basis), testing those locations suggested by the citizens' committee. The off-site air monitoring plan shall be funded by the Applicant and be implemented before operation of the plant expansion.

20. Applicant will explore, and deploy where reasonably practicable, the use of available technologies to reduce the size of the steam plumes from the unit cooling towers. This will be a continuing obligations throughout the life of the plant.

21. SRP will, where practicable, work with El Paso Natural Gas Company to use the railroad easements for the installation of the new El Paso gas line.

22. Other than the Santan/RS 18 lines currently under construction, Applicant shall not construct additional Extra High Voltage transmission lines (115kV and above) into or out of the Santan site, including the substation on the site.

23. Applicant will replace all Town of Gilbert existing street sweepers with certified PM10 efficient equipment. A PM10 efficient street sweeper is a street sweeper that has been certified by the South Coast Air Quality

Management District (California) to comply with the District's performance standards under its Rule 1186 (which is the standard referenced by the Maricopa Association of Governments).

24. Applicant shall work in a cooperative effort with the Office of Environmental Health of the Arizona Department of Health Services to enhance its environmental efforts.

25. Applicant shall operate, improve and maintain the plant consistent with applicable environmental regulations and requirements of the Environmental Protection Agency, the Arizona Department of Environmental Quality, Maricopa County and the Town of Gilbert.

26. Applicant shall actively work in good faith with Maricopa County in its efforts to establish appropriate standards relative to the use of distillate fuels in Valley generating facilities.

27. Applicant shall install continuous emission monitoring equipment on the new units and will make available on its website emissions data from both the existing and new units according to EPA standards. Applicant shall provide information to the public on its website in order to assist the public in interpreting the data, and provide viable information in a reasonable time frame.

28. Applicant will comply with the provisions of the Intergovernmental Agreement dated April 25, 2000 between Applicant and the Town of Gilbert, as modified pursuant to this Certificate.

29. During the proceeding neighbors to the plant site raise significant concern about the impact of the plant expansion on residential property values. In performing each of the conditions in this order Applicant, in conjunction where applicable, with the Town of Gilbert and the plant site neighbors, shall consider and attempt to maximize the positive effect of its activities on the values of the homes in the surrounding neighborhoods.

30. Applicant shall construct the auxiliary boiler stack at such height as may be determined by air modeling requirements. Applicant shall situate the auxiliary boiler stack so that it is not visible from off the plant site.

31. Applicant will construct the heat recovery steam generators ("HRSG") approximately 15 feet below grade and will construct the HRSGs so that the overall height of the HRSG module from the natural grade is no more than 80 feet.

32. Applicant will complete the installation of the dry low NOX burners on the existing units prior to the construction of the new units.

33. Applicant shall not transfer this Certificate to any other entity for a period of 20 years from the date of approval by the Corporation Commission, other than as part of a financing transaction where operational responsibilities will remain with Applicant, and where Applicant will continue to operate the plant in accordance with this Certificate.

34. Applicant shall post on its website, when its air quality permit application is submitted to the Maricopa County Environmental Services Department. Also, Applicant shall post on its website any official notice that may be required to be posted in newspapers for its air quality permit application.

GRANTED this 14th day of February, 2001

ARIZONA POWER PLANT AND TRANSMISSION
LINE SITING COMMITTEE

Paul A. Bullis

By Paul A. Bullis
Its Chairman

Decision No. 63611

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE APPLICATION OF SALT RIVER PROJECT, OR THEIR ASSIGNEE(S), IN CONFORMANCE WITH THE REQUIREMENTS THE ARIZONA REVISED STATUTES 40-360.03 AND 40-360.06 FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE CONSTRUCTION OF NATRUAL GAS-FIRED, COMBINED CYCLE GENERATING FACILITIES AND ASSOCIATED INTRAPLANT TRANSMISSION LINES, SWITCHYARD IN GILBERT, ARIZONA, LOCATED NEAR AND WEST OF THE INTERSECTION OF VAL VISTA AND WARNER ROAD	Case No. 105 Docket No. L-00000B-00-0105 Decision No. 63611

The Arizona Corporation Commission (Commission) has conducted its review, as prescribed by A.R.S. § 40-360.07. Pursuant to A.R.S. § 40.360.07(B), the Commission, in compliance with A.R.S. § 40-360.06, and in balancing the broad public interest, the need for an adequate, economical and reliable supply of electric power with the desire to minimize the effect thereof on the environment and ecology of this state;

The Commission finds and concludes that the Certificate of Environmental Compatibility should be granted upon the additional and modified conditions stated herein.

35. The Santan Expansion Project shall be required to meet the Lowest Achievable Emission Rate (LAER) for Carbon Monoxide (CO), Nitrogen Oxides (NO_x), Volatile Organic Carbons (VOCs), and Particulate Matter less than ten micron in aerodynamic diameter (PM_{10}). The Santan Expansion Project shall be required to submit an air quality permit application requesting this LAER to the Maricopa County Environmental Services Department.

36. Due to the plant's location in a non-attainment area, the Applicant shall not use diesel fuel in the operation of any combustion turbine or heat recovery steam generator located at the plant.

37. In obtaining emissions reductions related to Carbon Monoxide (CO) emissions, Applicant shall where technologically feasible obtain those emission reductions onsite to the Santan Expansion Project.

38. Beginning upon commercial operation of the new units, Applicant shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emissions and the costs associated with each potential improvement. Commission Staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 60 days of receipt. Applicant shall install said improvements within 24 months of filing the review with the Commission, absent an order from the Commission directing otherwise.

39. Applicant shall provide $20,000 to the Pipeline Safety Revolving Fund on an annual basis, thus improving the overall safety of pipelines throughout the State of Arizona.

40. Where feasible, Applicant shall strive to incorporate local and in-state contractors in the construction of the three new generation units for the expansion projects.

41. Applicant shall construct a 10 foot high block wall surrounding the perimeter of the Santan plant, and appropriately landscape the area consistent with the surrounding neighborhood, unless otherwise agreed to by the Salt River Project and the Citizens Working Group.

APPROVED AS AMENDED BY ORDER OF THE ARIZONA CORPORATION COMMISSION

William A. Mundell

Chairman | Commissioner | Commissioner

IN WITNESS WHEREOF, I, Brian C. McNeil, Executive Secretary of the Arizona Corporation Commission, set my hand and cause the official seal of the Commission to be affixed this 1st day of May, 2001.

By

Brian C. McNeil
Executive Secretary

Dissent: ____________________

Attachment 2

Compliance Filing Condition 38 of CEC

0000131073

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

Arizona Corporation Commission
DOCKETED
OCT 14 2011
DOCKETED BY ne

IN THE MATTER OF SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT – CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE EXPANSION OF ITS SANTAN GENERATING STATION	DOCKET NO. L-00000B-00-0105-0000 DECISION NO. **72636** ORDER **COMPLIANCE FILING – CONDITION 38 OF CEC**

Open Meeting
October 11 and 12, 2011
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. Salt River Project Agricultural Improvement and Power District ("SRP") is an agricultural improvement district duly organized and existing under Title 48, Chapter 17, Arizona Revised Statutes, and is a political subdivision of the State of Arizona pursuant to Article 13, Section 7 of the Arizona Constitution.

2. In 2000, SRP applied for a Certificate of Environmental Compatibility ("CEC") authorizing the expansion of its Santan Generating Station ("Santan" or "Santan Plant"). The Santan Plant is located at 1005 South Val Vista Drive, Gilbert, Arizona which is near the intersection of Val Vista Drive and Warner Road in Gilbert, Arizona.

3. On May 1, 2001, the Arizona Corporation Commission ("ACC") granted the CEC for the Santan Plant expansion, subject to 41 conditions, in Decision No. 63611.

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4. Condition 38 required SRP to perform an air emissions assessment of the Santan Plant and to file a report with the ACC every five years that identifies any changes to the plant or the plant's operations that would reduce air emissions.

5. Condition 38 also requires the ACC Staff to review the SRP report and issue its findings, including economic feasibility,[1] within 60 days of the SRP report filing.

6. Condition 38 further requires that, absent an order from the Commission directing otherwise, SRP shall install the improvements listed in its report within 24 months of filing the review with the Commission.

7. The expansion of the Santan Plant was completed in 2006. This is SRP's first filing in compliance with Condition 38.

8. On July 1, 2011, pursuant to Commission Decision No. 63611, SRP filed its air emissions assessment report in compliance with Condition 38 of the Santan Expansion Project CEC.

9. SRP is requesting a Commission order stating that no additional air emission controls are required at the Santan Generating Station at this time.

10. SRP is also requesting that the Commission provide implementation guidance for future reviews to both SRP and Staff because SRP believes that there are ambiguities in Condition 38.

11. Santan was originally constructed in the 1970s as a plant with four combustion turbines, totaling approximately 368 MW. Decision No. 63611 approved the Santan Expansion Project with two new units capable of generating 825 MW.

12. SRP hired Sargent and Lundy, LLC ("S&L") to conduct the emissions assessment for the Santan Generating Station in order to meet Condition 38. S&L stated that, in its opinion, the current emission controls at Santan are appropriate. S&L recommended no additional new control technologies at Santan at this time.

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[1] Staff did not conduct an independent feasibility analysis but instead reviewed an analysis prepared by Sargent & Lundy, LLC, consultant to SRP.

13. The S&L assessment of nitrogen oxide ("NO_x") control technology identified three control options which are technically feasible today. They are: (1) combustor upgrades; (2) selective catalytic reduction ("SCR") system; and (3) SCR system and combustor upgrades. As part of the assessment, S&L conducted an economic evaluation for each of the three NO_x control options. The cost-effectiveness was assessed on a dollar-per-ton removed basis. This analysis was included in Table ES-2 on Page ES-6 of the S&L Assessment Report. A summary of the NO_x Control Evaluation of Units 1-4 is shown below in Table 1.

Table 1. Summary of NO_x Control Evaluation for Units 1-4[1]

Control Technology	Total Emissions Reduction (tpy)	Total Capital Cost ($)	Total Annual O&M Cost ($/year)	Total Annual Costs ($/year)	Average Cost-Effectiveness ($/ton)
SCR + Combustor Upgrades	154.5	$69,560,000	$3,802,000	$11,490,000	$74,369
SCR	154.5	$49,612,000	$3,751,000	$9,235,000	$59,773
Combustor Upgrades	103.1	$19,948,000	$75,000	$2,279,000	$22,104

[1]Values presented are combined totals for Santan Generating Station Units 1-4.

14. S&L explained in its report that the average cost-effectiveness of the three NO_x control options for Units 1-4 is high, ranging from $22,104 to $74,369 per ton. This cost is so high because the total cost of the control technology is large, but the resulting reduction in emissions is minimal. The reason for this is that the current emissions are extremely low because of the emission control improvements that SRP installed at Santan in the early 2000s and the units' limited use.

15. S&L conducted a review of publicly available evaluations of emission control cost-effectiveness. S&L found that it is common for permitting agencies[2] to declare that NO_x control options exceeding $10,000 per ton of NO_x removed are not considered cost-effective. The least-cost of the three options considered for Santan is $22,104 per ton for the combustor upgrades. This is over two times the cost of the $10,000 per ton NO_x limit for cost-effectiveness.

[2] The permitting agencies and documents used for the analysis are listed in Attachment 8 of the Sargent & Lundy Report.

16. The carbon monoxide ("CO") control technology assessment by S&L listed three technically feasible options. They are: (1) CO catalyst system upgrades; (2) CO catalyst system upgrades and combustor upgrades; and (3) combustor upgrades and existing CO catalyst system. The cost-effectiveness of controls was assessed on a dollar-per-ton removed basis. The summary of the CO Control Evaluation for Units 1-4 was included as Table ES-3 on Page ES-7 of the S&L Assessment. A summary of the CO Control Evaluation is shown below in Table 2.

Table 2. Summary of CO Control Evaluation for Units 1-4[(1)]

Control Technology	Total Emissions Reduction (tpy)	Total Capital Cost ($)	Total Annual O&M Cost ($/year)	Total Annual Costs ($/year)	Average Cost-Effectiveness ($/ton)
CO Catalyst System Upgrades	24.9	$7,784,000	$731,000	$1,591,000	$63,895
CO Catalyst System Upgrades and Combustor Upgrades	24.9	$27,732,000	$804,000	$3,868,000	$155,341
Combustor Upgrades and Existing CO Catalyst System	4.9	$19,948,000	$73,000	$2,277,000	$464,694

[(1)]Values presented are combined totals for Santan Generating Station Units 1-4.

17. S&L calculates the average annual cost-effectiveness of the three CO control options for Units 1-4 to range from $63,895 to $464,694 per ton of CO removed. The cost to remove additional CO is high because the cost of the control technology is substantial and the resulting air emission reductions are minimal. Similar to the case with NO_x controls, the current emissions are extremely low due to the emission control improvements that were made by SRP in the early 2000s and the limited use of the Santan units.

18. Permitting agencies often set levels based on which controls are considered cost-effective. S&L conducted a review of publicly available evaluations and S&L concluded that it is common for agencies to consider control options for CO to be "cost prohibitive" at levels above $4,000 per ton of CO removed. Since the three options identified by S&L cost from $63,895 to $464,694 per ton of CO removed, S&L concluded that the three options were cost-prohibitive.

19. SRP, in its filing, contends that there are additional reasons why no new emission controls should be required. SRP indicates that the Santan Generating Station is currently

operating under an air quality operating permit issued by the Maricopa County Air Quality Department ("MCAQD"). This permit includes separate combined emission limits for Units 5A, 5B, and 6. The permit also includes separate combined emission limits for Units 1-4. The permit was issued as part of the Santan Expansion Project.

20. As a result of the installation of emission controls on Units 1-4 and the advanced technology use for Units 5A, 5B and 6, the plant's capacity was increased by the Santan Expansion Project by 825 MW, but resulted in a decrease in total actual plant emissions. Actual emissions of the Santan Generating Station have stayed well below the combined emission limits for all regulated pollutants in the MCAQD permit.

21. The NO_x permit limit for Santan is 1,056 tons per year. In 2006-2009, the actual Santan NO_x output ranged from only 118 tons to 172 tons. SRP contends that since actual emissions are well below the permitted limits, there is no need for additional control technology at this time. SRP explains that emissions have already been significantly reduced. In 2000, NO_x from Units 1-4 exceeded 2,000 tons. After SRP installed dry low-NO_x burners, the total emissions of NO_x from Units 1-4 averaged 136 tons per year over the years 2005-2009.

22. SRP contends that after oxidation catalysts were installed on Units 1-4 the CO emissions were reduced significantly also. SRP claims that the reduced emission levels are also partially due to the low capacity factors of Units 1-4. SRP says that the capacity factor for Units 1-4 averaged 10.6 percent over the last five years and dropped to 7.5 percent during the last two years.

23. SRP claims that "externalities are not implicated" by SRP's proposal. SRP says that externalities are "often discussed in the context of a decision to build a new power plant." SRP believes that "SRP's proposal does not have any associated externalities since no changes at the Santan Generating Station are recommended at this time."

24. SRP included in its application charts that demonstrate that the NO_X emissions from Units 1-4 are less than 0.1 percent of total Maricopa County emissions and the CO emissions for Units 1-4 are less than 0.01 percent of total Maricopa County emissions. SRP concludes that the

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control options considered in the S&L report are, therefore, very unlikely to have any measurable impact on Maricopa County's air quality.

25. SRP presented the S&L report to the local Santan Neighborhood Committee ("Committee") and is comprised of representatives from the Arizona Department of Health Services, Maricopa County Air Quality Department, the Town of Gilbert, adjacent homeowners associations (Cottonwood Crossings, Finley Farms South, Rancho Cimarron, Silverstone Ranch and Western Skies), the county island near SGS and a resident of Gilbert who is a registered professional engineer. The Committee was formed as a condition of the Santan Expansion Project CEC. The Committee issued a letter supporting the S&L recommendations that SRP not be required to install additional air emission controls at this time.

26. In its filing, SRP requests guidance from the Commission related to the future implementation of Condition 38. SRP questions whether the deadlines are feasible and how the compliance process should work.

27. Condition 38 states:

> *Beginning upon commercial operation of the new units, Applicant shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emissions and the costs associated with each potential improvement. Commission Staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 60 days of receipt. Applicant shall install said improvements within 24 months of filing the review with the Commission, absent an order from the Commission directing otherwise.*

28. SRP claims that, absent an order from the Commission, there is no clear guidance for SRP about which technologies to install. Further, lacking clear guidance, duplicative or inconsistent technologies could be required to be installed.

29. SRP notes that Condition 38 requires the installation of the controls within 24 months of filing the report with the Commission. SRP contends that meeting the 24-month deadline is not possible considering the time for permitting, acquisition of equipment and other requirements.

30. SRP described, in its application, the time delays related to 45-day EPA review periods, 30-day public notice periods and revisions that can take over a year to complete. SRP mentions that, due to the recent economic downturn, the air quality permitting staff at MCAQCD has been reduced significantly. SRP also suggests that work on the unit might have to be staged due to the need to have the units available during certain critical peak periods.

31. SRP also mentions that Condition 38 does not specify if the review period would continue based on the date Units 5 and 6 were put into service or on a new date based on the in-service date of the new control devices. SRP would prefer the latter option.

32. SRP is requesting that the Commission approve an order that establishes the following procedure for future five-year reviews:

- Installation of any emission controls would only be required 48 months after an order issued by the Commission identifying the specific air emission controls and directing their installation, and

- In the event that new controls or a new operating methodology is required, the in-service date of any new control technology or operating methodology will be the effective date for the next five-year review period.

33. In its filing, SRP says that externalities are "often discussed in the context of a decision to build a new power plant." Staff agrees that this is correct, but that does not mean that an analysis of externalities should be excluded from the economic analysis and decision of whether or not to add new emission controls to existing power plants. In fact, Staff believes that the externalities of power plant operations should be an integral part of such an economic analysis.

34. Therefore, Staff disagrees with SRP's assertion that "SRP's proposal does not have any associated externalities since no changes at the Santan Generating Station are recommended at this time."

35. When conducting a cost-benefit analysis of the possible addition of new emission controls, it is not enough to merely consider the "cost" portion of the equation and forget the "benefit" portion which includes the benefits to society of eliminating the externality costs of the tons of emissions to be removed by the proposed emission controls that are being evaluated.

. . .

36. Staff recommends that the Commission order that in future SRP reviews of the Santan Generating facility, SRP should incorporate the monetized value of all externalities that would be eliminated due to new emissions controls that are being evaluated in response to Condition 38 in the benefits portion of the cost-benefit analysis. SRP should use nationally recognized values for the monetized externality costs of pollutants coming from Santan.

37. Staff has reviewed the study completed by S&L. Staff concurs with S&L and SRP that the current emission controls at Santan are appropriate and that no new control technologies are appropriate at this time.

38. Staff notes that the two newest units, Units 5A, 5B and 6 already contain the best-state-of-the-art controls that would apply for a new plant today. Staff also agrees with S&L and SRP that there is no need for any changes to fuel storage tanks, abrasive blasting equipment, emergency engines, or cooling towers. Finally, Staff agrees that there is no need for upgrades of Units 1-4 because any costs of such upgrades would be significantly greater than any benefits.

39. Staff has reviewed SRP's concerns about guidance for future implementation of the requirements of Condition 38. Staff concurs with SRP's proposed procedure for future five-year reviews, with minor wording modifications, and recommends that the Commission adopt SRP's proposed procedure as modified in the order issued relative to this matter.

40. Staff has recommended that Condition 38 be modified to read as follows:

> Beginning upon commercial operation of the new units, Applicant shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emission and the costs associated with each potential improvement. Commission Staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 90 days of receipt. Applicant shall install said improvements within 48 months after an order issued by the Commission identifying the specific air emission controls and directing their installation. In the event that new controls or a new operating methodology are required, the in-service date of any new control technology or operating methodology will be the starting date for the next five-year review period. If no new operating methodology is required, the starting date for the next five-year review period shall be the effective date of the Commission's decision regarding the previous five-year review report.

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CONCLUSIONS OF LAW

1. The Commission has jurisdiction over Salt River Project and the subject matter contained herein pursuant to A.R.S. §§ 40-252 and 40-360 *et. seq.*

2. Notice of the proceeding has been provided in the manner prescribed by law.

3. The Commission, having reviewed and considered the application and Staff's Memorandum dated August 29, 2011, concludes that is in the public interest to approve the Salt River Project compliance filing and modify Decision No. 63611 Condition 38 as specified in this order.

ORDER

IT IS THEREFORE ORDERED that Salt River Project Agricultural Improvement and Power District shall not be required to install any improvements at the Santan Generating facility at this time.

IT IS FURTHER ORDERED that Decision No. 63611 is hereby modified to revise Condition 38 of the Certificate of Environmental Compatibility to state as follows:

> Beginning upon commercial operation of the new units, Applicant shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emission and the costs associated with each potential improvement. Commission Staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 90 days of receipt. Applicant shall install said improvements within 48 months after an order issued by the Commission identifying the specific air emission controls and directing their installation. In the event that new controls or a new operating methodology are required, the in-service date of any new control technology or operating methodology will be the starting date for the next five-year review period. If no new operating methodology is required, the starting date for the next five-year review period shall be the effective date of the Commission's decision regarding the previous five-year review report.

IT IS FURTHER ORDERED that in the future Salt River Project Agricultural Improvement and Power District reviews of the Santan Generating facility, Salt River Project Agricultural Improvement and Power District shall incorporate the monetized value of all externalities that would be eliminated due to new emissions controls that are being evaluated in response to Condition 38 into the benefits portion of the cost-benefit analysis. Salt River Project Agricultural Improvement and Power District shall use nationally recognized values for the monetized externality costs of pollutants coming from Santan.

IT IS FURTHER ORDERED that all other provisions of Decision No. 63611 remain in full force and effect.

IT IS FURTHER ORDERED that this Decision become effective immediately.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 14th day of October, 2011.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT: ____________________

DISSENT: ____________________

SMO:RTW:lhm\CH

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Attachment 3

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

NO_X RBLC Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (NO DUCT BURNING)	NATURAL GAS	154 MW	NITROGEN DIOXIDE (NO2)	SCR	2 PPMVD
VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (WITH DUCT BURNING)	NATURAL GAS	154 MW	NITROGEN DIOXIDE (NO2)	SCR	2 PPMVD
VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (NO DUCT BURNING)	NATURAL GAS	154 MW	NITROGEN DIOXIDE (NO2)	SCR	2 PPMVD
VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (WITH DUCT BURNING)	NATURAL GAS	154 MW	NITROGEN DIOXIDE (NO2)	SCR	2 PPMVD
BLYTHE ENERGY PROJECT II	CA	4/25/2007	2 COMBUSTION TURBINES	NATURAL GAS	170 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
OTAY MESA ENERGY CENTER LLC	CA	7/22/2009	GAS TURBINE COMBINED CYCLE	NATURAL GAS	171.7 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD@15% OXYGEN
APPLIED ENERGY LLC	CA	3/20/2009	GAS TURBINE COMBINED CYCLE	NATURAL GAS	0	NITROGEN OXIDES (NOX)	SCR	2 PPM
AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NO DUCT BURNING)	NATURAL GAS	180 MW	NITROGEN OXIDES (NOX)	SCR, DLN COMBUSTORS	2 PPMVD
AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (WITH DUCT BURNING)	NATURAL GAS	180 MW	NITROGEN OXIDES (NOX)	SCR, DLN COMBUSTORS	2 PPMVD
AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NO DUCT BURNING)	NATURAL GAS	180 MW	NITROGEN OXIDES (NOX)	SCR, DLN COMBUSTORS	2 PPMVD
AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (WITH DUCT BURNING)	NATURAL GAS	180 MW	NITROGEN OXIDES (NOX)	SCR, DLN COMBUSTORS	2 PPMVD
COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES	NATURAL GAS	172 MW	NITROGEN OXIDES (NOX)	SCR, DLN COMBUSTORS	2 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES	NATURAL GAS	154 MW	NITROGEN OXIDES (NOX)	SCR, DLN COMBUSTORS	2 PPMVD
MOUNTAINVIEW POWER COMPANY LLC	CA	4/21/2006	COMBUSTION TURBINES	NATURAL GAS	175.7 MW EA.	NITROGEN OXIDES (NOX)	1991 DLN COMBUSTORS, SCR	2 PPMVD
CPV TOWANTIC, LLC	CT	11/30/2015	COMBINED CYCLE POWER PLANT	NATURAL GAS	21200000 MMBTU/12 MONTHS	NITROGEN OXIDES (NOX)	SCR	2 PPMVD @15% O2
CPV TOWANTIC, LLC	CT	11/30/2015	COMBINED CYCLE POWER PLANT	NATURAL GAS	21200000 MMBTU/YR	NITROGEN OXIDES (NOX)	SCR	2 PPMVD @15% O2
GARRISON ENERGY CENTER	DE	1/30/2013	UNIT 1	NATURAL GAS	2260 MILLION BTUS	NITROGEN OXIDES (NOX)	LOW NOX COMBUSTORS, SCR	2 PPM
FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	NATURAL GAS	2333 MMBTU/H	NITROGEN OXIDES (NOX)	DLN, SCR, AND WATER INJECTION	2 PPMVD @15%O2
FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	7/30/2008	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	NATURAL GAS	2333 MMBTU/H	NITROGEN OXIDES (NOX)	DLN, SCR	2 PPMVD (GAS)
CANE ISLAND POWER PARK	FL	9/8/2008	300 MW COMBINED CYCLE COMBUSTION TURBINE	NATURAL GAS	1860 MMBTU/H	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
POLK POWER STATION	FL	10/14/2012	COMBINE CYCLE POWER BLOCK (4 ON 1)	NATURAL GAS	1160 MW	NITROGEN OXIDES (NOX)	SCR/DLN	2 PPMVD @15% O2
OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	COMBINED-CYCLE ELECTRIC GENERATING UNIT	NATURAL GAS	3096 MMBTU/HR PER TURBINE	NITROGEN OXIDES (NOX)	SCR, DLN, AND WET INJECTION	2 PPMVD@15% O2
MARSHALLTOWN GENERATING STATION	IA	4/14/2014	COMBUSTION TURBINE #1 - COMBINED CYCLE	NATURAL GAS	2258 MMBTU/HR	NITROGEN OXIDES (NOX)	LOW-NOX BURNERS AND SCR	2 PPM

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
MARSHALLTOWN GENERATING STATION	IA	4/14/2014	COMBUSTION TURBINE #2 - COMBINED CYCLE	NATURAL GAS	2258 MMBTU/HR	NITROGEN OXIDES (NOX)	SCR, LOW-NOX BURNER	2 PPM
LANGLEY GULCH POWER PLANT	ID	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	NATURAL GAS (ONLY)	2375.28 MMBTU/H	NITROGEN OXIDES (NOX)	SCR, DLN, GOOD COMBUSTION PRACTICES (GCP)	2 PPMVD
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	NATURAL GAS	2300 MMBTU/H	NITROGEN OXIDES (NOX)	SCR AND DRY LOW NOX BURNERS	2 PPMVD
SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	2449 MMBTU/H	NITROGEN OXIDES (NOX)	DLN COMBUSTORS, SCR	2 PPMVD @ 15% O2
CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	725 MEGAWATT	NITROGEN OXIDES (NOX)	DLN COMBUSTORS, SCR	2 PPMVD @ 15% O2
WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	NATURAL GAS	1000 MW	NITROGEN OXIDES (NOX)	DLN COMBUSTOR TURBINE DESIGN, USE OF PIPELINE QUALITY NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2 PPMVD @ 15% O2
MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	286 MW	NITROGEN OXIDES (NOX)	GOOD COMBUSTION PRACTICES, DLN COMBUSTOR DESIGN AND SCR	2 PPMVD @ 15% O2
KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	235 MW	NITROGEN OXIDES (NOX)	GOOD COMBUSTION PRACTICES, DLN	2 PPMVD @ 15% O2

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
							COMBUSTOR DESIGN AND SCR	
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG	NATURAL GAS	2237 MMBTU/H	NITROGEN OXIDES (NOX)	DLN BURNER AND SCR	2 PPM
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG AND DUCT BURNER (DB)	NATURAL GAS	2486 MMBTU/H	NITROGEN OXIDES (NOX)	DLN BURNER AND SCR	2 PPM
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE -SIEMENS TURBINE WITHOUT DUCT BURNER	NATURAL GAS	33691 MMCF/YR	NITROGEN OXIDES (NOX)	SCR AND DLN	2 PPMVD@ 15% O2
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	NATURAL GAS	33691 MMCF/YR	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	NATURAL GAS	33691 MMCF/YR	NITROGEN OXIDES (NOX)	SCR AND DLN	2 PPMVD@15%O2
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	NATURAL GAS	33691 MMCF/YR	NITROGEN OXIDES (NOX)	SCR AND DLN	2 PPMVD@15%O2
WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	COMBINED CYCLE COMBUSTION	NATURAL GAS	20282 MMCF/YR	NITROGEN OXIDES (NOX)	SCR AND USE OF NATURAL GAS A	2 PPMVD@15%O2

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
			TURBINE WITHOUT DUCT BURNER				CLEAN BURNING FUEL	
CAITHNES BELLPORT ENERGY CENTER	NY	5/10/2006	COMBUSTION TURBINE	NATURAL GAS	2221 MMBUT/H	NITROGEN OXIDES (NOX)	SCR	2 PPMVD@15%02
ATHENS GENERATING PLANT	NY	1/19/2007	FUEL COMBUSTION (GAS)	NATURAL GAS	3100 MMBTU/H	NITROGEN OXIDES (NOX)	SCR AND DLN	2 PPMVD @ 15% O2
OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 COMBINED CYCLE COMBUSTION TURBINES-SIEMENS, WITHOUT DUCT BURNERS	NATURAL GAS	515600 MMSCF/ROLLING 12-MONTHS	NITROGEN OXIDES (NOX)	SCR AND DLN; LEAN FUEL TECHNOLOGY	2 PPM
OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 COMBINED CYCLE COMBUSTION TURBINES-SIEMENS, WITH DUCT BURNERS	NATURAL GAS	51560 MMSCF/ROLLING 12-MO	NITROGEN OXIDES (NOX)	SCR AND DLN; LEAN FUEL TECHNOLOGY	2 PPM
OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 COMBINED CYCLE COMBUSTION TURBINES-MITSUBISHI, WITHOUT DUCT BURNERS	NATURAL GAS	47917 MMSCF/ROLLING 12-MO	NITROGEN OXIDES (NOX)	SCR AND DLN; LEAN FUEL TECHNOLOGY	2 PPM
OREGON CLEAN ENERGY CENTER	OH	6/18/2013	2 COMBINED CYCLE COMBUSTION TURBINES-MITSUBISHI, WITH DUCT BURNERS	NATURAL GAS	47917 MMSCF/ROLLING 12-MO	NITROGEN OXIDES (NOX)	SCR AND DLN; LEAN FUEL TECHNOLOGY	2 PPM
MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	NATURAL GAS	360 MW	NITROGEN OXIDES (NOX)	SCR AND DLN	2 PPMVD@15% O2
MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	NATURAL GAS	360 MW	NITROGEN OXIDES (NOX)	SCR AND DLN	2 PPMVD@15% O2

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
CARTY PLANT	OR	12/29/2010	COMBINED CYCLE NATURAL GAS-FIRED ELECTRIC GENERATING UNIT	NATURAL GAS	2866 MMBTU/H	NITROGEN OXIDES (NOX)	SCR	2 PPM@15%O2
TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	MITSUBISHI M501-GAC COMBUSTION TURBINE, COMBINED CYCLE CONFIGURATION WITH DUCT BURNER.	NATURAL GS	2988 MMBTU/H	NITROGEN OXIDES (NOX)	DLN COMBUSTORS, SCR, WATER INJECTION WHEN COMBUSTING ULSD;	2 PPMDV AT 15% O2
MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	COMBINED-CYCLE TURBINES (2) - NATURAL GAS FIRED	NATURAL GAS	3277 MMBTU/H	NITROGEN OXIDES (NOX)	DLN COMBUSTORS, SCR	2 PPMVD
MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	COMBINED CYCLE POWER BLOCKS 472 MW - (2)	NATURAL GAS	0	NITROGEN OXIDES (NOX)	SCR	2 PPMDV
SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	COMBINED CYCLE COMBUSTION TURBINE AND DUCT BURNER (3)	NATURAL GAS	2538000 MMBTU/H	NITROGEN OXIDES (NOX)	SCR	2 PPM
HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 AND #2	NATURAL GAS	3.4 MMCF/HR	NITROGEN OXIDES (NOX)	SCR	2 PPMVD @ 15% O2
FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	TURBINE, COMBINED CYCLE UNIT (SIEMENS 5000)	NATURAL GAS	2267 MMBTU/H	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
JOHNSONVILLE COGENERATION	TN	4/19/2016	NATURAL GAS-FIRED COMBUSTION TURBINE WITH HRSG	NATURAL GAS	1339 MMBTU/HR	NITROGEN OXIDES (NOX)	GOOD COMBUSTION DESIGN AND PRACTICES, SCR	2 PPMVD @ 15% O2
PATTILLO BRANCH POWER PLANT	TX	6/17/2009	ELECTRICITY GENERATION	NATURAL GAS	350 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
NATURAL GAS-FIRED POWER GENERATION FACILITY	TX	6/22/2009	ELECTRICITY GENERATION	NATURAL GAS	250 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
MADISON BELL ENERGY CENTER	TX	8/18/2009	ELECTRICITY GENERATION	NATURAL GAS	275 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
KING POWER STATION	TX	8/5/2010	TURBINE	NATURAL GAS	1350 MW	NITROGEN OXIDES (NOX)	DLN BURNERS AND SCR	2 PPMVD AT 15% O2
THOMAS C. FERGUSON POWER PLANT	TX	9/1/2011	NATURAL GAS-FIRED TURBINES	NATURAL GAS	390 MW	NITROGEN OXIDES (NOX)	DLN COMBUSTORS, SCR	2 PPMVD
CHANNEL ENERGY CENTER LLC	TX	10/15/2012	COMBINED CYCLE TURBINE	NATURAL GAS	180 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
DEER PARK ENERGY CENTER	TX	9/26/2012	COMBINED CYCLE TURBINE	NATURAL GAS	180 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
ES JOSLIN POWER PLANT	TX	9/12/2012	COMBINED CYCLE GAS TURBINE	NATURAL GAS	195 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
PINECREST ENERGY CENTER	TX	11/12/2013	COMBINED CYCLE TURBINE	NATURAL GAS	700 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	ALSTOM TURBINE	NATURAL GAS	230.7 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
FREEPORT LNG PRETREATMENT FACILITY	TX	7/16/2014	COMBUSTION TURBINE	NATURAL GAS	87 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
CEDAR BAYOU ELECTRIC GENERATION STATION	TX	8/29/2014	COMBINED CYCLE NATURAL GAS TURBINES	NATURAL GAS	225 MW	NITROGEN OXIDES (NOX)	DLN, SCR	2 PPM
LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) COMBINED CYCLE TURBINES	NATURAL GAS	650 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
SAND HILL ENERGY CENTER	TX	9/13/2013	NATURAL GAS-FIRED COMBINED CYCLE TURBINES	NATURAL GAS	173.9 MW	NITROGEN OXIDES (NOX)	SCR	2 PPM
VICTORIA POWER STATION	TX	12/1/2014	COMBINED CYCLE TURBINE	NATURAL GAS	197 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
TRINIDAD GENERATING FACILITY	TX	11/20/2014	COMBINED CYCLE TURBINE	NATURAL GAS	497 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO$_X$ Emission Limit
TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) COMBINED CYCLE TURBINES	NATURAL GAS	274 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) COMBINED CYCLE TURBINES	NATURAL GAS	240 MW	NITROGEN OXIDES (NOX)	SCR	2 PPMVD
COLORADO BEND ENERGY CENTER	TX	4/1/2015	COMBINED-CYCLE GAS TURBINE ELECTRIC GENERATING FACILITY	NATURAL GAS	1100 MW	NITROGEN OXIDES (NOX)	SCR AND OXIDATION CATALYST	2 PPMVD @ 15% O2
EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	COMBINED CYCLE TURBINES (>25 MW) â€“ NATURAL GAS	NATURAL GAS	210 MW	NITROGEN OXIDES (NOX)	SCR	2 PPM
LON C. HILL POWER STATION	TX	10/2/2015	COMBINED CYCLE TURBINES (>25 MW)	NATURAL GAS	195 MW	NITROGEN OXIDES (NOX)	SCR	2 PPM
FGE EAGLE PINES PROJECT	TX	11/4/2015	COMBINED CYCLE TURBINES (>25 MW)	NATURAL GAS	321 MW	NITROGEN OXIDES (NOX)	SCR	2 PPM
NECHES STATION	TX	3/24/2016	COMBINED CYCLE & COGENERATION	NATURAL GAS	231 MW	NITROGEN OXIDES (NOX)	SCR	2 PPM
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	COMBINED CYCLE & COGENERATION	NATURAL GAS	231 MW	NITROGEN OXIDES (NOX)	SCR	2 PPM
WARREN COUNTY POWER PLANT - DOMINION	VA	12/17/2010	COMBINED CYCLE TURBINE & DUCT BURNER, 3	NATURAL GAS	2996 MMBTU/H	NITROGEN OXIDES (NOX)	TWO-STAGE, DLN COMBUSTOR, SCR	2 PPMVD@15%O2
BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	NATURAL GAS	3442 MMBTU/H	NITROGEN OXIDES (NOX)	SCR AND ULTRA LOW NOX BURNERS.	2 PPMVD @ 15% O2

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
ELK HILLS POWER LLC	CA	1/12/2006	COMBUSTION TURBINE GENERATOR, 2 UNITS (NORMAL OPERATION)	NATURAL GAS	166 MW	NITROGEN OXIDES (NOX)	SCR OR SCONOX, DLN COMBUSTORS	2.5 PPMVD
HIGH DESERT POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE GENERATORS (NORMAL OPERATION)	NATURAL GAS	190 MW	NITROGEN OXIDES (NOX)	DLN COMBUSTORS, SCR	2.5 PPMVD
NRG ENERGY CENTER DOVER	DE	10/31/2012	UNIT 2- KD1	NATURAL GAS	655 MMBTU/H	NITROGEN OXIDES (NOX)	SCR	2.5 PPM
LIVE OAKS POWER PLANT	GA	4/8/2010	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	NATURAL GAS	600 MW	NITROGEN OXIDES (NOX)	DLN COMBUSTORS, SCR	2.5 PPM@15%02
ROCKY MOUNTAIN ENERGY CENTER, LLC	CO	5/2/2006	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	NATURAL GAS	300 MW	NITROGEN OXIDES (NOX)	LOW NOX BURNERS AND SCR	3 PPM @ 15% O2
PUEBLO AIRPORT GENERATING STATION	CO	7/22/2010	FOUR COMBINED CYCLE COMBUTION TURBINES	NATURAL GAS	373 MMBTU/H	NITROGEN OXIDES (NOX)	DLN COMBUSTORS, SCR	3 PPMVD AT 15% O2
THETFORD GENERATING STATION	MI	7/25/2013	FGCCA OR FGCCB--4 NAT. GAS FIRED CTG W/ DB FOR HRSG	NATURAL GAS	2587 MMBTU/H HEAT INPUT, EACH CTG	NITROGEN OXIDES (NOX)	DLN BURNERSS, SCR	3 PPMV
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 COMBINED CYCLE CTGS WITH HRSGS WITH DUCT BURNERS	NATURAL GAS	647 MMBTU/H FOR EACH CTGHRSG	NITROGEN OXIDES (NOX)	DLN BURNERS, SCR	3 PPM
FAIRBAULT ENERGY PARK	MN	6/5/2007	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	NATURAL GAS	1758 MMBTU/H	NITROGEN OXIDES (NOX)	DLN COMBUSTION FOR NG; WATER INJECTION FOR NO.2 OIL; SCR	3 PPMVD
DUKE ENERGY HANGING ROCK	OH	12/18/2012	TURBINES (4) (MODEL GE 7FA)	NATURAL GAS	172 MW	NITROGEN OXIDES (NOX)	DLN BURNERS, SCR	3 PPM

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
ENERGY			DUCT BURNERS OFF					
DUKE ENERGY HANGING ROCK ENERGY	OH	12/18/2012	TURBINES (4) (MODEL GE 7FA) DUCT BURNERS ON	NATURAL GAS	172 MW	NITROGEN OXIDES (NOX)	DLN BURNERS, SCR	3 PPM
CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	COMBINED CYCLE TURBINE (EP01)	NATURAL GAS	40 MW	NITROGEN OXIDES (NOX)	SCR	3 PPMV AT 15% O2
CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	COMBINED CYCLE TURBINE (EP02)	NATURAL GAS	40 MW	NITROGEN OXIDES (NOX)	SCR	3 PPMV AT 15% O2
LAWTON ENERGY COGEN FACILITY	OK	12/12/2006	COMBUSTION TURBINE AND DUCT BURNER			NITROGEN OXIDES (NOX)	DLN BURNERS, SCR	3.5 PPMVD
NELSON ENERGY CENTER	IL	12/28/2010	ELECTRIC GENERATION FACILITY	NATURAL GAS	220 MW EACH	NITROGEN OXIDES (NOX)	DLN BURNERS, SCR	4.5 PPMVD @ 15% O2
INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	GE LM6000PF-25 TURBINES (4)	NATURAL GAS	59900 HP ISO	NITROGEN OXIDES (NOX)	DLN BURNERS, SCR	5 PPMDV
INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	FUEL COMBUSTION	NATURAL GAS	59900 HP	NITROGEN OXIDES (NOX)	DLN BURNERS, SCR.	5 PPM
BAYPORT COMPLEX	TX	9/5/2013	(4) COGENERATION TURBINES	NATURAL GAS	90 MW	NITROGEN OXIDES (NOX)	DLN AND CLOSED LOOP EMISSIONS CONTROLS (CLEC)	5 PPMVD
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	SIMPLE CYCLE ELECTRICAL GENERATION GAS TURBINES 15.210	NATURAL GAS	34 MW	NITROGEN OXIDES (NOX)	SCR	5 PPM
SUMPTER POWER PLANT	MI	11/17/2011	COMBINED CYCLE COMBUSTION TURBINE W/ HRSG	NATURAL GAS	130 MW ELECTRICAL OUTPUT	NITROGEN OXIDES (NOX)	LOW NOX BURNERS	9 PPM

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	NO_X Emission Limit
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	REFRIGERATION COMPRESSION TURBINES	NATURAL GAS	10 M TONNES/YR	NITROGEN OXIDES (NOX)	DLN BURNERS AND GOOD COMBUSTION PRACTICES	9 PPM
PROGRESS BARTOW POWER PLANT	FL	1/26/2007	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	NATURAL GAS	1972 MMBTU/H	NITROGEN OXIDES (NOX)	WATER INJECTION	15 PPMVD UNCORRECTED
CORPUS CHRISTI LIQUEFACTION PLANT	TX	9/12/2014	REFRIGERATION COMPRESSOR TURBINES	NATURAL GAS	40000 HP	NITROGEN OXIDES (NOX)	DRY LOW EMISSION COMBUSTORS	25 PPMVD

CO RBLC Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
CPV TOWANTIC, LLC	CT	11/30/2015	COMBINED CYCLE POWER PLANT	NATURAL GAS	21200000 MMBTU/12 MONTHS	CARBON MONOXIDE	OXIDATION CATALYST	0.9 PPMVD @15% O2
CPV TOWANTIC, LLC	CT	11/30/2015	COMBINED CYCLE POWER PLANT	NATURAL GAS	21200000 MMBTU/YR	CARBON MONOXIDE	OXIDATION CATALYST	0.9 PPMVD @15% O2
WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER	NATURAL GAS	20282 MMCF/YR	CARBON MONOXIDE	OXIDATION CATALYST; NATURAL GAS A CLEAN BURNING FUEL	0.9 PPMVD@15%O2
AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NORMAL OPERATION, NO DUCT BURNING)	NATURAL GAS	180 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	1.5 PPMVD
AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NORMAL OPERATION, NO DUCT BURNING)	NATURAL GAS	180 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	1.5 PPMVD
PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	154 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	1.5 PPMVD
WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITHOUT DUCT FIRING	NATURAL GAS	270 MW	CARBON MONOXIDE	PIPELINE QUALITY NATURAL GAS, OXIDATION CATALYST AND EFFICIENT CT DESIGN	1.5 PPMVD @ 15% O2
WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	20282 MMCF/YR	CARBON MONOXIDE	OXIDATION CATALYST AND USE OF NATURAL GAS A CLEAN BURNING FUEL	1.5 PPMVD@15%O2

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
WARREN COUNTY POWER PLANT - DOMINION	VA	12/17/2010	COMBINED CYCLE TURBINE & DUCT BURNER, 3	NATURAL GAS	2996 MMBTU/H	CARBON MONOXIDE	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES.	1.5 PPMVD
BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	NATURAL GAS	3442 MMBTU/H	CARBON MONOXIDE	OXIDATION CATALYST; GOOD COMBUSTION PRACTICES.	1.5 PPMVD
BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	THREE MITSUBISHI M501 GAC TURBINES (3,442 MMBTU/HR EACH)	NATURAL GAS	0 S	CARBON MONOXIDE	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1.5 PPMVD
PLANT MCDONOUGH COMBINED CYCLE	GA	1/7/2008	COMBINED CYCLE COMBUSTION TURBINE	NATURAL GAS	254 MW	CARBON MONOXIDE	OXIDATION CATALYST	1.8 PPM @ 15% O2
VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (NORMAL OPERATION, NO DUCT BURNING)	NATURAL GAS	154 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	2 PPMVD
VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (NORMAL OPERATION, NO DUCT BURNING)	NATURAL GAS	154 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	2 PPMVD
AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #1 (NORMAL OPERATION, WITH DUCT BURNING)	NATURAL GAS	180 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	2 PPMVD
AVENAL ENERGY PROJECT	CA	6/21/2011	COMBUSTION TURBINE #2 (NORMAL OPERATION, WITH DUCT BURNING)	NATURAL GAS	180 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	2 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
LIVE OAKS POWER PLANT	GA	4/8/2010	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	NATURAL GAS	600 MW	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES AND CATALYTIC OXIDATION	2 PPM@15%02
MARSHALLTOWN GENERATING STATION	IA	4/14/2014	COMBUSTION TURBINE #1 - COMBINED CYCLE	NATURAL GAS	2258 MMBTU/HR	CARBON MONOXIDE	CATALYTIC OXIDIZER	2 PPM
MARSHALLTOWN GENERATING STATION	IA	4/14/2014	COMBUSTION TURBINE #2 - COMBINED CYCLE	NATURAL GAS	2258 MMBTU/HR	CARBON MONOXIDE	CO CATALYST	2 PPM
LANGLEY GULCH POWER PLANT	ID	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	NATURAL GAS (ONLY)	2375.28 MMBTU/H	CARBON MONOXIDE	CO CATALYST DRY LOW NOX (DLN), GOOD COMBUSTION PRACTICES (GCP)	2 PPMVD
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	NATURAL GAS	2300 MMBTU/H	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD
SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	2449 MMBTU/H	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD@15% O2
CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	725 MEGAWATT	CARBON MONOXIDE	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	2 PPMVD @ 15% O2
MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	286 MW	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST	2 PPMVD @ 15% O2

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	235 MW	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST	2 PPMVD @ 15% O2
WEST DEPTFORD ENERGY	NJ	5/6/2009	TURBINE, COMBINED CYCLE	NATURAL GAS	17298 MMFT3/YR	CARBON MONOXIDE	CO OXIDATION CATALYST	2 PPMVD@15%O2
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE -SIEMENS TURBINE WITHOUT DUCT BURNER	NATURAL GAS	33691 MMCF/YR	CARBON MONOXIDE	CO OXIDATION CATALYST, GOOD COMBUSTION PRACTICES; NATURAL GAS AS CLEAN BURNING FUEL	2 PPMVD@15% O2
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	NATURAL GAS	33691 MMCF/YR	CARBON MONOXIDE	OXIDATION CATALYST AND USE OF ONLY NATURAL GAS A CLEAN BURNING FUEL	2 PPMVD
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	NATURAL GAS	33691 MMCF/YR	CARBON MONOXIDE	CO OXIDATION CATALYST, GOOD COMBUSTION PRACTICES; NATURAL GAS AS CLEAN BURNING FUEL	2 PPMVD@15%O2
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	NATURAL GAS	33691 MMCF/YR	CARBON MONOXIDE	CO OXIDATION CATALYST, GOOD COMBUSTION PRACTICES; NATURAL GAS AS CLEAN BURNING FUEL	2 PPMVD@15%O2
CAITHNES BELLPORT ENERGY CENTER	NY	5/10/2006	COMBUSTION TURBINE	NATURAL GAS	2221 MMBUT/H	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD@15%02

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	NATURAL GAS	360 MW	CARBON MONOXIDE	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICE.	2 PPMVD@15%O2
MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	NATURAL GAS	360 MW	CARBON MONOXIDE	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES.	2 PPMVD@15% O2
MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	COMBINED-CYCLE TURBINES (2) - NATURAL GAS FIRED	NATURAL GAS	3277 MMBTU/H	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD
MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	COMBINED CYCLE POWER BLOCKS 472 MW - (2)	NATURAL GAS	0	CARBON MONOXIDE	CO CATALYST	2 PPMDV
SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	COMBINED CYCLE COMBUSTION TURBINE AND DUCT BURNER (3)	NATURAL GAS	2538000 MMBTU/H	CARBON MONOXIDE	OXIDATION CATALYST	2 PPM
HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 AND #2	NATURAL GAS	3.4 MMCF/HR	CARBON MONOXIDE	CO CATALYST	2 PPMVD @ 15% OXYGEN
JOHNSONVILLE COGENERATION	TN	4/19/2016	NATURAL GAS-FIRED COMBUSTION TURBINE WITH HRSG	NATURAL GAS	1339 MMBTU/HR	CARBON MONOXIDE	GOOD COMBUSTION DESIGN AND PRACTICES, OXIDATION CATALYST	2 PPMVD @ 15% O2
PATTILLO BRANCH POWER PLANT	TX	6/17/2009	ELECTRICITY GENERATION	NATURAL GAS	350 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD
KING POWER STATION	TX	8/5/2010	TURBINE	NATURAL GAS	1350 MW	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES WITH AN OXIDATION CATALYST	2 PPMVD AT 15% O2

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
PINECREST ENERGY CENTER	TX	11/12/2013	COMBINED CYCLE TURBINE	NATURAL GAS	700 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD
FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	ALSTOM TURBINE	NATURAL GAS	230.7 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD
CEDAR BAYOU ELECTRIC GENERATION STATION	TX	8/29/2014	COMBINED CYCLE NATURAL GAS TURBINES	NATURAL GAS	225 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPM
LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) COMBINED CYCLE TURBINES	NATURAL GAS	650 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD
SAND HILL ENERGY CENTER	TX	9/13/2013	NATURAL GAS-FIRED COMBINED CYCLE TURBINES	NATURAL GAS	173.9 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPM
TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) COMBINED CYCLE TURBINES	NATURAL GAS	274 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPMVD
EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	COMBINED CYCLE TURBINES (>25 MW) Â€“ NATURAL GAS	NATURAL GAS	210 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPM
LON C. HILL POWER STATION	TX	10/2/2015	COMBINED CYCLE TURBINES (>25 MW)	NATURAL GAS	195 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPM
FGE EAGLE PINES PROJECT	TX	11/4/2015	COMBINED CYCLE TURBINES (>25 MW)	NATURAL GAS	321 MW	CARBON MONOXIDE	OXIDATION CATALYST	2 PPM
VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #2 (, WITH DUCT BURNING)	NATURAL GAS	154 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	3 PPMVD
VICTORVILLE 2 HYBRID POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE #1 (, WITH DUCT BURNING)	NATURAL GAS	154 MW	CARBON MONOXIDE	OXIDATION CATALYST	3 PPMVD
COLUSA GENERATING	CA	3/11/2011	COMBUSTION TURBINES	NATURAL GAS	172 MW	CARBON MONOXIDE	CATALYTIC OXIDATION	3 PPMVD

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
STATION							SYSTEM	
ROCKY MOUNTAIN ENERGY CENTER, LLC	CO	5/2/2006	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	NATURAL GAS	300 MW	CARBON MONOXIDE	USE GOOD COMBUSTION CONTROL PRACTICES AND CATALISTIC OXIDATION.	3 PPM @ 15% O2
NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B)	NATURAL GAS	7146 MMBTU/H	CARBON MONOXIDE	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	3 PPMVD @ 15% O2
FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	TURBINE, COMBINED CYCLE UNIT (SIEMENS 5000)	NATURAL GAS	2267 MMBTU/H	CARBON MONOXIDE	CO CATALYST	3 PPMVD
TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	MITSUBISHI M501-GAC COMBUSTION TURBINE, COMBINED CYCLE CONFIGURATION WITH DUCT BURNER.	NATURAL GS	2988 MMBTU/H	CARBON MONOXIDE	OXIDATION CATALYST;	3.3 PPMDV AT 15% O2
BLYTHE ENERGY PROJECT II	CA	4/25/2007	2 COMBUSTION TURBINES	NATURAL GAS	170 MW	CARBON MONOXIDE		4 PPMVD
ELK HILLS POWER LLC	CA	1/12/2006	COMBUSTION TURBINE GENERATOR, 2 UNITS	NATURAL GAS	166 MW	CARBON MONOXIDE	SCR OR SCONOX	4 PPMVD
HIGH DESERT POWER PROJECT	CA	3/11/2010	COMBUSTION TURBINE GENERATORS	NATURAL GAS	190 MW	CARBON MONOXIDE	OXIDATION CATALYST SYSTEM	4 PPMVD
PUEBLO AIRPORT GENERATING STATION	CO	7/22/2010	FOUR COMBINED CYCLE COMBUTION TURBINES	NATURAL GAS	373 MMBTU/H	CARBON MONOXIDE	GOOD COMBUSTION CONTROL AND CATALYTIC OXIDATION	4 PPMVD AT 15% O2

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
THETFORD GENERATING STATION	MI	7/25/2013	FGCCA OR FGCCB--4 NAT. GAS FIRED CTG W/ DB FOR HRSG	NATURAL GAS	2587 MMBTU/H HEAT INPUT, EACH CTG	CARBON MONOXIDE	EFFICIENT COMBUSTION CONTROL PLUS CATALYTIC OXIDATION SYSTEM.	4 PPMV
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 COMBINED CYCLE CTGS WITH HRSGS WITH DUCT BURNERS	NATURAL GAS	647 MMBTU/H FOR EACH CTGHRSG	CARBON MONOXIDE	OXIDATION CATALYST TECHNOLOGY AND GOOD COMBUSTION PRACTICES.	4 PPM
THOMAS C. FERGUSON POWER PLANT	TX	9/1/2011	NATURAL GAS-FIRED TURBINES	NATURAL GAS	390 MW	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST	4 PPMVD
CHANNEL ENERGY CENTER LLC	TX	10/15/2012	COMBINED CYCLE TURBINE	NATURAL GAS	180 MW	CARBON MONOXIDE	GOOD COMBUSTION	4 PPMVD
DEER PARK ENERGY CENTER	TX	9/26/2012	COMBINED CYCLE TURBINE	NATURAL GAS	180 MW	CARBON MONOXIDE	GOOD COMBUSTION	4 PPMVD
ES JOSLIN POWER PLANT	TX	9/12/2012	COMBINED CYCLE GAS TURBINE	NATURAL GAS	195 MW	CARBON MONOXIDE	GOOD COMBUSTION	4 PPMVD
FREEPORT LNG PRETREATMENT FACILITY	TX	7/16/2014	COMBUSTION TURBINE	NATURAL GAS	87 MW	CARBON MONOXIDE	OXIDATION CATALYST	4 PPMVD
VICTORIA POWER STATION	TX	12/1/2014	COMBINED CYCLE TURBINE	NATURAL GAS	197 MW	CARBON MONOXIDE	OXIDATION CATALYST	4 PPMVD
TRINIDAD GENERATING FACILITY	TX	11/20/2014	COMBINED CYCLE TURBINE	NATURAL GAS	497 MW	CARBON MONOXIDE	OXIDATION CATALYST	4 PPMVD
S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) COMBINED CYCLE TURBINES	NATURAL GAS	240 MW	CARBON MONOXIDE	OXIDATION CATALYST	4 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
COLORADO BEND ENERGY CENTER	TX	4/1/2015	COMBINED-CYCLE GAS TURBINE ELECTRIC GENERATING FACILITY	NATURAL GAS	1100 MW	CARBON MONOXIDE	SCR AND OXIDATION CATALYST	4 PPMVD @ 15% O2
NECHES STATION	TX	3/24/2016	COMBINED CYCLE COGENERATION	NATURAL GAS	231 MW	CARBON MONOXIDE	OXIDATION CATALYST	4 PPM
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	COMBINED CYCLE COGENERATION	NATURAL GAS	231 MW	CARBON MONOXIDE	OXIDATION CATALYST	4 PPM
CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	COMBINED CYCLE TURBINE (EP01)	NATURAL GAS	40 MW	CARBON MONOXIDE	OXIDATION CATALYST	4 PPMV AT 15% O2
CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	COMBINED CYCLE TURBINE (EP02)	NATURAL GAS	40 MW	CARBON MONOXIDE	OXIDATION CATALYST	4 PPMV AT 15% O2
OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	COMBINED-CYCLE ELECTRIC GENERATING UNIT	NATURAL GAS	3096 MMBTU/HR PER TURBINE	CARBON MONOXIDE	CLEAN BURNERS THAT PREVENT CO FORMATION	4.3 PPMVD@15% O2
NELSON ENERGY CENTER	IL	12/28/2010	ELECTRIC GENERATION FACILITY	NATURAL GAS	220 MW EACH	CARBON MONOXIDE		5 PPMVD @ 15% O2
FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	7/30/2008	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	NATURAL GAS	THREE NOMINAL 250 MW CTG (EACH)	CARBON MONOXIDE	GOOD COMBUSTION	6 PPMVD (GAS)
CANE ISLAND POWER PARK	FL	9/8/2008	COMBINED CYCLE COMBUSTION TURBINE	NATURAL GAS	300 MW	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES	6 PPMVD
PROGRESS BARTOW POWER PLANT	FL	1/26/2007	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	NATURAL GAS	1972 MMBTU/H	CARBON MONOXIDE	GOOD COMBUSTION	8 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	NATURAL GAS	2333 MMBTU/H	CARBON MONOXIDE		8 PPMVD @15%O2
CHOUTEAU POWER PLANT	OK	1/23/2009	COMBINED CYCLE COGENERATION	NATURAL GAS	25 MW	CARBON MONOXIDE	GOOD COMBUSTION	8 PPMV
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG	NATURAL GAS	2237 MMBTU/H	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES	9 PPM
FAIRBAULT ENERGY PARK	MN	6/5/2007	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	NATURAL GAS	1758 MMBTU/H	CARBON MONOXIDE	GOOD COMBUSTION	9 PPMVD
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	SIMPLE CYCLE ELECTRICAL GENERATION GAS TURBINES 15.210	NATURAL GAS	34 MW	CARBON MONOXIDE	OXIDATION CATALYST	9 PPM
NORTHERN STATES POWER CO. DBA XCEL ENERGY - RIVERSIDE PLANT	MN	5/16/2006	TURBINE, COMBINED CYCLE (2)	NATURAL GAS	1885 MMBTU/H	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES	10 PPMVD @ 15% O2
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG AND DUCT BURNER (DB)	NATURAL GAS	2486 MMBTU/H	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES	10.5 PPM
NATURAL GAS-FIRED POWER GENERATION FACILITY	TX	6/22/2009	ELECTRICITY GENERATION	NATURAL GAS	250 MW	CARBON MONOXIDE	GOOD COMBUSTION PRATICES	15 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	CO Emission Limit
BAYPORT COMPLEX	TX	9/5/2013	(4) COGENERATION TURBINES	NATURAL GAS	90 MW	CARBON MONOXIDE	DLN AND CLOSED LOOP EMISSIONS CONTROLS (CLEC)	15 PPMVD
CEDAR BAYOU ELECTRIC GENERATING STATION	TX	3/31/2015	COMBINED CYCLE TURBINES	NATURAL GAS	187 MW/TURBINE	CARBON MONOXIDE	OXIDATION CATALYSTS	15 PPMVD
LAWTON ENERGY COGEN FACILITY	OK	12/12/2006	COMBUSTION TURBINE AND DUCT BURNER			CARBON MONOXIDE	GOOD COMBUSTION PRACTICES	16.38 PPMVD
MADISON BELL ENERGY CENTER	TX	8/18/2009	ELECTRICITY GENERATION	NATURAL GAS	275 MW	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES	17.5 PPMVD
PSO SOUTHWESTERN POWER PLT	OK	2/9/2007	GAS-FIRED TURBINES			CARBON MONOXIDE	COMBUSTION CONTROL	25 PPMVD
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	REFRIGERATION COMPRESSION TURBINES	NATURAL GAS	10 M TONNES/YR	CARBON MONOXIDE	DLN BURNERS AND GOOD COMBUSTION PRACTICES	25 PPM
CORPUS CHRISTI LIQUEFACTION PLANT	TX	9/12/2014	REFRIGERATION COMPRESSOR TURBINES	NATURAL GAS	40000 HP	CARBON MONOXIDE	DRY LOW EMISSION COMBUSTORS	29 PPMVD
WEST PLANT AND EAST PLANT CENTRAL HEAT AND POWER	TX	10/13/2014	TWO COMBUSTION TURBINE-GENERATORS	NATURAL GAS	13 MW	CARBON MONOXIDE	GOOD COMBUSTION PRACTICES	50 PPM

VOC RBLC Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER	NATURAL GAS	20282 MMCF/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYSTS AND USE OF NATURAL GAS A CLEAN BURNING FUEL	0.7 PPMVD215%O2
BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	NATURAL GAS	3442 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST; GOOD COMBUSTION PRACTICES.	0.7 PPMVD
CPV TOWANTIC, LLC	CT	11/30/2015	COMBINED CYCLE POWER PLANT	NATURAL GAS	21200000 MMBTU/12 MONTHS	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	1 PPMVD @15% O2
CPV TOWANTIC, LLC	CT	11/30/2015	COMBINED CYCLE POWER PLANT	NATURAL GAS	21200000 MMBTU/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	1 PPMVD @15% O2
OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	COMBINED-CYCLE ELECTRIC GENERATING UNIT	NATURAL GAS	3096 MMBTU/HR PER TURBINE	VOLATILE ORGANIC COMPOUNDS (VOC)	COMPLETE COMBUSTION MINIMIZES VOC	1 PPMVD@15%O2
MARSHALLTOWN GENERATING STATION	IA	4/14/2014	COMBUSTION TURBINE #1 - COMBINED CYCLE	NATURAL GAS	2258 MMBTU/HR	VOLATILE ORGANIC COMPOUNDS (VOC)	CATALYTIC OXIDIZER	1 PPM
MARSHALLTOWN GENERATING STATION	IA	4/14/2014	COMBUSTION TURBINE #2 - COMBINED CYCLE	NATURAL GAS	2258 MMBTU/HR	VOLATILE ORGANIC COMPOUNDS (VOC)		1 PPM
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	NATURAL GAS	2300 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDIZED CATALYST	1 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	2449 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	1 PPMVD@15% O2
CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	725 MEGAWATT	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1 PPMVD @ 15% O2
MATTAWOMAN ENERGY CENTER	MD	11/13/2015	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	286 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1 PPMVD @ 15% O2
KEYS ENERGY CENTER	MD	10/31/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	235 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1 PPMVD @ 15% O2
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE -SIEMENS TURBINE WITHOUT DUCT BURNER	NATURAL GAS	33691 MMCF/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION PRACTICES AND USE OF NATURAL GAS AS A CLEAN BURNING FUEL	1 PPMVD@ 15%O2
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITHOUT DUCT BURNER - GENERAL ELECTRIC	NATURAL GAS	33691 MMCF/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST AND USE OF NATURAL GAS A CLEAN BURNING FUEL	1 PPMVD@15%O2
WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	20282 MMCF/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST AND USE OF NATURAL GAS A CLEAN BURNING FUEL	1 PPMVD@15%O2

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	COMBINED-CYCLE TURBINES (2) - NATURAL GAS FIRED	NATURAL GAS	3277 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	1 PPMVD
MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	COMBINED CYCLE POWER BLOCKS	NATURAL GAS	472 MW (2)	VOLATILE ORGANIC COMPOUNDS (VOC)	CO CATALYST	1 PPMDV
SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	COMBINED CYCLE COMBUSTION TURBINE AND DUCT BURNER (3)	NATURAL GAS	2538000 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	1 PPM
S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	(2) COMBINED CYCLE TURBINES	NATURAL GAS	240 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	1 PPMVD
PROGRESS BARTOW POWER PLANT	FL	1/26/2007	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	NATURAL GAS	1972 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION	1.2 PPMVD
FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	7/30/2008	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	NATURAL GAS	THREE NOMINAL 250 MW CTG (EACH)	VOLATILE ORGANIC COMPOUNDS (VOC)		1.2 PPMVD
POLK POWER STATION	FL	10/14/2012	COMBINE CYCLE POWER BLOCK (4 ON 1)	NATURAL GAS	1160 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	FUEL SULFUR LIMITS	1.4 PPMVD @15% O2
NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B)	NATURAL GAS	7146 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION PRACTICES	1.4 PPMVD @ 15% O2

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	NATURAL GAS	2333 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)		1.5 PPMVD @ 15 % O2
FAIRBAULT ENERGY PARK	MN	6/5/2007	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	NATURAL GAS	1758 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)		1.5 PPMVD
HICKORY RUN ENERGY STATION	PA	4/23/2013	COMBINED CYCLE UNITS #1 AND #2	NATURAL GAS	3.4 MMCF/HR	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	1.5 PPMVD @ 15% OXYGEN
WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	NATURAL GAS	1000 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND OXIDATION CATALYST	1.6 PPMVD @ 15% O2
PLANT MCDONOUGH COMBINED CYCLE	GA	1/7/2008	COMBINED CYCLE COMBUSTION TURBINE	NATURAL GAS	254 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	1.8 PPM @ 15% O2
KING POWER STATION	TX	8/5/2010	TURBINE	NATURAL GAS	1350 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	DLN BURNERS OXIDATION CATALYST	1.8 PPMVD AT 15% O2
WEST DEPTFORD ENERGY	NJ	5/6/2009	TURBINE, COMBINED CYCLE	NATURAL GAS	17298 MMFT3/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	CO OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1.9 PPMVD@15%O2
OTAY MESA ENERGY CENTER LLC	CA	7/22/2009	GAS TURBINE COMBINED CYCLE	NATURAL GAS	171.7 MW	VOLATILE ORGANIC COMPOUNDS (VOC)		2 PPMVD@15% OXYGEN

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
APPLIED ENERGY LLC	CA	3/20/2009	GAS TURBINE COMBINED CYCLE	NATURAL GAS	0	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPM
COLUSA GENERATING STATION	CA	3/11/2011	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	172 MW	VOLATILE ORGANIC COMPOUNDS (VOC)		2 PPMVD
LIVE OAKS POWER PLANT	GA	4/8/2010	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	NATURAL GAS	600 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION PRACTICES, CATALYTIC OXIDATION	2 PPM@15%02
LANGLEY GULCH POWER PLANT	ID	6/25/2010	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	NATURAL GAS (ONLY)	2375.28 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	CATALYTIC OXIDATION (CATOX), DLN, GOOD COMBUSTION PRACTICES	2 PPMVD
CPV ST. CHARLES	MD	4/23/2014	2 COMBINED CYCLE COMBUSTION TURBINES, WITH DUCT FIRING	NATURAL GAS	725 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	EXCLUSIVE USE OF NATURAL GAS, AND AN OXIDATION CATALYST	2 PPMVD @ 15% O2
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - SIEMENS	NATURAL GAS	33691 MMCF/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST, USE OF NATURAL GAS A CLEAN BURNING FUEL	2 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER - GENERAL ELECTRIC	NATURAL GAS	33691 MMCF/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	CO OXIDATION CATALYST, GOOD COMBUSTION PRACTICES, NATURAL GAS AS A CLEAN BURNING FUEL	2 PPMVD@15%O2
TROUTDALE ENERGY CENTER, LLC	OR	3/5/2014	MITSUBISHI M501-GAC COMBUSTION TURBINE, COMBINED CYCLE CONFIGURATION WITH DUCT BURNER.	NATURAL GS	2988 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST; LIMIT THE TIME IN STARTUP OR SHUTDOWN.	2 PPMDV AT 15% O2
FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	PA	3/4/2014	TURBINE, COMBINED CYCLE UNIT (SIEMENS 5000)	NATURAL GAS	2267 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	CO CATALYST	2 PPMVD
PATTILLO BRANCH POWER PLANT	TX	6/17/2009	ELECTRICITY GENERATION	NATURAL GAS	350 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPMVD
THOMAS C. FERGUSON POWER PLANT	TX	9/1/2011	NATURAL GAS-FIRED TURBINES	NATURAL GAS	390 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	NATURAL GAS, GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST	2 PPMVD
CHANNEL ENERGY CENTER LLC	TX	10/15/2012	COMBINED CYCLE TURBINE	NATURAL GAS	180 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION	2 PPMVD
DEER PARK ENERGY CENTER	TX	9/26/2012	COMBINED CYCLE TURBINE	NATURAL GAS	180 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION, USE OF NATURAL GAS	2 PPMVD

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
ES JOSLIN POWER PLANT	TX	9/12/2012	COMBINED CYCLE GAS TURBINE	NATURAL GAS	195 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION AND NATURAL GAS AS FUEL	2 PPMVD
PINECREST ENERGY CENTER	TX	11/12/2013	COMBINED CYCLE TURBINE	NATURAL GAS	700 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPMVD
FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	ALSTOM TURBINE	NATURAL GAS	230.7 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST, GOOD COMBUSTION PRACTICES	2 PPMVD
FREEPORT LNG PRETREATMENT FACILITY	TX	7/16/2014	COMBUSTION TURBINE	NATURAL GAS	87 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPMVD
LA PALOMA ENERGY CENTER	TX	2/7/2013	(2) COMBINED CYCLE TURBINES	NATURAL GAS	650 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPMVD
SAND HILL ENERGY CENTER	TX	9/13/2013	NATURAL GAS-FIRED COMBINED CYCLE TURBINES	NATURAL GAS	173.9 MW	VOLATILE ORGANIC COMPOUNDS (VOC)		2 PPM
TENASKA BROWNSVILLE GENERATING STATION	TX	4/29/2014	(2) COMBINED CYCLE TURBINES	NATURAL GAS	274 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPMVD
EAGLE MOUNTAIN STEAM ELECTRIC STATION	TX	6/18/2015	COMBINED CYCLE TURBINES (>25 MW) Â€“ NATURAL GAS	NATURAL GAS	210 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPM
LON C. HILL POWER STATION	TX	10/2/2015	COMBINED CYCLE TURBINES (>25 MW)	NATURAL GAS	195 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPM

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
FGE EAGLE PINES PROJECT	TX	11/4/2015	COMBINED CYCLE TURBINES (>25 MW)	NATURAL GAS	321 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPM
NECHES STATION	TX	3/24/2016	COMBINED CYCLE & COGENERATION	NATURAL GAS	231 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPM
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	COMBINED CYCLE & COGENERATION	NATURAL GAS	231 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPM
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	REFRIGERATION COMPRESSION TURBINES	NATURAL GAS	10 M TONNES/YR	VOLATILE ORGANIC COMPOUNDS (VOC)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	2 PPM
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	SIMPLE CYCLE ELECTRICAL GENERATION GAS TURBINES 15.210	NATURAL GAS	34 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	2 PPM
MADISON BELL ENERGY CENTER	TX	8/18/2009	ELECTRICITY GENERATION	NATURAL GAS	275 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION PRACTICES	2.5 PPMVD
CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	COMBINED CYCLE TURBINE (EP01)	NATURAL GAS	40 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	3 PPMV AT 15% O2
CHEYENNE PRAIRIE GENERATING STATION	WY	8/28/2012	COMBINED CYCLE TURBINE (EP02)	NATURAL GAS	40 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	3 PPMV AT 15% O2
NELSON ENERGY CENTER	IL	12/28/2010	ELECTRIC GENERATION FACILITY	NATURAL GAS	220 MW EACH	VOLATILE ORGANIC COMPOUNDS (VOC)		4 PPMVD @ 15% O2

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	VOC Emission Limit
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 COMBINED CYCLE CTGS WITH HRSGS WITH DUCT BURNERS	NATURAL GAS	647 MMBTU/H FOR EACH CTGHRSG	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST TECHNOLOGY AND GOOD COMBUSTION PRACTICES.	4 PPM
ATHENS GENERATING PLANT	NY	1/19/2007	FUEL COMBUSTION (GAS)	NATURAL GAS	3100 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION CONTROL	4 PPMVD @ 15% O2
NATURAL GAS-FIRED POWER GENERATION FACILITY	TX	6/22/2009	ELECTRICITY GENERATION	NATURAL GAS	250 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION PRACTICES	4 PPMVD
VICTORIA POWER STATION	TX	12/1/2014	COMBINED CYCLE TURBINE	NATURAL GAS	197 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	4 PPMVD
TRINIDAD GENERATING FACILITY	TX	11/20/2014	COMBINED CYCLE TURBINE	NATURAL GAS	497 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST	4 PPMVD
COLORADO BEND ENERGY CENTER	TX	4/1/2015	COMBINED-CYCLE GAS TURBINE ELECTRIC GENERATING FACILITY	NATURAL GAS	1100 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	SCR AND OXIDATION CATALYST	4 PPMVD @ 15% O2
NORTHERN STATES POWER CO. DBA XCEL ENERGY - RIVERSIDE PLANT	MN	5/16/2006	TURBINE, COMBINED CYCLE (2)	NATURAL GAS	1885 MMBTU/H	VOLATILE ORGANIC COMPOUNDS (VOC)	GOOD COMBUSTION PRACTICES	4.6 PPMVD 15% O2
MOORELAND GENERATING STA	OK	7/2/2013	COMBUSTION TURBINE	NATURAL GAS	360 MW	VOLATILE ORGANIC COMPOUNDS (VOC)	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES.	5 PPMVD@15%O2

SO_2 RBLC Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	SO_2 Emission Limit
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	NATURAL GAS	2300 MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATION	0.75 GR S/100 SCF FUEL
FGE TEXAS POWER I AND FGE TEXAS POWER II	TX	3/24/2014	ALSTOM TURBINE	NATURAL GAS	230.7 MW	SULFUR DIOXIDE (SO2)	LOW SULFUR FUEL, GOOD COMBUSTION PRACTICES	1 GR S / 100 DSCF
NECHES STATION	TX	3/24/2016	COMBINED CYCLE & COGENERATION	NATURAL GAS	231 MW	SULFUR DIOXIDE (SO2)	GOOD COMBUSTION PRACTICES, LOW SULFUR FUEL	1 GR/100 SCF
PROGRESS BARTOW POWER PLANT	FL	1/26/2007	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	NATURAL GAS	1972 MMBTU/H	SULFUR DIOXIDE (SO2)		2 GR/100SCF
FPL WEST COUNTY ENERGY CENTER	FL	1/10/2007	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	NATURAL GAS	2333 MMBTU/H	SULFUR DIOXIDE (SO2)	LOW SULFUR FUELS	2 GS/100 SCF GAS
CANE ISLAND POWER PARK	FL	9/8/2008	300 MW COMBINED CYCLE COMBUSTION TURBINE	NATURAL GAS	1860 MMBTU/H	SULFUR DIOXIDE (SO2)	FUEL SPECIFICATIONS.	2 GR S/100 SCF GAS
POLK POWER STATION	FL	10/14/2012	COMBINE CYCLE POWER BLOCK (4 ON 1)	NATURAL GAS	1160 MW	SULFUR DIOXIDE (SO2)		2 GR S/100 SCF GAS
OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	COMBINED-CYCLE ELECTRIC GENERATING UNIT	NATURAL GAS	3096 MMBTU/HR PER TURBINE	SULFUR DIOXIDE (SO2)	USE OF LOW-SULFUR FUELS	2 GR. S/100 SCF GAS

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	SO_2 Emission Limit
COLORADO BEND ENERGY CENTER	TX	4/1/2015	COMBINED-CYCLE GAS TURBINE ELECTRIC GENERATING FACILITY	NATURAL GAS	1100 MW	SULFUR DIOXIDE (SO2)	EFFICIENT COMBUSTION, NATURAL GAS FUEL	2 GR/100 SCF
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	COMBINED CYCLE & COGENERATION	NATURAL GAS	231 MW	SULFUR DIOXIDE (SO2)	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL	5 GR/100 SCF
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	REFRIGERATION COMPRESSION TURBINES	NATURAL GAS	10 M TONNES/YR	SULFUR DIOXIDE (SO2)	DRY LOW NOX BURNERS, GOOD COMBUSTION PRACTICES, PIPELINE QUALITY SWEET NATURAL GAS FUEL (LOW SULFUR FUEL)	5 GR/100 SCF

Particulate Matter (PM) RBLC Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	PM Emission Limit
THETFORD GENERATING STATION	MI	7/25/2013	FGCCA OR FGCCB--4 NAT. GAS FIRED CTG W/ DB FOR HRSG	NATURAL GAS	2587 MMBTU/H HEAT INPUT, EACH CTG	PARTICULATE MATTER, FILTERABLE (FPM)	COMBUSTION AIR FILTERS; EFFICIENT COMBUSTION CONTROL; LOW SULFUR NATURAL GAS FUEL.	0.0033 LB/MMBTU
BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	NATURAL GAS	3442 MMBTU/H	PARTICULATE MATTER, TOTAL 10 (TPM10)	LOW SULFUR/CARBON FUEL AND GOOD COMBUSTION PRACTICES.	0.0033 LB/MMBTU
BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	NATURAL GAS	3442 MMBTU/H	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	LOW SULFUR/CARBON FUEL AND GOOD COMBUSTION PRACTICES.	0.0033 LB/MMBTU
CHOUTEAU POWER PLANT	OK	1/23/2009	COMBINED CYCLE COGENERATION	NATURAL GAS	25 MW	PARTICULATE MATTER, TOTAL 10 (TPM10)	NATURAL GAS FUEL	0.0035 LB/MMBTU
MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	COMBINED CYCLE TURBINE/DUCT BURNER	NATURAL GAS	2419.61 MMBTU/HR	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	GOOD COMBUSTION PRACTICES, INLET AIR FILTRATION, & USE OF NATURAL GAS	0.0037 LB/MMBTU
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG AND DUCT BURNER (DB)	NATURAL GAS	2486 MMBTU/H	PARTICULATE MATTER, TOTAL (TPM)	GOOD COMBUSTION PRACTICES	0.004 LB/MMBTU

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	PM Emission Limit
MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	10/10/2012	COMBINED-CYCLE TURBINES (2) - NATURAL GAS FIRED	NATURAL GAS	3277 MMBTU/H	PARTICULATE MATTER, TOTAL (TPM)	USING FUEL WITH LITTLE OR NO ASH AND SULFUR CONTENT.	0.004 LB/MMBTU
WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	20282 MMCF/YR	PARTICULATE MATTER, FILTERABLE (FPM)	USE OF NATURAL GAS A CLEAN BURNING FUEL	0.0048 LB/MMBTU
PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	154 MW	PARTICULATE MATTER, TOTAL 10 (TPM10)	USE PUC QUALITY NATURAL GAS	0.0048 LB/MMBTU
PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	154 MW	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	USE PUC QUALITY NATURAL GAS	0.0048 LB/MMBTU
PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	154 MW	PARTICULATE MATTER, TOTAL (TPM)	USE PUC QUALITY NATURAL GAS	0.0048 LB/MMBTU
JOHNSONVILLE COGENERATION	TN	4/19/2016	NATURAL GAS-FIRED COMBUSTION TURBINE WITH HRSG	NATURAL GAS	1339 MMBTU/HR	PARTICULATE MATTER, TOTAL (TPM)	GOOD COMBUSTION DESIGN AND PRACTICES	0.005 LB/MMBTU
CAITHNES BELLPORT ENERGY CENTER	NY	5/10/2006	COMBUSTION TURBINE	NATURAL GAS	2221 MMBUT/H	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	LOW SULFUR FUEL	0.0055 LB/MMBTU
MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	COMBINED CYCLE POWER BLOCKS	NATURAL GAS	472 MW - (2)	PARTICULATE MATTER, TOTAL 10 (TPM10)		0.0057 LB/MMBTU
MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	COMBINED CYCLE POWER BLOCKS	NATURAL GAS	472 MW - (2)	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		0.0057 LB/MMBTU

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	PM Emission Limit
MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	COMBINED CYCLE POWER BLOCKS	NATURAL GAS	472 MW - (2)	PARTICULATE MATTER, TOTAL (TPM)		0.0057 LB/MMBTU
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG	NATURAL GAS	2237 MMBTU/H	PARTICULATE MATTER, TOTAL 10 (TPM10)	GOOD COMBUSTION PRACTICES	0.006 LB/MMBTU
NELSON ENERGY CENTER	IL	12/28/2010	ELECTRIC GENERATION FACILITY	NATURAL GAS	220 MW EACH	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		0.006 LB/MMBTU
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG	NATURAL GAS	2237 MMBTU/H	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	GOOD COMBUSTION PRACTICES	0.006 LB/MMBTU
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG	NATURAL GAS	2237 MMBTU/H	PARTICULATE MATTER, TOTAL (TPM)	GOOD COMBUSTION PRACTICES	0.006 LB/MMBTU
SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	2449 MMBTU/H	PARTICULATE MATTER, TOTAL 10 (TPM10)		0.0062 LB/MMBTU
SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	2449 MMBTU/H	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		0.0062 LB/MMBTU

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	PM Emission Limit
INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	FUEL COMBUSTION	NATURAL GAS	59900 HP	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	USE GOOD COMBUSTION PRACTICES - INCREASING THE RESIDENCE TIME AND EXCESS OXYGEN TO ENSURE COMPLETE COMBUSTION	0.0066 LB/MMBTU
INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	GE LM6000PF-25 TURBINES (4)	NATURAL GAS	59900 HP ISO	PARTICULATE MATTER, TOTAL 10 (TPM10)	GOOD COMBUSTION PRACTICES	0.0066 LB/MMBTU
SUMPTER POWER PLANT	MI	11/17/2011	COMBINED CYCLE COMBUSTION TURBINE W/ HRSG	NATURAL GAS	130 MW ELECTRICAL OUTPUT	PARTICULATE MATTER, TOTAL 10 (TPM10)		0.0066 LB/MMBTU
THETFORD GENERATING STATION	MI	7/25/2013	FGCCA OR FGCCB--4 NAT. GAS FIRED CTG W/ DB FOR HRSG	NATURAL GAS	2587 MMBTU/H HEAT INPUT, EACH CTG	PARTICULATE MATTER, TOTAL 10 (TPM10)	COMBUSTION AIR FILTERS; EFFICIENT COMBUSTION CONTROL; LOW SULFUR NATURAL GAS FUEL.	0.0066 LB/MMBTU
INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	GE LM6000PF-25 TURBINES (4)	NATURAL GAS	59900 HP ISO	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	GOOD COMBUSTION PRACTICES	0.0066 LB/MMBTU
SUMPTER POWER PLANT	MI	11/17/2011	COMBINED CYCLE COMBUSTION TURBINE W/ HRSG	NATURAL GAS	130 MW ELECTRICAL OUTPUT	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		0.0066 LB/MMBTU

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	PM Emission Limit
THETFORD GENERATING STATION	MI	7/25/2013	FGCCA OR FGCCB--4 NAT. GAS FIRED CTG W/ DB FOR HRSG	NATURAL GAS	2587 MMBTU/H HEAT INPUT, EACH CTG	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	COMBUSTION AIR FILTERS, EFFICIENT COMBUSTION CONTROL, LOW SULFUR NATURAL GAS FUEL.	0.0066 LB/MMBTU
INTERNATIONAL STATION POWER PLANT	AK	12/20/2010	GE LM6000PF-25 TURBINES (4)	NATURAL GAS	59900 HP ISO	PARTICULATE MATTER, TOTAL (TPM)	GOOD COMBUSTION PRACTICES	0.0066 LB/MMBTU
LAWTON ENERGY COGEN FACILITY	OK	12/12/2006	COMBUSTION TURBINE AND DUCT BURNER			PARTICULATE MATTER, FILTERABLE 10 (FPM10)	GOOD COMBUSTION PRACTICES	0.0067 LB/MMBTU
WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	20282 MMCF/YR	PARTICULATE MATTER, TOTAL 10 (TPM10)	USE OF NATURAL GAS A CLEAN BURNING FUEL	0.0069 LB/MMBTU
WEST DEPTFORD ENERGY STATION	NJ	7/18/2014	COMBINED CYCLE COMBUSTION TURBINE WITH DUCT BURNER	NATURAL GAS	20282 MMCF/YR	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	USE OF NATURAL GAS A CLEAN BURNING FUEL	0.0069 LB/MMBTU
CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	725 MEGAWATT	PARTICULATE MATTER, FILTERABLE (FPM)	USE OF PIPELINE-QUALITY NATURAL GAS EXCLUSIVELY AND GOOD COMBUSTION PRACTICE	0.007 LB/MMBTU
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 COMBINED CYCLE CTGS WITH HRSGS WITH DUCT BURNERS	NATURAL GAS	647 MMBTU/H FOR EACH CTGHRSG	PARTICULATE MATTER, FILTERABLE (FPM)	GOOD COMBUSTION PRACTICES AND THE USE OF PIPELINE QUALITY NATURAL GAS.	0.007 LB/MMBTU

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	PM Emission Limit
ROCKY MOUNTAIN ENERGY CENTER, LLC	CO	5/2/2006	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	NATURAL GAS	300 MW	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	NATURAL GAS QUALITY FUEL ONLY AND GOOD COMBUSTION CONTROL PRACTICES.	0.0074 LB/MMBTU
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	NATURAL GAS	2300 MMBTU/H	PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)	GOOD COMBUSTION PRACTICE AND FUEL SPECIFICATION	0.0078 LB/MMBTU
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	NATURAL GAS	2300 MMBTU/H	PARTICULATE MATTER, FILTERABLE (FPM)	GOOD CUMBUSTION PRACTICE AND FUEL SPECIFICATION	0.0078 LB/MMBTU
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG AND DUCT BURNER (DB)	NATURAL GAS	2486 MMBTU/H	PARTICULATE MATTER, TOTAL 10 (TPM10)	GOOD COMBUSTION PRACTICES	0.008 LB/MMBTU
MIDLAND COGENERATION VENTURE	MI	4/23/2013	NATURAL GAS FUELED COMBINED CYCLE COMBUSTION TURBINE GENERATORS (CTG) WITH HRSG AND DUCT BURNER (DB)	NATURAL GAS	2486 MMBTU/H	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	GOOD COMBUSTION PRACTICES	0.008 LB/MMBTU
SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	COMBINED CYCLE COMBUSTION TURBINE AND DUCT BURNER (3)	NATURAL GAS	2538000 MMBTU/H	PARTICULATE MATTER, TOTAL (TPM)		0.0088 LB/MMBTU

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Facility Name	State	Permit Date	Emissions Source	Fuel	Load	Pollutant	Control Description	PM Emission Limit
PSO SOUTHWESTERN POWER PLT	OK	2/9/2007	GAS-FIRED TURBINES			PARTICULATE MATTER, FILTERABLE 10 (FPM10)	USE OF LOW ASH FUEL (NATURAL GAS) AND EFFICIENT COMBUSTION	0.0093 LB/MMBTU
FAIRBAULT ENERGY PARK	MN	6/5/2007	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	NATURAL GAS	1758 MMBTU/H	PARTICULATE MATTER, FILTERABLE 10 (FPM10)		0.01 LB/MMBTU
MARSHALLTOWN GENERATING STATION	IA	4/14/2014	COMBUSTION TURBINE #1 - COMBINED CYCLE	NATURAL GAS	2258 MMBTU/HR	PARTICULATE MATTER, TOTAL (TPM)		0.01 LB/MMBTU
MARSHALLTOWN GENERATING STATION	IA	4/14/2014	COMBUSTION TURBINE #2 - COMBINED CYCLE	NATURAL GAS	2258 MMBTU/HR	PARTICULATE MATTER, TOTAL (TPM)		0.01 LB/MMBTU
CPV ST. CHARLES	MD	4/23/2014	2 COMBINED-CYCLE COMBUSTION TURBINES	NATURAL GAS	725 MEGAWATT	PARTICULATE MATTER, TOTAL 10 (TPM10)	PIPELINE-QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.011 LB/MMBTU
NELSON ENERGY CENTER	IL	12/28/2010	ELECTRIC GENERATION FACILITY	NATURAL GAS	220 MW EACH	PARTICULATE MATTER, TOTAL 10 (TPM10)		0.012 LB/MMBTU
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 COMBINED CYCLE CTGS WITH HRSGS WITH DUCT BURNERS	NATURAL GAS	647 MMBTU/H FOR EACH CTGHRSG	PARTICULATE MATTER, TOTAL 10 (TPM10)	PIPELINE-QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.014 LB/MMBTU
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	FG-CTGHRSG: 2 COMBINED CYCLE CTGS WITH HRSGS WITH DUCT BURNERS	NATURAL GAS	647 MMBTU/H FOR EACH CTGHRSG	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	PIPELINE-QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICE	0.014 LB/MMBTU

RACT/BACT/LAER Clearinghouse (RBLC) Data for Gas Turbines

Attachment 4

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

PARTICULATE MATTER (PM) RBLC DATA FOR COOLING TOWERS

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
GERDAU MACSTEEL, INC.	MI	01/04/2013	CASTER COOLING TOWER	1630 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATOR	0.0005
LINDALE RENEWABLE ENERGY	TX	01/08/2010	COOLING TOWER		PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATORS	0.0005 % DRIFT
DIRECT REDUCTION IRON PLANT	LA	01/27/2011	DRI-113 - DRI UNIT #1 PROCESS WATER COOLING TOWER	26,857 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	BACT IS A COMBINATION OF LESS THAN OR EQUAL TO 1,000 MILLIGRAMS PER LITER TDS CONCENTRATION IN THE COOLING WATER AND DRIFT ELIMINATORS EMPLOYING A DRIFT MAXIMUM OF 0.0005%.	0.0005
DIRECT REDUCTION IRON PLANT	LA	01/27/2011	DRI-213 - DRI UNIT #2 PROCESS WATER COOLING TOWER	26,857 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	BACT IS A COMBINATION OF LESS THAN OR EQUAL TO 1,000 MILLIGRAMS PER LITER TDS CONCENTRATION IN THE COOLING WATER AND DRIFT ELIMINATORS EMPLOYING A DRIFT MAXIMUM OF 0.0005%.	0.0005
DIRECT REDUCTION IRON PLANT	LA	01/27/2011	DRI-114 - DRI UNIT #1 CLEAN WATER COOLING TOWER	17,611 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	BACT IS A COMBINATION OF LESS THAN OR EQUAL TO 1,000 MILLIGRAMS PER LITER TDS CONCENTRATION IN THE COOLING WATER AND DRIFT ELIMINATORS EMPLOYING A DRIFT MAXIMUM OF 0.0005%.	0.0005

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
DIRECT REDUCTION IRON PLANT	LA	01/27/2011	DRI-214 - DRI UNIT #1 CLEAN WATER COOLING TOWER	17,611 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	BACT IS A COMBINATION OF LESS THAN OR EQUAL TO 1,000 MILLIGRAMS PER LITER TDS CONCENTRATION IN THE COOLING WATER AND DRIFT ELIMINATORS EMPLOYING A DRIFT MAXIMUM OF 0.0005%.	0.0005
PANDA SHERMAN POWER STATION	TX	02/03/2010	COOLING TOWER		PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATORS	0.0005 % DRIFT
POWER COUNTY ADVANCED ENERGY CENTER	ID	02/10/2009	COOLING TOWER, SRC22	121,000 GPM	PARTICULATE MATTER (PM)	DRIFT/MIST ELIMINATORS	0.0005 % OF TOTAL CIRC FLOW
POWER COUNTY ADVANCED ENERGY CENTER	ID	02/10/2009	COOLING TOWER, SRC22	121,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT/MIST ELIMINATORS	0.0005 % OF TOTAL CIRC FLOW
LEVY NUCLEAR PLANT	FL	02/20/2009	INDUSTRIAL PROCESS COOLING TOWER	600,000 GPM	PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATORS	0.0005 % DRIFT RATE
WOLF HOLLOW POWER PLANT NO. 2	TX	03/03/2010	COOLING TOWER		PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATORS	0.0005 % DRIFT
OKEECHOBEE CLEAN ENERGY CENTER	FL	03/09/2016	MECHANICAL DRAFT COOLING TOWER	465,815 GALLONS WATER/MIN	PARTICULATE MATTER, TOTAL (TPM)	MUST HAVE CERTIFIED DRIFT RATE NO MORE THAN 0.0005%.	0.0005
VICTORVILLE 2 HYBRID POWER PROJECT	CA	03/11/2010	COOLING TOWER	130000 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		0.0005 % DRIFT
VICTORVILLE 2 HYBRID POWER PROJECT	CA	03/11/2010	COOLING TOWER	130000 GPM	PARTICULATE MATTER, TOTAL (TPM)		0.0005 % DRIFT

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
DIRECT REDUCED IRON AND HOT BRIQUETTING FACILITY	TX	03/18/2014	COOLING TOWER	220,5000	PARTICULATE MATTER, TOTAL 10 (TPM10)	A COOLING TOWER WITH A DRIFT LOSS OF 0.0005%.	0.0005 DRIFT LOSS
DIRECT REDUCED IRON AND HOT BRIQUETTING FACILITY	TX	03/18/2014	COOLING TOWER	2,205,000	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	A COOLING TOWER WITH A DRIFT LOSS OF 0.0005%.	0.0005 DRIFT LOSS
DIRECT REDUCED IRON AND HOT BRIQUETTING FACILITY	TX	03/18/2014	COOLING TOWER	2,205,000	PARTICULATE MATTER, TOTAL (TPM)	A COOLING TOWER WITH A DRIFT LOSS OF 0.0005%.	0.0005 DRIFT LOSS
AGP SOY	NE	03/25/2015	COOLING TOWER	360,000 GAL/HR	PARTICULATE MATTER, TOTAL (TPM)	DRIFT LOSS DESIGN SPECIFICATION AND TDS CONCENTRATION LIMIT	0.0005 %
AMMONIA PRODUCTION FACILITY	LA	03/27/2013	COOLING TOWER (2101-U)	93,467 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS TO CONTROL DRIFT TO NO MORE THAN 0.0005%.	0.0005
AMMONIA PRODUCTION FACILITY	LA	03/27/2013	COOLING TOWER (2101-U)	93,467 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS TO CONTROL DRIFT TO NO MORE THAN 0.0005%.	0.0005
PEONY CHEMICAL MANUFACTURIN G FACILITY	TX	04/01/2015	COOLING TOWER	40,000 GALLONS PER MINUTE	PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATOR IS 0.0005% EFFICIENT	0.0005
PEONY CHEMICAL MANUFACTURIN G FACILITY	TX	04/01/2015	COOLING TOWER	40,000 GALLONS PER MINUTE	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATOR IS 0.0005% EFFICIENT	0.0005

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
PEONY CHEMICAL MANUFACTURING FACILITY	TX	04/01/2015	COOLING TOWER	40,000 GALLONS PER MINUTE	PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATOR IS 0.0005% EFFICIENT	0.0005
ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	04/10/2014	WET COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR DESIGNED TO LIMIT CIRCULATING WATER FLOW DRIFT LOSS TO 0.0005% OR LESS.	0.0005
ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	04/10/2014	WET COOLING TOWER		PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)	DRIFT ELIMINATOR DESIGNED TO LIMIT CIRCULATING WATER FLOW DRIFT LOSS TO 0.0005% OR LESS.	0.0005
ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	04/10/2014	WET COOLING TOWER		PARTICULATE MATTER, FILTERABLE (FPM)	DIRFT ELIMINATOR DESIGNED TO LIMIT CIRCULATING WATER FLOW DRIFT LOSS TO 0.0005% OR LESS.	0.0005
TENASKA BROWNSVILLE GENERATING STATION	TX	04/29/2014	COOLING TOWER		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	MIST ELIMINATORS	0.0005 %

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
NUCOR STEEL LOUISIANA	LA	05/24/2010	TWR-101 - BLAST FURNACE COOLING TOWER		PARTICULATE MATTER, FILTERABLE (FPM)	BACT IS SELECTED TO BE A COMBINATION OF LESS THAN 1,000 MILLIGRAMS PER LITER TDS CONCENTRATION IN THE COOLING WATER AND DRIFT ELIMINATORS EMPLOYING A DRIFT MAXIMUM OF 0.0005%.	0.0005
NUCOR STEEL LOUISIANA	LA	05/24/2010	TWR-102 - IRON SOLIDIFICATION COOLING TOWER		PARTICULATE MATTER, FILTERABLE (FPM)	BACT IS SELECTED TO BE A COMBINATION OF LESS THAN 1,000 MILLIGRAMS PER LITER TDS CONCENTRATION IN THE COOLING WATER AND DRIFT ELIMINATORS EMPLOYING A DRIFT MAXIMUM OF 0.0005%.	0.0005
NUCOR STEEL LOUISIANA	LA	05/24/2010	TWR-103 - AIR SEPARATION PLANT COOLING TOWER		PARTICULATE MATTER, FILTERABLE (FPM)	BACT IS SELECTED TO BE A COMBINATION OF LESS THAN 1,000 MILLIGRAMS PER LITER TDS CONCENTRATION IN THE COOLING WATER AND DRIFT ELIMINATORS EMPLOYING A DRIFT MAXIMUM OF 0.0005%.	0.0005
ENID NITROGEN PLANT	OK	05/29/2014	COOLING TOWERS		PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATORS	0.0005
ENID NITROGEN PLANT	OK	05/29/2014	COOLING TOWERS		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATORS	0.0005
FPL TURKEY POINT NUCLEAR PLANT	FL	05/30/2009	INDUSTRIAL COOLING TOWERS	210,367 GPM/TOWER	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	COOLING TOWER DESIGN PLUS HIGH EFFICIENCY DRIFT ELIMINATORS; HIGHER CONCENTRATIONS OF SOLIDS IN COOLING WATER RESULTS IN FORAMTION OF PM/PM10.	0.0005 %

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
FPL TURKEY POINT NUCLEAR PLANT	FL	05/30/2009	INDUSTRIAL COOLING TOWERS	210,367 GPM/TOWER	PARTICULATE MATTER, TOTAL (TPM)	COOLING TOWER DESIGN PLUS HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 %
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	TEN CELL EVAPORATIVE COOLING TOWER	147,937 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	SIX CELL EVAPORATIVE COOLING TOWER	88,762 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	TEN CELL EVAPORATIVE COOLING TOWER	147,937 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	SIX CELL EVAPORATIVE COOLING TOWER	88,762 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	TEN CELL EVAPORATIVE COOLING TOWER	147,937 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	SIX CELL EVAPORATIVE COOLING TOWER	88,762 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	TEN CELL EVAPORATIVE COOLING TOWER	147,937 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	SIX CELL EVAPORATIVE COOLING TOWER	88,762 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	TEN CELL EVAPORATIVE COOLING TOWER	147,937 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	SIX CELL EVAPORATIVE COOLING TOWER	88,762 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	TEN CELL EVAPORATIVE COOLING TOWER	147,937 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
MIDWEST FERTILIZER CORPORATION	IN	06/04/2014	SIX CELL EVAPORATIVE COOLING TOWER	88,762 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS
ANCHORAGE MUNICIPAL LIGHT & POWER	AK	06/06/2013	COOLING TOWER		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	INSTALL, OPERATE, AND MAINTAIN A HIGH EFFICIENCY DRIFT ELIMINATOR WITH A MAXIMUM DRIFT OF 0.0005 PERCENT OF CIRCULATING WATER.	0.0005
GRANGER FACILITY	WY	06/12/2013	COOLING TOWER		PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT RATE LIMITED TO 0.0005%	0.0005
INDIANA GASIFICATION, LLC	IN	06/27/2012	ASU COOLING TOWER	54,960 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	HIGH EFFICIENCY DRIFT ELIMINATORS DESIGNED WITH A DRIFT LOSS RATE OF LESS THAN 0.0005%	0.0005
INDIANA GASIFICATION, LLC	IN	06/27/2012	ASU COOLING TOWER	54,960 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS DESIGNED WITH A DRIFT LOSS RATE OF LESS THAN 0.0005%	0.0005

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
INDIANA GASIFICATION, LLC	IN	06/27/2012	ASU COOLING TOWER	54,960 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS DESIGNED WITH A DRIFT LOSS RATE OF LESS THAN 0.0005%	0.0005
ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007	INDUSTRIAL COOLING TOWER	150,000 GPM	PARTICULATE MATTER (PM)	DRIFT ELIMINATORS	0.0005 %
ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007	INDUSTRIAL COOLING TOWER	150,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATORS	0.0005 % EFF. DRIFT ELIMIN
WOLVERINE POWER	MI	06/29/2011	COOLING TOWER (EUCOOLINGTWR)		PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATORS	0.0005 %
MOORELAND GENERATING STA	OK	07/02/2013	COOLING TOWER (GE OPTION)		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	MAKEUP WATER CONTROLS AND 0.0005% DRIFT ELIMINATORS.	0.0005
MOORELAND GENERATING STA	OK	07/02/2013	COOLING TOWER (SIEMENS OPTION)		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	MAKEUP WATER CONTROLS AND 0.0005% DRIFT ELIMINATORS.	0.0005
CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	07/12/2013	COOLING TOWERS		PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATOR	0.0005 %
CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	07/12/2013	COOLING TOWERS		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATOR	0.0005 %

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	07/12/2013	COOLING TOWERS		PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATOR	0.0005 %
SPECIALTY MINERALS INC. - SUPERIOR	WI	07/22/2011	P30 - DIRECT CONTACT SCRUBBER WITH COOLING TOWER	515 GPM	PARTICULATE MATTER (PM)	HIGH EFFICIENCY MIST / DRIFT ELIMINATOR (WITH ADDITIONAL LAYER), LIMITS ON % SOLIDS	0.0005
SPECIALTY MINERALS INC. - SUPERIOR	WI	07/22/2011	P40, P50 - COOLING TOWERS	700 GPM	PARTICULATE MATTER (PM)	HIGH EFFICIENCY MIST / DRIFT ELIMINATORS (W/ ADDITIONAL LAYER)	0.0005
SPECIALTY MINERALS INC. - SUPERIOR	WI	07/22/2011	P60 - COOLING TOWER	200 GPM	PARTICULATE MATTER (PM)	HIGH EFFICIENCY MIST / DRIFT ELIMINATORS (W/ ADDITIONAL LAYER); DISSOLVED SOLIDS LIMIT	0.0005
SPECIALTY MINERALS INC. - SUPERIOR	WI	07/22/2011	P30 - DIRECT CONTACT SCRUBBER WITH COOLING TOWER	515 GPM	PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATOR (W/ ADDITIONAL LAYER)	0.0005
SPECIALTY MINERALS INC. - SUPERIOR	WI	07/22/2011	P40, P50 - COOLING TOWERS	700 GPM	PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)	HIGH EFFICIENCY MIST / DRIFT ELIMINATOR (W/ ADDITONAL LAYER)	0.0005
SPECIALTY MINERALS INC. - SUPERIOR	WI	07/22/2011	P60 - COOLING TOWER	200 GPM	PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)	HIGH EFFICIENCY MIST / DRIFT ELIMINATORS (W/ ADDITIONAL LAYER); DISSOLVED SOLIDS LIMIT	0.0005
BERLIN BIOPOWER	NH	07/26/2010	EU02 4-CELL WET COOLING TOWER	60,000 GPM	PARTICULATE MATTER, FUGITIVE	DRIFT ELIMINATORS	0.0005

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	07/30/2008	ONE 26-CELL MECHANICAL DRAFT COOLING TOWER		PARTICULATE MATTER (PM)	THE PERMITTEE SHALL CERTIFY THAT THE COOLING TOWER WAS CONSTRUCTED TO ACHIEVE THE SPECIFIED DRIFT RATE OF NO MORE THAN 0.0005 PERCENT OF THE CIRCULATING WATER FLOW RATE.	0.0005 %
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007	COOLING TOWER, F80 (07-A-979P)	50,000 GPM	PARTICULATE MATTER (PM)	DRIFT ELIMINATOR / DEMISTER	0.0005 % DRIFT LOSS
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007	COOLING TOWER, F80 (07-A-979P)	50,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR / DEMISTER	0.0005 % DRIFT LOSS
NINEMILE POINT ELECTRIC GENERATING PLANT	LA	08/16/2011	UNIT 6 COOLING TOWER	115,847 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY MIST ELIMINATOR	0.0005 PERCENT DRIFT
NINEMILE POINT ELECTRIC GENERATING PLANT	LA	08/16/2011	UNIT 6 COOLING TOWER	115,847 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY MIST ELIMINATOR	0.0005 PERCENT DRIFT
CRONUS CHEMICALS, LLC	IL	09/05/2014	COOLING TOWER		PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATORS; TDS OF WATER NOT TO EXCEED 2000 MG/L	0.0005
CRONUS CHEMICALS, LLC	IL	09/05/2014	COOLING TOWER		PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATORS; TDS OF WATER NOT TO EXCEED 2000 MG/L	0.0005

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
CRONUS CHEMICALS, LLC	IL	09/05/2014	COOLING TOWER		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATORS; TDS OF WATER NOT TO EXCEED 2000 MG/L	0.0005
SPIRITWOOD STATION	ND	09/14/2007	COOLING TOWER	80,000 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR	0.0005 % COOLING WATER FLOW
TATE & LYLE INDGREDIENTS AMERICAS, INC.	IA	09/19/2008	COOLING TOWER		PARTICULATE MATTER (PM)	DRIFT ELIMINATORS	0.0005 %
TATE & LYLE INDGREDIENTS AMERICAS, INC.	IA	09/19/2008	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATORS	0.0005 %
OHIO VALLEY RESOURCES, LLC	IN	09/25/2013	TWO (2) COOLING TOWERS	179,720 GPM, COMBINED	PARTICULATE MATTER, FILTERABLE (FPM)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT
OHIO VALLEY RESOURCES, LLC	IN	09/25/2013	TWO (2) COOLING TOWERS	179,720 GPM, COMBINED	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT
AVENTINE RENEWABLE ENERGY - AURORA WEST LLC	NE	09/27/2007	COOLING TOWER		PARTICULATE MATTER (PM)	MIST ELIMINATOR	0.0005
CRYSTAL RIVER POWER PLANT	FL	10/12/2007	COOLING TOWERS	342,306 GPM	PARTICULATE MATTER (PM)		0.0005 PERCENT
PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COOLING TOWER	130,000 GPM CIRCULATION RATE	PARTICULATE MATTER, TOTAL 10 (TPM10)		0.0005 % DRIFT

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COOLING TOWER	130,000 GPM CIRCULATION RATE	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		0.0005 % DRIFT
PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COOLING TOWER	130,000 GPM CIRCULATION RATE	PARTICULATE MATTER, TOTAL (TPM)		0.0005 % DRIFT
IOWA FERTILIZER COMPANY	IA	10/26/2012	COOLING TOWER		PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATOR	0.0005
IOWA FERTILIZER COMPANY	IA	10/26/2012	COOLING TOWER		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATOR	0.0005
IOWA FERTILIZER COMPANY	IA	10/26/2012	COOLING TOWER		PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATOR	0.0005
JOHN W. TURK JR. POWER PLANT	AR	11/05/2008	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATORS 0.0005% DRIFT RATE	0.0005
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012	TWO (2) COOLING TOWERS	170,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR	0.0005 % DRIFT LOSS
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012	TWO (2) COOLING TOWERS	170,000 GPM	PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)	DRIFT ELIMINATOR	0.0005 % DRIFT LOSS
ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012	TWO (2) COOLING TOWERS	170,000 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR	0.0005 % DRIFT LOSS

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
WARREN COUNTY BIOMASS ENERGY FACILITY	GA	12/17/2010	COOLING TOWER	0	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATORS	0.0005 % EFFECTIVENESS
S R BERTRON ELECTRIC GENERATING STATION	TX	12/19/2014	COOLING TOWER	0	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATORS	0.0005 %
MIDLAND POWER STATION	MI	12/21/2011	COOLING TOWER	0	PARTICULATE MATTER, FILTERABLE (FPM)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % DRIFT LOSS RATE
GAINESVILLE RENEWABLE ENERGY CENTER	FL	12/28/2010	MECHANICAL DRAFT COOLING TOWER	78,000 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	THE TOWER WILL BE EQUIPPED WITH DRIFT ELIMINATORES TO MEET A PROPOSED DRIFT RATE OF 0.0005%	0.0005
OSCEOLA STEEL CO.	GA	12/29/2010	COOLING TOWERS, CT1, CT21, CT22, AND CT23	0	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATORS	0.0005 % MASS FLOW RATE
AMERICAN ENERGY PRODUCERS, INC.	MO	01/25/2008	COOLING TOWER	0	PARTICULATE MATTER, TOTAL (TPM)	HIGH EFFICIENCY DRIFT ELIMINATORS WITH A DRIFT DESIGN TO LESS THAN 0.001 PERCENT. RECIRCULATION CANNOT EXCEED 990,000 GALLONS PER HOUR AND TDS CANNOT EXCEED 1050 PPM.	0.001
LA PALOMA ENERGY CENTER	TX	02/07/2013	COOLING TOWER	0	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	MIST ELIMINATORS	0.001 %

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
POWER COUNTY ADVANCED ENERGY CENTER	ID	02/10/2009	ZLDS COOLING TOWER, SRC30	985 GPM	PARTICULATE MATTER (PM)	DRIFT/MIST ELIMINATORS	0.001 % OF TOTAL CIRC FLOW
POWER COUNTY ADVANCED ENERGY CENTER	ID	02/10/2009	ZLDS COOLING TOWER, SRC30	985 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT/MIST ELIMINATORS	0.001 % OF TOTAL CIRC FLOW
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	03/07/2014	3 CELL WET MECHANICAL COOLING TOWER	13,000 GAL/M	PARTICULATE MATTER, FILTERABLE (FPM)		0.001
MAGNETATION LLC	IN	04/16/2013	COOLING TOWER	4600 GPM OF CIRCULATING WATER	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT EMILINATORS	0.001 % MAXIMUM DRIFT RATE
MAGNETATION LLC	IN	04/16/2013	COOLING TOWER	4600 GPM OF CIRCULATING WATER	PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATORS	0.001 % MAX DRIFT RATE
MAGNETATION LLC	IN	04/16/2013	COOLING TOWER	4600 GPM OF CIRCULATING WATER	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATORS	0.001 % MAXIMUM DRIFT RATE
EMBERCLEAR GTL MS	MS	05/08/2014	INDUCED DRAFT COOLING TOWER	1420 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.001 %
EMBERCLEAR GTL MS	MS	05/08/2014	INDUCED DRAFT COOLING TOWER	1420 GPM	PARTICULATE MATTER, TOTAL (TPM)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.001 %

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
BEAUMONT GAS TO GASOLINE PLANT	TX	05/16/2014	COOLING TOWER	99,000,000 GALLONS/YR	PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATORS (LIMIT 0.001 % DRIFT)AND MONITORING OF TDS OR CONDUCTIVITY EMISSION LIMIT FOR PM IS 82.57 TPY EMISSION LIMIT FOR PM10 IS 1.28 TPY EMISSION LIMIT FOR PM2.5 IS 0.03 TPY	0.001
GEORGIA PACIFIC BRETON LLC	AL	06/11/2014	COOLING TOWER - NO. 4 POWER BOILER	425 MMBTU/H	PARTICULATE MATTER, FUGITIVE		0.001 0.001% DRIFT ELIMINATER
LOW DENSITY POLYETHYLENE (LDPE) PLANT	TX	08/08/2014	COOLING TOWER	0	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	COOLING TOWER WILL HAVE DRIFT ELIMINATORS	0.001 %
NINEMILE POINT ELECTRIC GENERATING PLANT	LA	08/16/2011	CHILLER COOLING TOWER (CHILL CT)	12,000 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY MIST ELIMINATOR	0.001 PERCENT DRIFT
NINEMILE POINT ELECTRIC GENERATING PLANT	LA	08/16/2011	CHILLER COOLING TOWER (CHILL CT)	12,000 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY MIST ELIMINATOR	0.001 PERCENT DRIFT
GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	VA	08/27/2012	COOLING TOWER	55,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	USE OF DRIFT ELIMINATORS TO A DRIFT RATE OF 0.001% OF THE CIRCULATING WATER FLOW AND A TOTAL DISSOLVED SOLIDS CONTENT OF THE COOLING WATER OF NO MORE THAN 1200 MG/L.	0.001

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	VA	08/27/2012	COOLING TOWER	55,000 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	USE OF DRIFT ELIMINATORS TO A DRIFT RATE OF 0.001% OF THE CIRCULATING WATER FLOW AND A TOTAL DISSOLVED SOLIDS CONTENT OF THE COOLING WATER OF NO MORE THAN 1200 MG/L.	0.001
CELANESE CLEAR LAKE PLANT	TX	09/16/2013	COOLING TOWER		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATORS WITH A DRIFF FACTOR OF 0001% IS USED	0.001 PERCENT
HILLSBOROUGH COUNTY RESOURCE RECOVERY FACILITY	FL	11/03/2006	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATORS	0.001
BISHOP FACILITY	TX	11/12/2015	COOLING TOWER	10,400	PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATORS MEETING 0.001% DRIFT	0.001
BISHOP FACILITY	TX	11/12/2015	COOLING TOWER	10,400	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATORS MEETING 0.001% DRIFT	0.001
TRINIDAD GENERATING FACILITY	TX	11/20/2014	COOLING TOWER		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	MIST ELIMINATORS	0.001 %
MGM MIRAGE	NV	11/30/2009	COOLING TOWERS - UNITS CC026, CC027, AND CC028 AT CITY CENTER	10,890 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	EACH UNIT IS EQUIPPED WITH A DRIFT ELIMINATOR LIMITING THE DRIFT RATE TO 0.001% AND THE TOTAL DISSOLVED SOLIDS IN THE CURCULATION WATER IS LIMITED TO 3,600 PPM.	0.001

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
VICTORIA POWER STATION	TX	12/01/2014	COOLING TOWER		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	MIST ELIMINATORS	0.001 %
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: CASTER SPRAYS (CONTACT) ID#15F	3500 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.001 % DRIFT RATE
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: ROLLING MILL (CONTACT) ID#15A	8000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.001 % DRIFT RATE
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: ROLLING MILL (CONTACT) ID#15B	4000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS	0.001 % DRIFT RATE
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: ROLLING MILL ID#15C (NONCONTACT)	81,250 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.001 % DRIFT RATE

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: #1 CAST ID#15D (CONTACT)	5000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.001 % DRAFT RATE
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: CASTER SPRAYS (CONTACT) ID#15F	3500 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.001 % DRIFT RATE
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: ROLLING MILL (CONTACT) ID#15A	8000 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.001 % DRIFT RATE
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: ROLLING MILL (CONTACT) ID#15B	4000 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS	0.001 % DRIFT RATE
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: ROLLING MILL ID#15C (NONCONTACT)	81,250 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.001 % DRIFT RATE

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: #1 CAST ID#15D (CONTACT)	5000 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS	0.001 % DRAFT RATE
CRYSTAL RIVER POWER PLANT	FL	04/04/2006	PORTABLE COOLING TOWER	180,000 GPM	PARTICULATE MATTER (PM)	DRIFT ELIMINATORS	0.0015 % DRIFT RATE
KENAI NITROGEN OPERATIONS	AK	01/06/2015	2 CELL CROSS-FLOW COOLING TOWER	15,000 GALLONS PER MINUTE	PARTICULATE MATTER, FUGITIVE	HIGH EFFICIENCY DRIFT ELIMINATORS	0.002 % DRIFT
KENAI NITROGEN OPERATIONS	AK	01/06/2015	2 CELL CROSS-FLOW COOLING TOWER	15,000 GALLONS PER MINUTE	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.002 % DRIFT
KENAI NITROGEN OPERATIONS	AK	01/06/2015	2 CELL CROSS-FLOW COOLING TOWER	15,000 GALLONS PER MINUTE	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.002 % DRIFT
CHOCOLATE BAYOU FACILITY	TX	06/30/2009	COOLING TOWER	165,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATORS	0.002 %
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: ROLLING MILL/CASTER (NON-CONTACT) ID#15E	18,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.003 % DRIFT RATE
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: ROLLING MILL/CASTER (NON-CONTACT) ID#15E	18,000 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.003 % DRIFT RATE

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
NELLIS AIR FORCE BASE	NV	02/26/2008	COOLING TOWERS		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	LIMIT OF TOTAL DISSOLVED SOLIDS IN THE CIRCULATING WATER TO 0.03 LBS/GAL, LIMIT OF THROUGHPUT TO 1,200 GPM, AND LIMIT OF DRIFT PERCENT TO 0.005	0.005
V & M STAR	OH	04/10/2009	MELT SHOP COOLING TOWER	3,000,000 GAL/H	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR WITH 0.005% DRIFT LOSS OF CIRCULATING WATER FLOW RATE	0.005
V & M STAR	OH	04/10/2009	PIPE MILL COOLING TOWER	1,800,000 GAL/H	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR WITH A MAXIMUM DRIFT RATE OF 0.005% OF CIRCULATING WATER FLOW RATE INTO THE EMISSIONS UNIT.	0.005
V & M STAR	OH	04/10/2009	MELT SHOP COOLING TOWER	3,000,000 GAL/H	VISIBLE EMISSIONS (VE)	DRIFT ELIMINATOR WITH 0.005% DRIFT LOSS OF CIRCULATING WATER FLOW RATE	0.005
V & M STAR	OH	04/10/2009	PIPE MILL COOLING TOWER	1,800,000 GAL/H	VISIBLE EMISSIONS (VE)	DRIFT ELIMINATOR WITH A MAXIMUM DRIFT RATE OF 0.005% OF CIRCULATING WATER FLOW RATE INTO THE EMISSIONS UNIT.	0.005
SOUTHWEST IOWA RENEWABLE ENERGY	IA	04/19/2007	COOLING TOWERS	3,000,000 GAL/H	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	MIST ELIMINATOR 0.005%	0.005
PLAQUEMINE COGENERATION FACILITY	LA	07/23/2008	COOLING TOWER	0.01 % DRIFT RATE	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	GOOD OPERATING PRACTICES	0.005 % DRIFT RATE

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009	COOLING TOWER - UNIT HA19	7200 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	A DRIFT ELIMINATOR CONTROLS DRIFT RATE TO 0.005%, AND THE PERMITTEE IS REQUIRED TO MAINTAIN TSD CONTENT IN THE COOLING WATER TO A MAXIMUM OF 2,520 PPM.	0.005
HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009	COOLING TOWER - UNIT FL17	6900 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR TO REDUCE DRIFT RATE TO LESS THAN 0.005% AND MAINTAINING TOTAL DISSOLVED SOLIDS CONTENT IN THE COOLING WATER TO BELOW 3,000 PPM.	0.005
MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007	COOLING TOWER		PARTICULATE MATTER (PM)	DESIGNED TO MINIMIZE DRIFT	0.005 % DRIFT RATE
MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DESIGNED TO MINIMIZE DRIFT	0.005 % DRIFT RATE
OHIO VALLEY RESOURCES, LLC	IN	09/25/2013	TWO (2) COOLING TOWERS	179,720 GPM, COMBINED	PARTICULATE MATTER, TOTAL 10 (TPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.005 % DRIFT
DRY FORK STATION	WY	10/15/2007	COOLING TOWERS		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	MIST ELIMINATORS-0.005% DRIFT LOSS	0.005 %
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: LVD BOILER (CONTACT) ID#15G	2500 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.005 % DRIFT RATE

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION	IN	12/21/2012	COOLING TOWER: LVD BOILER (CONTACT) ID#15G	2500 GPM	PARTICULATE MATTER, FILTERABLE (FPM)	DRIFT ELIMINATOR; DO NOT USE CHROMIUM-BASED WATER TREATMENT CHEMICALS IN ANY OF THE COOLING TOWERS.	0.005 % DRIFT RATE
GARYVILLE REFINERY	LA	12/27/2006	COOLING TOWER NOS. 1 & 2 (24-08 & 32-08) & HYDROGEN PLANT COOLING TOWER (53-08)		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.005 PERCENT
LION OIL COMPANY	AR	10/01/2007	#9 COOLING TOWER, SN-853-9	10.5 BILLION GAL/12-MONTH	PARTICULATE MATTER (PM)		DRIFT ELIMINATORS, 0.005%
CHOUTEAU POWER PLANT	OK	01/23/2009	COOLING TOWER	9 CELLS	PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATORS	
PLAQUEMINE PVC PLANT	LA	02/27/2009	C/A COOLING TOWER (C-4)	38,750 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	GOOD DESIGN, MAINTENANCE, AND INTEGRATED DRIFT ELIMINATORS	
PLAQUEMINE PVC PLANT	LA	02/27/2009	VCM COOLING TOWER (M-7)	106,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	GOOD DESIGN, MAINTENANCE, AND INTEGRATED DRIFT ELIMINATORS	
PLAQUEMINE PVC PLANT	LA	02/27/2009	COOLING TOWER (P-15)	43,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	GOOD DESIGN, MAINTENANCE, AND INTEGRATED DRIFT ELIMINATORS	
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	03/07/2014	3 CELL WET MECHANICAL COOLING TOWER	13,000 GAL/M	PARTICULATE MATTER, FILTERABLE 10 (FPM10)		

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	03/07/2014	3 CELL WET MECHANICAL COOLING TOWER	13,000 GAL/M	PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)		
ARSENAL HILL POWER PLANT	LA	03/20/2008	COOLING TOWER	140,000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	USE OF MIST ELIMINATORS	
NRG COAL HANDLING PLANT	TX	04/13/2006	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)		
MARSHALLTOWN GENERATING STATION	IA	04/14/2014	COOLING TOWER	160,000 GALLONS/MINUTE	PARTICULATE MATTER, TOTAL (TPM)	MIST ELIMINATOR	
GOLDEN GRAIN ENERGY	IA	04/19/2006	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	MIST ELIMINATOR	
SOUTHWEST IOWA RENEWABLE ENERGY	IA	04/19/2007	COOLING TOWERS	3,000,000 GAL/H	VISIBLE EMISSIONS (VE)	MIST ELIMINATOR	
MAG PELLET LLC	IN	04/24/2014	COOLING TOWERS	4600 GPM OF CIRCULATION WATER	PARTICULATE MATTER, FILTERABLE 10 (FPM10)		
MAG PELLET LLC	IN	04/24/2014	COOLING TOWERS	4600 GPM OF CIRCULATION WATER	PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)		
MAG PELLET LLC	IN	04/24/2014	COOLING TOWERS	4600 GPM OF CIRCULATION WATER	PARTICULATE MATTER, FILTERABLE (FPM)		

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
WESTERN GREENBRIER CO-GENERATION, LLC	WV	04/26/2006	COOLING TOWER	55,000 GPM	PARTICULATE MATTER (PM)	DRIFT ELIMINATORS @ 0.0005% DRIFT RATE	
ENID NITROGEN PLANT	OK	05/01/2008	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)	HIGH-EFFICIENCY DRIFT ELIMINATOR	
NEW STEEL INTERNATIONAL, INC., HAVERHILL	OH	05/06/2008	COOLING TOWERS (12)	1,440,000 GAL/H	PARTICULATE MATTER (PM)	DRIFT ELIMINATORS	
NEW STEEL INTERNATIONAL, INC., HAVERHILL	OH	05/06/2008	COOLING TOWERS (12)	1,440,000 GAL/H	PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)	DRIFT ELIMINATORS	
EMBERCLEAR GTL MS	MS	05/08/2014	INDUCED DRAFT COOLING TOWER	1420 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	HIGH EFFICIENCY DRIFT ELIMINATORS	
ACTIVATED CARBON FACILITY	LA	05/28/2008	COOLING TOWERS	10,750 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATION SYSTEM	
OREGON CLEAN ENERGY CENTER	OH	06/18/2013	MECHANICAL DRAFT WET COOLING TOWER, 16 CELL	322,000 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)		
OREGON CLEAN ENERGY CENTER	OH	06/18/2013	MECHANICAL DRAFT WET COOLING TOWER, 16 CELL	322,000 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		
LANGLEY GULCH POWER PLANT	ID	06/25/2010	COOLING TOWER	63,200 GPM	PARTICULATE MATTER (PM)	DRIFT ELIMINATORS, GOOD OPERATING PRACTICES	

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007	INDUSTRIAL COOLING TOWER	150,000 GPM	VISIBLE EMISSIONS (VE)	DRIFT ELIMINATORS	
SHINTECH PLAQUEMINE PLANT 2	LA	07/10/2008	EQT120 COOLING TOWER (2C-4)	38,750 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	GOOD DESIGNS, GOOD MAINTENANCE, AND MIST ELIMINATORS	
SHINTECH PLAQUEMINE PLANT 2	LA	07/10/2008	EQT128 - COOLING TOWER (2M-7)	106,000 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)	GOOD DESIGN, GOOD MAINTENANCE, AND MIST ELIMINATORS	
CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	07/12/2013	COOLING TOWERS		VISIBLE EMISSIONS (VE)	DRIFT ELIMINATOR	
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007	COOLING TOWER, F80 (07-A-979P)	50,000 GPM	VISIBLE EMISSIONS (VE)	DRIFT ELEIMIANTOR / DEMISTER	
ASA BLOOMINGBURG, LLC	OH	08/10/2006	COOLING TOWER	3,300,000 GAL/H	VISIBLE EMISSIONS (VE)	PARAMETRIC MONITORING OF THE DRIFT ELIMINATOR. MAXIMUM DRIFT LOSS FACTOR OF 0.005%	
HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009	COOLING TOWER - UNIT BA14	20,400 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	BACT CONSISTS OF THE TWO REQUIREMENTS DESCRIBED IN THE PROCESS.	
NORCO HYDROGEN PLANT	LA	09/04/2012	COOLING TOWER (EQT0004)	11,200 GPM	PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATORS	
MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007	COOLING TOWER		VISIBLE EMISSIONS (VE)	DESIGNED TO MINIMIZE DRIFT	

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
MID AMERICAN STEEL ROLLING MILL	OK	09/08/2008	COOLING TOWERS	3000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	HIGH-EFFICIENCY DRAFT ELIMINATORS	
CANE ISLAND POWER PARK	FL	09/08/2008	AN EIGHT-CELL MECHANICAL COOLING TOWER		PARTICULATE MATTER, TOTAL 10 (TPM10)		
TATE & LYLE INDGREDIENTS AMERICAS, INC.	IA	09/19/2008	COOLING TOWER		VISIBLE EMISSIONS (VE)	DRIFT ELIMINATORS	
IPL EAGLE VALLEY GENERATING STATION	IN	10/11/2013	COOLING TOWER EU-7	192,000 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	COMBUSTION DESIGN CONTROL	
IPL EAGLE VALLEY GENERATING STATION	IN	10/11/2013	COOLING TOWER EU-7	192,000 GPM	PARTICULATE MATTER, TOTAL (TPM)	COMBUSTION DESIGN CONTROL	
BURNEY MOUNTAIN POWER	CA	10/21/2010	EVAPORATIVE COOLING TOWER	7600 GPM	PARTICULATE MATTER, FUGITIVE	SEE WORK PRACTICE REQUIREMENTS IN NOTES	
SAPPI CLOQUET LLC	MN	10/28/2009	COOLING TOWER		PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	DRIFT ELIMINATORS	
CPV ST CHARLES	MD	11/12/2008	COOLING TOWER		PARTICULATE MATTER (PM)		
CPV ST CHARLES	MD	11/12/2008	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 10 (FPM10)		

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
CPV ST CHARLES	MD	11/12/2008	COOLING TOWER		PARTICULATE MATTER, FILTERABLE 2.5 (FPM2.5)		
ST. CHARLES REFINERY	LA	11/17/2009	COOLING TOWERS (13-81, 2004-6, 2005-42, 2005-43, 2008-35)		PARTICULATE MATTER, TOTAL 10 (TPM10)	DRIFT ELIMINATORS	
OHIO RIVER CLEAN FUELS, LLC	OH	11/20/2008	COOLING TOWERS	120,425 T/H	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	HIGH EFFICIENCY DRIFT ELIMINATORS	
OHIO RIVER CLEAN FUELS, LLC	OH	11/20/2008	COOLING TOWERS	120,425 T/H	VISIBLE EMISSIONS (VE)	HIGH EFFICIENCY DRIFT ELIMINATORS	
MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	COOLING TOWER	159,000 GPM	PARTICULATE MATTER, TOTAL 10 (TPM10)		
MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	COOLING TOWER	159,000 GPM	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		
MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	COOLING TOWER	159,000 GPM	PARTICULATE MATTER, TOTAL (TPM)	DRIFT ELIMINATOR	
LITTLE GYPSY GENERATING PLANT	LA	11/30/2007	COOLING TOWER	5000 GPM	PARTICULATE MATTER, FILTERABLE 10 (FPM10)	DRIFT ELIMINATOR WITH A 99.999% CONTROL EFFICIENCY	

RACT/BACT/LAER Clearinghouse (RBLC) Data for Cooling Towers

FACILITY NAME	STATE	PERMIT DATE	EMISSIONS SOURCE	COOLING TOWER CAPACITY	POLLUTANT	CONTROL DESCRIPTION	PM EMISSION LIMIT
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/04/2013	COOLING TOWER -- WET MECHANICAL DRAFT (EUCOOLTWR)	0	PARTICULATE MATTER, TOTAL 10 (TPM10)	MIST/DRIFT ELIMINATORS.	
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/04/2013	COOLING TOWER -- WET MECHANICAL DRAFT (EUCOOLTWR)	0	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)	MIST/DRIFT ELIMINATORS	
ANCLOTE POWER PLANT	FL	12/22/2006	COOLING TOWERS	660,000 GPM	PARTICULATE MATTER (PM)	DRIFT ELIMINATORS	
NUCOR STEEL MARION, INC.	OH	12/23/2010	MELT SHOP SPRAY CONTACT COOLING TOWER	198,360 GAL/H	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		
NUCOR STEEL MARION, INC.	OH	12/23/2010	ROLLING MILL CONTACT COOLING TOWER	225,000 GAL/H	PARTICULATE MATTER, TOTAL 2.5 (TPM2.5)		
NUCOR STEEL MARION, INC.	OH	12/23/2010	MELT SHOP SPRAY CONTACT COOLING TOWER	198,360 GAL/H	PARTICULATE MATTER, TOTAL (TPM)		
NUCOR STEEL MARION, INC.	OH	12/23/2010	ROLLING MILL CONTACT COOLING TOWER	225,000 GAL/H	PARTICULATE MATTER, TOTAL (TPM)		
NUCOR STEEL MARION, INC.	OH	12/23/2010	MELT SHOP SPRAY CONTACT COOLING TOWER	198,360 GAL/H	VISIBLE EMISSIONS (VE)		
NUCOR STEEL MARION, INC.	OH	12/23/2010	ROLLING MILL CONTACT COOLING TOWER	225,000 GAL/H	VISIBLE EMISSIONS (VE)		

Attachment 5

SL-013397 O&M Assessment Report

SALT RIVER PROJECT
SANTAN GENERATING STATION

SANTAN EMISSIONS OPERATING AND MAINTENANCE PRACTICES ASSESSMENT REPORT

SL-013397
Rev. 0
FINAL

Prepared By:

Project No. 12046-021
August 18, 2016

NOTICE

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CERTIFICATION

FOR

SALT RIVER PROJECT

SANTAN GENERATING STATION

SANTAN EMISSIONS – OPERATING AND MAINTENANCE PRACTICES ASSESSMENT REPORT

I CERTIFY THAT THIS REPORT WAS PREPARED BY ME OR UNDER MY SUPERVISION AND THAT I AM A REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARIZONA.

Electronic copy of final document;

Sealed original is with Nelson Rosado

Certificate No. 58529

REVISION	CERTIFIED BY	DATE
0	Nelson Rosado	August 18, 2016

APPROVAL PAGE

FOR

SALT RIVER PROJECT

SANTAN GENERATING STATION

SANTAN EMISSIONS – OPERATING AND MAINTENANCE PRACTICES ASSESSMENT REPORT

Rev.	Date/ Purpose	Prepared	Reviewed	Approved
0	8/18/2016 Final	Scott M for D. Nunez	Scott M for M. Dowd	Nelson R N. Rosado

TABLE OF CONTENTS

1.0 INTRODUCTION

Per Condition 38 of the Certificate of Environmental Compatibility (CEC) issued by the Arizona Corporation Commission (ACC), SRP is required to perform an air emissions assessment for Santan Generating Station (SGS) every five (5) years. This assessment is to investigate the possibility of reducing emissions from current operating levels by either: a) changing operating and maintenance (O&M) practices or b) implementing new emissions reduction technologies.

Proper operations and maintenance of plant equipment plays a key role in maintaining air emission levels. This report contains S&L's assessment of the current O&M processes and programs utilized at SGS with respect to maintaining and reducing existing air emissions. A separate report will be provided to address emissions reductions, and associated costs, for implementing new technologies as applicable.

The O&M processes and programs associated with the emission sources listed below were reviewed as part of this assessment.

i. Units S1-S4 Combustion Turbines
ii. Units S5A, S5B and S6A Combustion Turbines & HRSGs (w/duct burners)
iii. Cooling Towers CT1, CT5 and CT6
iv. Emergency Fire Pump
v. Emergency Diesel Generators
vi. Abrasive Blasting Equipment
vii. Fugitive Dust Control
viii. Paint Booth – Has been removed from service.

2.0 ASSESSMENT APPROACH

The approach to the O&M practices assessment encompassed reviewing SRP's Title V Permit V95-008 Rev 2.0.0.0 (renewal date 9/21/2015), conducting a site visit, reviewing plant O&M documentation, and discussing O&M practices with key plant technical, operating, and maintenance personnel. S&L reviewed documentation and data supplied by SRP to become familiar with the units' operating histories and performance and to determine areas of review that would require attention during the site visit. During the site visit, S&L reviewed the following types of documents:

- Inspection Reports
- Operator and Maintenance Logs
- Equipment Manuals and Data Sheets
- Listing of Preventive Maintenance Tasks and Work Orders

3.0 OPERATIONS & MAINTENANCE PLANS

3.1 Discussion

The Title V Permit has many conditions that are directed towards the operating and maintenance practices for the permitted equipment. The most stringent of these conditions requires SRP to follow an established Operations and Maintenance Plan which specifies the procedures used to operate and maintain a specific piece of equipment. The four (4) items listed below are subject to this condition:

- S1 – S4 Dry Low-NOx Burners
- S1 – S4 CO Oxidation Catalyst Emissions Control System
- S5A, S5B and S6A CO Oxidation Catalyst Emissions Control System
- S5A, S5B and S6A Selective Catalytic Reduction System

The O&M Plan must specify operating parameters to be monitored to assure compliance, the methodology to be utilized to record the operating parameter, and the maintenance procedures to be performed along with the frequency of each procedure.

In addition, SGS has a Blast Booth on its Equipment List (Appendix A of the permit). Specific Condition 25 of the permit refers the Permittee to County Rule 312 for Abrasive Blasting activities. County Rule 312 requires an O&M Plan for Abrasive Blasting.

3.2 S&L Review

S&L reviewed the O&M Plans for the listed equipment and found them to be consistent with standard industry practices for content and frequency. S&L also reviewed the maintenance history for the procedures specified and found them complete and without any indications that equipment was malfunctioning. An overview of the equipment O&M Plans is provided in the following sections.

3.2.1 Units S1 - S4 Dry Low NOx Burners and CO Oxidation Catalyst Emissions Control

The S1 – S4 Dry Low-NOx Burners and CO Oxidation Catalyst Emissions Control and Continuous Emissions Monitoring System (CEMS) is combined into one O&M Plan that addresses NOx and CO emissions along with CEMS maintenance. For this Plan, the CEMS is utilized to measure NOx as the operating parameter, and combustion inspections are scheduled as the maintenance procedure. The burners installed are designed to minimize NOx formation during the combustion process. The burners are an assembly of components such as nozzles, liners, igniters, flame scanners, etc. These components are inspected for wear and replaced or repaired as required to assure optimal performance. The CO catalysts for Units S-1 through S-4 were replaced in 2013. The Englehard manual for Units S1 – S4 was reviewed as part of this assessment. These documents are used in conjunction with the procedures in the aforementioned O&M plan to provide additional guidance.
The SGS maintenance records indicate that these inspections/repairs were completed on the recommended intervals.

3.2.2 Units S-5A-S6A CO Catalyst & SCR System

The CO Catalyst and SCR Systems are combined into one O&M Plan. Operating parameters include the CEMS measurement of CO and NOx, and other system temperatures and pressures that assure operation within the appropriate ranges for the chemical reactions to occur. The maintenance procedures in the plan identify preventive maintenance activities such as device calibrations and catalyst inspections. Replacement activities associated with filter and catalyst replacement are also addressed. A review of the maintenance records indicates these procedures are being followed.

The Cormetech CO Catalyst Handling and Maintenance manual for Units S5A, S5B, and S6A was reviewed as part of this assessment. These documents are used in conjunction with the procedures in the aforementioned O&M plan to provide additional guidance.

The SCR and CO catalysts were replaced on Units S5A, S5B and S6A in the first quarter of 2015. Replacement data sheets were reviewed by S&L ; the new catalysts meet original manufacturer's specifications and the permit requirements.

3.2.3 Dust Collector for Abrasive Blasting Equipment

The Dust Collector O&M Plan addresses particulate emissions associated with sandblasting activities. An abrasive blast shed is utilized to clean parts and equipment. Dust and particles from the cleaning process are collected on the outside of cartridge filter elements located inside of the dust collector. The filter elements are pulse cleaned using compressed air, and the particulate material is captured in a hopper and storage container for disposal.

To help assure proper equipment operation, the operating plan requires visual emissions observations, and monitoring of the filter pressure drop each operating day. The maintenance plan identifies procedures for performing time-based preventative maintenance activities. These activities were reviewed and are appropriate for minimizing emissions from the type of dust collector installed at SGS.

The Abrasive Blasting outside of the Baghouse Log, Dust Collector Daily Log, Maintenance Inspection of Blast Building Dust Collector work order and Santan Kyrene Operating Procedure (SKOP) 126 were reviewed; they are complete and in compliance with the permit.

4.0 SUPPLEMENTAL PERMIT REQUIREMENTS

4.1 Discussion

4.1.1 Internal Combustion Engines

The permit requires that the internal combustion (diesel and propane fueled) engines for the emergency fire pump and emergency generators operate only during emergency conditions or routine maintenance checks (testing). The routine maintenance check running time for each engine is limited to 37.5 hours per year on a rolling twelve-month basis for the diesel fire pump and sump pump generator and 100 hours per year for the turning gear and switchyard generator.

4.1.2 Fugitive Dust Control Plan

The permit requires the station develop and implement a fugitive dust control plan, which includes monitoring and mitigation of fugitive dust that are generated by routine plant activities that occur onsite.

4.1.3 Gasoline tank

In addition, SGS has a 500 gallon gasoline tank on its Equipment List (Appendix A of the permit). The permit requires no leaks through the walls of piping, fitting, fill hose(s) and vapor hose(s). Inspection of the tank, fittings and fill pipes are to be made either weekly or if deliveries are less than weekly, inspection and recording of the inspection at the time of each delivery.

4.1.4 Cooling Towers

The permit requires that Santan Generating Station inspect the cooling tower drift eliminators monthly for proper operation only if the drift eliminator can be viewed safely and does not require the Permittee to walk the tower. If the drift eliminators cannot be safely inspected monthly, then they must be inspected for integrity during a regularly scheduled outage when the cooling tower is not operating. This visual inspection shall be no less than once per year.

4.2 S&L Review

4.2.1 Internal Combustion Engines

Based upon discussions with operating personnel, S&L understands that the operating practices described below are currently utilized for performing routine checks on the internal combustion engines and per the Computerized Maintenance Management System (CMMS) as described in section 5.

The fire pump (one for the entire site) is tested on a weekly schedule while the emergency generators (two, installed on site) are run on a monthly schedule. The duration of the weekly test is 30 minutes and the duration for the monthly tests is 10 minutes; therefore the engines are operated within the permit requirements for routine checks. All engines are run for two hours during the annual load testing.

In addition, a propane-fired emergency generator is installed in the switchyard at SGS to charge the substation batteries as necessary during an extended outage. This engine is tested monthly for up to 15 minutes, quarterly for approximately an hour for quarterly checks, and an additional hour annually for annual checks. This engine is also given an annual two hour load test. The total run time is approximately 12 hours per year for testing and maintenance.

Maintenance on the internal combustion engines is performed by skilled technicians from the plant, personnel assigned to the substation, as well as by a local maintenance firm. Information from test runs and maintenance are logged.

These are reasonable operating practices that maintain equipment reliability while minimizing wear.

4.2.2 Dust Control Plan

The site dust control plan identifies the primary control measure as ground cover in the form of asphalt or gravel for the site. Operations visually inspects the site on a daily basis and completes the Daily Dust Control Inspection Log. Based on information reviewed, the station has taken adequate actions to mitigate the occurrence of fugitive dust as noted in the plan.

4.2.3 Gasoline Tanks

S&L reviewed delivery bill of ladings for quantities and gasoline inspection records to assure total throughput was less than 120,000 gallons in any 12 consecutive calendar months and inspections were occurring at the time of delivery. Based on the documentation reviewed, the station is complying with the Permit.

4.2.4 Cooling Towers

S&L reviewed engineering inspection reports pertaining to the cooling tower as part of this assessment. The monthly inspection records were complete and indicate an adequate inspection program is in place.

5.0 WORK MANAGEMENT

5.1 Background & Discussion

Work Management is the process by which maintenance, modifications, surveillances, testing, engineering support, and other work activities requiring plant coordination or schedule integration are implemented. An effective work management process does the following:

- Promotes safety.
- Improves equipment performance and system health.
- Provides a proper methodology for work prioritization to ensure activities are performed in the right time frame.
- Increases productivity and reduce costs through the efficient use of resources.
- Provides for a long-range plan to include major design changes, as well as predictive and preventive maintenance activities.
- Incorporates an effective feedback loop that promotes and ensures continual process improvement.

As part of the Work Management Process, maintenance planning and scheduling is a disciplined approach to maintain equipment performance, reduce downtime and minimize overall costs. This is accomplished through:

- Prioritizing work
- Developing the physical steps to complete the job
- Procuring necessary tools and materials
- Scheduling the work to be done
- Identifying any additional work to be completed on the equipment
- Filing written documentation for equipment history

A Computerized Maintenance Management System (CMMS) maintains a database of information about a facility's equipment and maintenance history. This information is used to assist maintenance workers in the performance of their work activities and to help management make informed decisions. A CMMS typically has capabilities regarding:

- Work orders
- Preventive maintenance
- Asset management
- Inventory control
- Safety/Permits

5.2 S&L Review

Based on discussions with plant personnel, Santan Generating Station utilizes a Work Management process. Upcoming work activities are prioritized and scheduled through a planning and scheduling organization. For immediate "fix-it-now" items, maintenance resources are made available to the operating staff.

MAXIMO is the CMMS software utilized by Salt River Project. The system has the capability to provide equipment history, manage parts inventory, create work orders for scheduled work, and provide management reporting. MAXIMO is a comprehensive work management system that can provide both resource planning and work measurement information to management.

6.0 PREVENTIVE AND PREDICTIVE MAINTENANCE

6.1 Background Discussion

Preventive Maintenance (PM) can be defined as tests, measurements, adjustments, and parts replacement, performed specifically to prevent faults from occurring. Preventive maintenance is conducted to keep equipment working properly and/or extend the life of the equipment. Preventive maintenance activities include partial or complete overhauls at specified periods, oil changes, lubrication and so on. In addition, workers can record equipment deterioration so they know to replace or repair worn parts before they cause system failure. The ideal preventive maintenance program would prevent all equipment failure before it occurs.

Predictive Maintenance (PdM) techniques help determine the condition of in-service equipment in order to predict when maintenance should be performed. This approach offers cost savings over routine or time-based preventive maintenance because tasks are performed only when warranted. PdM, or condition-based maintenance, attempts to evaluate the condition of equipment by performing periodic or continuous (online) equipment condition monitoring. The ultimate goal of PdM is to perform maintenance at a scheduled point in time when the maintenance activity is most cost-effective and before the equipment loses optimum performance.

6.2 S&L Review

S&L reviewed the preventive maintenance program used at SGS. The program consists of tasks with associated instructions which are stored in MAXIMO. These tasks apply to the complete site and many of these specifically pertain to equipment covered by this emissions assessment. These PM tasks were developed utilizing manufacturers' recommendations, industry standards and plant experience. MAXIMO is also utilized to manage equipment inspections. S&L's review indicates that the Santan PM program is comprehensive in scope, tasks are appropriately scheduled, and findings are stored in the system for further use.

Santan Generating Station also has a predictive maintenance program in place. Although not reviewed in detail for this assessment, this program includes both vibration analysis and lubrication oil analysis, both of which are designed to detect equipment degradation prior to failure.

Finally, Santan utilizes several performance monitoring systems to assure proper operation of the equipment. These systems include:

a. Santan has recently installed and is utilizing ECOMAX^R Combustion Optimization system by Ethos Energy on Units S-5A, S-5B and S-6A. The system continually monitors and adjusts (tunes) key combustion control parameters to maintain NO_x and CO compliance, flame stability and acceptable combustion dynamics. The system was in use by operations at the time of the S&L review.

b. Santan is utilizing the EtaPRO performance monitoring system developed by General Physics Corporation. The main intent of this system is to provide operators with accurate instantaneous heat rate monitoring. This system will allow the station to trend its fuel consumption and identify deviations from baseline heat rate. Heat rate degradation is an early indicator of equipment problems.

c. Santan is utilizing a PI data acquisition system. The system also serves as the plant's data historian. PI is an established system used throughout the industry and is a reliable database for equipment performance monitoring.

d. Santan also has the Smart Signal performance monitoring system by GE. Smart Signal monitors equipment to detect and identify events of abnormal behavior by the differences between real-time actual data and predicted normal behavior in lieu of thresholds for actual values. This system also performs diagnostic and prioritization analysis. The system is monitored by a centralized SRP group where any anomalies are reported back to the plant either through an email or a phone call directly to the control room, depending on the severity of the anomaly.

By utilizing these tools, station and generation engineering personnel are able to monitor and trend parameters that may adversely affect operating equipment, thus mitigating emissions issues.

7.0 CONTROL ROOM OPERATIONS

7.1 Discussion

The Santan control room is manned at all times by at least one (1) Control Room Operator (CRO). These CROs are responsible for starting up and shutting down the units, communicating with the dispatch authorities, and assisting in O&M activities at the plant. They are assisted by roving operators who perform equipment surveillances and manual operations required at the equipment.

S&L had discussions with control room operating staff regarding operating flexibility and maintenance activities to understand the interfaces between O&M practices and its impact on unit emissions. Lessons learned are incorporated into the control schemes and operating procedures. The CROs stated they had the necessary personnel resources to manage operations of the facility. At times, in addition to the roving operators, two from the maintenance staff are also included on shift to provide quick response for "fix-it-now" activities. The CROs that spoke with S&L were very knowledgeable about the units, the emission control equipment, parameters monitored, corrective actions and the permit requirements associated with the various pollutants.

7.2 S&L Review

The control systems utilized at Santan are of current vintage. The original controls on Units S1 – S4 have been replaced by an upgraded DCS system. Unit start-up and shutdown controls are essentially programmed into the system and require mainly CRO oversight and response to alarm situations. The SCRs on Units S5A, S5B and S6A are also pre-programmed for automatic start-up and shutdown. S5S, S6A & S6 Cold and Warm Startup Procedures were reviewed with respect to timing of verifications, actions and permissive for starting the SCR system(s). The CROs will input the unit load into the automatic generation control and the dispatching function will move unit load to match the system requirements. The CRO manually starts and stops cooling tower fans to optimize condenser performance. Therefore, there is minimal operator intervention with the emission control equipment under normal operating conditions.

8.0 CONCLUSION

As part of the CEC Condition 38 assessment required by the ACC for Santan Generating Station, this O&M assessment finds that the key elements of a comprehensive integrated Operation and Maintenance program are utilized at SGS. The Santan Generating Station O&M Program encompasses the following activities:

i. A documented Preventive Maintenance and Inspection program for the emission control equipment,
ii. A Preventive / Predictive Maintenance program to maintain equipment reliability and performance,
iii. A Work Management Process to complete station activities efficiently,
iv. Several Performance Monitoring Systems to provide technical information for plant staff,
v. Reliable modern control systems that automate system operations, and
vi. Knowledgeable staff that understands their role in the control of and monitoring of emissions.

The assessment did not find opportunities where a change in operations and maintenance practices would help reduce air emissions without adversely impacting capital assets.

Attachment 6

Santan Units 1-4 NO_X Control Cost Summaries

SRP - Santan Generating Station
NOx Control Cost Summary -- Units 1-4

Unit S1 - NOx Control Costs

Net Generation	90	MW			
Net Generation	88739	MWh			
Capacity Factor:	11.26%				
Actual Annual Fuel Consumption:	789	MMSCF/yr			
Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline CT/HRSG Emissions (DLN1)	97.9	0.096	38.6		
Combustor Upgrades (DLN1+)	39.1	0.038	15.4	60%	23.2
SCR	9.8	0.010	3.9	90%	34.8
SCR + Combustor Upgrades	9.8	0.010	3.9	90%	34.8

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline CT/HRSG Emissions (DLN1)	38.6								
Combustor Upgrades (DLN1+)	15.4	23.2	$5,844,000	$582,000	$73,000	$655,000	**$28,273**		
SCR	3.9	34.8	$14,362,000	$1,430,000	$501,000	$1,931,000	**$55,567**	11.6	$110,156
SCR + Combustor Upgrades	3.9	34.8	$20,206,000	$2,012,000	$559,000	$2,571,000	**$73,984**	11.6	$165,406

Unit S2 - NOx Control Costs

Net Generation	90	MW			
Net Generation	75126	MWh			
Capacity Factor:	9.53%				
Actual Annual Fuel Consumption:	957	MMSCF/yr			
Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline CT/HRSG Emissions (DLN1)	101.0	0.099	48.3		
Combustor Upgrades (DLN1+)	40.4	0.040	19.3	60%	29.0
SCR	10.1	0.010	4.8	90%	43.5
SCR + Combustor Upgrades	10.1	0.010	4.8	90%	43.5

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline CT/HRSG Emissions (DLN1)	48.3								
Combustor Upgrades (DLN1+)	19.3	29.0	$5,844,000	$582,000	$71,000	$653,000	**$22,511**		
SCR	4.8	43.5	$14,362,000	$1,430,000	$496,000	$1,926,000	**$44,263**	14.5	$87,767
SCR + Combustor Upgrades	4.8	43.5	$20,206,000	$2,012,000	$555,000	$2,567,000	**$58,994**	14.5	$131,961

SRP - Santan Generating Station
NOx Control Cost Summary -- Units 1-4

Unit S3 - NOx Control Costs

Net Generation	90	MW
Net Generation	79521	MWh
Capacity Factor:	10.09%	
Actual Annual Fuel Consumption:	710	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline CT/HRSG Emissions (DLN1)	91.7	0.090	32.5		
Combustor Upgrades	36.7	0.036	13.0	60%	19.5
SCR	9.2	0.009	3.3	90%	29.3
SCR + Combustor Upgrades	9.2	0.009	3.3	90%	29.3

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline CT/HRSG Emissions (DLN1)	32.5								
Combustor Upgrades	13.0	19.5	$5,844,000	$582,000	$71,000	$653,000	**$33,443**		
SCR	3.3	29.3	$14,362,000	$1,430,000	$496,000	$1,926,000	**$65,759**	9.8	$130,392
SCR + Combustor Upgrades	3.3	29.3	$20,206,000	$2,012,000	$555,000	$2,567,000	**$87,645**	9.8	$196,048

Unit S4 - NOx Control Costs

Net Generation	90	MW
Net Generation	86954	MWh
Capacity Factor:	11.03%	
Actual Annual Fuel Consumption:	785	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline CT/HRSG Emissions (DLN1)	107.3	0.105	42.1		
Combustor Upgrades (DLN1+)	42.9	0.042	16.8	60%	25.3
SCR	10.7	0.011	4.2	90%	37.9
SCR + Combustor Upgrades	10.7	0.011	4.2	90%	37.9

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline CT/HRSG Emissions (DLN1)	42.1								
Combustor Upgrades (DLN1+)	16.8	25.3	$5,844,000	$582,000	$72,000	$654,000	**$25,887**		
SCR	4.2	37.9	$14,362,000	$1,430,000	$502,000	$1,932,000	**$50,982**	12.6	$101,172
SCR + Combustor Upgrades	4.2	37.9	$20,206,000	$2,012,000	$559,000	$2,571,000	**$67,844**	12.6	$151,758

SRP - Santan Generating Station
Units S1 -- NO_x Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.096**
Post DLN1+ NOx Emission Rate	**0.038**
% NOx Reduction w/ DLN1+	**60%**
Capacity Factor used for Cost Estimates (%)	**11.3%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,938,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates
Total Purchased Equipment Cost (PEC)	$2,938,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,811,000		Based on SRP DLN1 Installation Costs : $4,896,000 for all units in 2000 USD; escalated to 2016 USD using Handy Whitman Escalation Rates
Total Direct Capital Costs (DC)	**$4,749,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$67,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Controls Engineering/Design	$36,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Training	$13,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Field Services	$5,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Total Indirect Capital Costs (IC)	**$121,000**		
Contingency	$974,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$5,844,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$582,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$15,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$15,000		
Fixed O&M Costs			
Additional Operators per shift	0		
Operating Labor	$0		
Supervisory Labor	$0		
Annual Maintenance Cost	$58,000	1.0%	Maintenance cost estimated based on replacement of combustor parts. Estimated 1%.
Total Fixed O&M Cost	$58,000		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$73,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$582,000**		
Annual Operating Cost	**$73,000**		
Total Annual Cost	**$655,000**		

SRP - Santan Generating Station
Units S2 -- NO_x Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.099**
Post DLN1+ NOx Emission Rate	**0.040**
% NOx Reduction w/ DLN1+	**60%**
Capacity Factor used for Cost Estimates (%)	**9.5%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,938,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates
Total Purchased Equipment Cost (PEC)	$2,938,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,811,000		Based on SRP DLN1 Installation Costs : $4,896,000 for all units in 2000 USD; escalated to 2016 USD using Handy Whitman Escalation Rates
Total Direct Capital Costs (DC)	**$4,749,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$67,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Controls Engineering/Design	$36,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Training	$13,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Field Services	$5,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Total Indirect Capital Costs (IC)	**$121,000**		
Contingency	$974,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$5,844,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$582,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$13,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$13,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Annual Maintenance Cost	$58,000	1.0%	Maintenance cost estimated based on replacement of combustor parts. Estimated 1%.
Total Fixed O&M Cost	$58,000		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$71,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$582,000**		
Annual Operating Cost	**$71,000**		
Total Annual Cost	**$653,000**		

SRP - Santan Generating Station
Units S3 -- NO_x Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.090**
Post DLN1+ NOx Emission Rate	**0.036**
% NOx Reduction w/ DLN1+	**60%**
Capacity Factor used for Cost Estimates (%)	**10.1%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,938,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates
Total Purchased Equipment Cost (PEC)	$2,938,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,811,000		Based on SRP DLN1 Installation Costs : $4,896,000 for all units in 2000 USD; escalated to 2016 USD using Handy Whitman Escalation Rates
Total Direct Capital Costs (DC)	**$4,749,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$67,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Controls Engineering/Design	$36,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Training	$13,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Field Services	$5,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Total Indirect Capital Costs (IC)	**$121,000**		
Contingency	$974,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$5,844,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$582,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$13,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$13,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Annual Maintenance Cost	$58,000	1.0%	Maintenance cost estimated based on replacement of combustor parts. Estimated 1%.
Total Fixed O&M Cost	$58,000		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$71,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$582,000**		
Annual Operating Cost	**$71,000**		
Total Annual Cost	**$653,000**		

SRP - Santan Generating Station
Units S4 -- NO_x Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.105**
Post DLN1+ NOx Emission Rate	**0.042**
% NOx Reduction w/ DLN1+	**60%**
Capacity Factor used for Cost Estimates (%)	**11.0%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,938,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates
Total Purchased Equipment Cost (PEC)	$2,938,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,811,000		Based on SRP DLN1 Installation Costs : $4,896,000 for all units in 2000 USD; escalated to 2016 USD using Handy Whitman Escalation Rates
Total Direct Capital Costs (DC)	**$4,749,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$67,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Controls Engineering/Design	$36,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Training	$13,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Field Services	$5,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Total Indirect Capital Costs (IC)	**$121,000**		
Contingency	$974,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$5,844,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$582,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$14,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$14,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Annual Maintenance Cost	$58,000	1.0%	Maintenance cost estimated based on replacement of combustor parts. Estimated 1%.
Total Fixed O&M Cost	$58,000		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$72,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$582,000**		
Annual Operating Cost	**$72,000**		
Total Annual Cost	**$654,000**		

SRP - Santan Generating Station
Unit S1 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.096**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.010**
% Reduction w/ SCR	**90%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**11.3%**

CAPITAL COSTS	**[$]**			**Basis**
Direct Capital Costs				
NOx Control Equipment	$10,589,000			Based on SRP (APS) turnkey estimate of $9,081,150 (2010 USD), which includes catalyst placed in middle of evap section, raised piping, tubes, drums, stack by 30 ft. Esclated from 2010 USD to 2016 USD.
Instrumentation	$0			Included in NOx control equipment cost
Sales Taxes	$0			Included in NOx control equipment cost
Freight	$0			Included in NOx control equipment cost
Total Purchased Equipment Cost	$10,589,000			
Direct Installation Costs				
Installation	$1,379,000			Based on SRP cost estimate, includes engineering/design and installation ($1,255,000 2010 USD); Escalated to 2016 USD
Total Direct Capital Costs (DC)	**$11,968,000**			Sum of purchased equipment costs and installation costs
Indirect Capital Costs				
Engineering	$0			Included in NOx control direct installation costs
Construction and Field Expenses	$0			Included in NOx control direct installation costs
Contractor Fees	$0			Included in NOx control direct installation costs
Start-Up	$0			Included in NOx control direct installation costs
Performance Testing	$0			Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**			
Contingency	$2,394,000		20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$14,362,000**			sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996		20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,430,000**		7.70%	pretax marginal rate of return on private investment
OPERATING COSTS				**Basis**
Operating & Maintenance Costs				
Variable O&M Costs				
Ammonia Injection Rate (lb/hr)	52		0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560		18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$25,000	$	963	Based on ammonia injection rate ammonia reagent cost of $963/ton.
Catalyst Replacement Cost	$66,000		5.0	Based on catalyst cost of $7500/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$	500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$8,000		2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$103,000			
Fixed O&M Costs				
Additional Operators per shift	0.50			Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$153,000			Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$23,000		15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$215,000		1.5%	of TCI. Engineering judgment. 0.5% in cost manual (EPA Cost Manual Ch. 2, Page 2.73 [Eq. 2.57]) is expected for large coal boilers, not combined cycle.
Total Fixed O&M Cost	$391,000			
Indirect Operating Cost				
Property Taxes	$0		0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0		0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$7,000		3%	of the Annual Operating Labor & 40% of Maintenance Costs. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78 (Eq. 2.68 and 2.69)
Total Indirect Operating Cost	$7,000			
Total Annual Operating Cost	**$501,000**			
TOTAL ANNUAL COST				
Annualized Capital Cost	**$1,430,000**			
Annual Operating Cost	**$501,000**			
Total Annual Cost	**$1,931,000**			

SRP - Santan Generating Station
Unit S2 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.099**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.010**
% Reduction w/ SCR	**90%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**9.5%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$10,589,000		Based on SRP (APS) turnkey estimate of $9,081,150 (2010 USD), which includes catalyst placed in middle of evap section, raised piping, tubes, drums, stack by 30 ft. Esclated from 2010 USD to 2016 USD.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$10,589,000		
Direct Installation Costs			
Installation	$1,379,000		Based on SRP cost estimate, includes engineering/design and installation ($1,255,000 2010 USD); Escalated to 2016 USD
Total Direct Capital Costs (DC)	**$11,968,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,394,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$14,362,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,430,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	53	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$21,000	$ 963	Based on ammonia injection rate ammonia reagent cost of $963/ton.
Catalyst Replacement Cost	$66,000	5.0	Based on catalyst cost of $7500/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$7,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$98,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$153,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$23,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$215,000	1.5%	of TCI. Engineering judgment. 0.5% in cost manual (EPA Cost Manual Ch. 2, Page 2.73 [Eq. 2.57]) is expected for large coal boilers, not combined cycle.
Total Fixed O&M Cost	$391,000		
Indirect Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$7,000	3%	of the Annual Operating Labor & 40% of Maintenance Costs. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78 (Eq. 2.68 and 2.69)
Total Indirect Operating Cost	$7,000		
Total Annual Operating Cost	**$496,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,430,000**		
Annual Operating Cost	**$496,000**		
Total Annual Cost	**$1,926,000**		

SRP - Santan Generating Station
Unit S3 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.090**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.009**
% Reduction w/ SCR	**90%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**10.1%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$10,589,000		Based on SRP (APS) turnkey estimate of $9,081,150 (2010 USD), which includes catalyst placed in middle of evap section, raised piping, tubes, drums, stack by 30 ft. Esclated from 2010 USD to 2016 USD.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$10,589,000		
Direct Installation Costs			
Installation	$1,379,000		Based on SRP cost estimate, includes engineering/design and installation ($1,255,000 2010 USD); Escalated to 2016 USD
Total Direct Capital Costs (DC)	**$11,968,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,394,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$14,362,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,430,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	49	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$21,000	$ 963	Based on ammonia injection rate ammonia reagent cost of $963/ton.
Catalyst Replacement Cost	$66,000	5.0	Based on catalyst cost of $7500/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$7,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$98,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$153,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$23,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$215,000	1.5%	of TCI. Engineering judgment. 0.5% in cost manual (EPA Cost Manual Ch. 2, Page 2.73 [Eq. 2.57]) is expected for large coal boilers, not combined cycle.
Total Fixed O&M Cost	$391,000		
Indirect Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$7,000	3%	of the Annual Operating Labor & 40% of Maintenance Costs. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78 (Eq. 2.68 and 2.69)
Total Indirect Operating Cost	$7,000		
Total Annual Operating Cost	**$496,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,430,000**		
Annual Operating Cost	**$496,000**		
Total Annual Cost	**$1,926,000**		

SRP - Santan Generating Station
Unit S4 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.105**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.011**
% Reduction w/ SCR	**90%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**11.0%**

CAPITAL COSTS	**[$]**			**Basis**
Direct Capital Costs				
NOx Control Equipment	$10,589,000			Based on SRP (APS) turnkey estimate of $9,081,150 (2010 USD), which includes catalyst placed in middle of evap section, raised piping, tubes, drums, stack by 30 ft. Esclated from 2010 USD to 2016 USD.
Instrumentation	$0			Included in NOx control equipment cost
Sales Taxes	$0			Included in NOx control equipment cost
Freight	$0			Included in NOx control equipment cost
Total Purchased Equipment Cost	$10,589,000			
Direct Installation Costs				
Installation	$1,379,000			Based on SRP cost estimate, includes engineering/design and installation ($1,255,000 2010 USD); Escalated to 2016 USD
Total Direct Capital Costs (DC)	**$11,968,000**			Sum of purchased equipment costs and installation costs
Indirect Capital Costs				
Engineering	$0			Included in NOx control direct installation costs
Construction and Field Expenses	$0			Included in NOx control direct installation costs
Contractor Fees	$0			Included in NOx control direct installation costs
Start-Up	$0			Included in NOx control direct installation costs
Performance Testing	$0			Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**			
Contingency	$2,394,000		20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$14,362,000**			sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996		20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,430,000**		7.70%	pretax marginal rate of return on private investment
OPERATING COSTS				**Basis**
Operating & Maintenance Costs				
Variable O&M Costs				
Ammonia Injection Rate (lb/hr)	56		0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560		18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$26,000	$	963	Based on ammonia injection rate ammonia reagent cost of $963/ton.
Catalyst Replacement Cost	$66,000		5.0	Based on catalyst cost of $7500/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$	500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$8,000		2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$104,000			
Fixed O&M Costs				
Additional Operators per shift	0.50			Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$153,000			Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$23,000		15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$215,000		1.5%	of TCI. Engineering judgment. 0.5% in cost manual (EPA Cost Manual Ch. 2, Page 2.73 [Eq. 2.57]) is expected for large coal boilers, not combined cycle.
Total Fixed O&M Cost	$391,000			
Indirect Operating Cost				
Property Taxes	$0		0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0		0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$7,000		3%	of the Annual Operating Labor & 40% of Maintenance Costs. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78 (Eq. 2.68 and 2.69)
Total Indirect Operating Cost	$7,000			
Total Annual Operating Cost	**$502,000**			
TOTAL ANNUAL COST				
Annualized Capital Cost	**$1,430,000**			
Annual Operating Cost	**$502,000**			
Total Annual Cost	**$1,932,000**			

SRP - Santan Generating Station
Unit S1 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.038**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.010**
% Reduction w/ SCR	**75%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**11.3%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$10,589,000		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates. Based on SRP (APS) turnkey estimate of $9,081,150 (2010 USD), which includes catalyst placed in middle of evap section, raised piping, tubes, drums, stack by 30 ft. Esclated from 2010 USD to 2016 USD.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$10,589,000		
Direct Installation Costs			
Installation	$1,379,000		Based on SRP cost estimate, includes engineering/design and installation ($1,255,000 2010 USD); Escalated to 2016 USD
Total Direct Capital Costs (DC)	**$11,968,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,394,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$14,362,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,430,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	22	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$10,000	$ 963	Based on ammonia injection rate ammonia reagent cost of $963/ton.
Catalyst Replacement Cost	$66,000	5.0	Based on catalyst cost of $7500/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$8,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$88,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$153,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$23,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31. (6th Ed.)
Annual Maintenance Cost	$215,000		Sum of individual Annual Maintenance Costs for SCR and DLN1+.
Total Fixed O&M Cost	$391,000		
Indirect Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$7,000	3%	Sum of individual Annual Maintenance Costs for SCR and DLN1+.
Total Indirect Operating Cost	$7,000		
Total Annual Operating Cost	**$486,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,430,000**		
Annual Operating Cost	**$486,000**		
Total Annual Cost	**$1,916,000**		

SRP - Santan Generating Station
Unit S2 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.040**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.010**
% Reduction w/ SCR	**75%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**9.5%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$10,589,000		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates. Based on SRP (APS) turnkey estimate of $9,081,150 (2010 USD), which includes catalyst placed in middle of evap section, raised piping, tubes, drums, stack by 30 ft. Esclated from 2010 USD to 2016 USD.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$10,589,000		
Direct Installation Costs			
Installation	$1,379,000		Based on SRP cost estimate, includes engineering/design and installation ($1,255,000 2010 USD); Escalated to 2016 USD
Total Direct Capital Costs (DC)	**$11,968,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,394,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$14,362,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,430,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	22	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$9,000	$ 963	Based on ammonia injection rate ammonia reagent cost of $963/ton.
Catalyst Replacement Cost	$66,000	5.0	Based on catalyst cost of $7500/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$7,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$86,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$153,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$23,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31. (6th Ed.)
Annual Maintenance Cost	$215,000		Sum of individual Annual Maintenance Costs for SCR and DLN1+.
Total Fixed O&M Cost	$391,000		
Indirect Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$7,000	3%	Sum of individual Annual Maintenance Costs for SCR and DLN1+.
Total Indirect Operating Cost	$7,000		
Total Annual Operating Cost	**$484,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,430,000**		
Annual Operating Cost	**$484,000**		
Total Annual Cost	**$1,914,000**		

SRP - Santan Generating Station
Unit S3 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.036**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.009**
% Reduction w/ SCR	**75%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**10.1%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$10,589,000		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates. Based on SRP (APS) turnkey estimate of $9,081,150 (2010 USD), which includes catalyst placed in middle of evap section, raised piping, tubes, drums, stack by 30 ft. Esclated from 2010 USD to 2016 USD.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$10,589,000		
Direct Installation Costs			
Installation	$1,379,000		Based on SRP cost estimate, includes engineering/design and installation ($1,255,000 2010 USD); Escalated to 2016 USD
Total Direct Capital Costs (DC)	**$11,968,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,394,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$14,362,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,430,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	21	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$9,000	$ 963	Based on ammonia injection rate ammonia reagent cost of $963/ton.
Catalyst Replacement Cost	$66,000	5.0	Based on catalyst cost of $7500/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$7,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$86,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$153,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$23,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31. (6th Ed.)
Annual Maintenance Cost	$215,000		Sum of individual Annual Maintenance Costs for SCR and DLN1+.
Total Fixed O&M Cost	$391,000		
Indirect Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$7,000	3%	Sum of individual Annual Maintenance Costs for SCR and DLN1+.
Total Indirect Operating Cost	$7,000		
Total Annual Operating Cost	**$484,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,430,000**		
Annual Operating Cost	**$484,000**		
Total Annual Cost	**$1,914,000**		

SRP - Santan Generating Station
Unit S4 - NOx Control Costs
SCR Worksheet

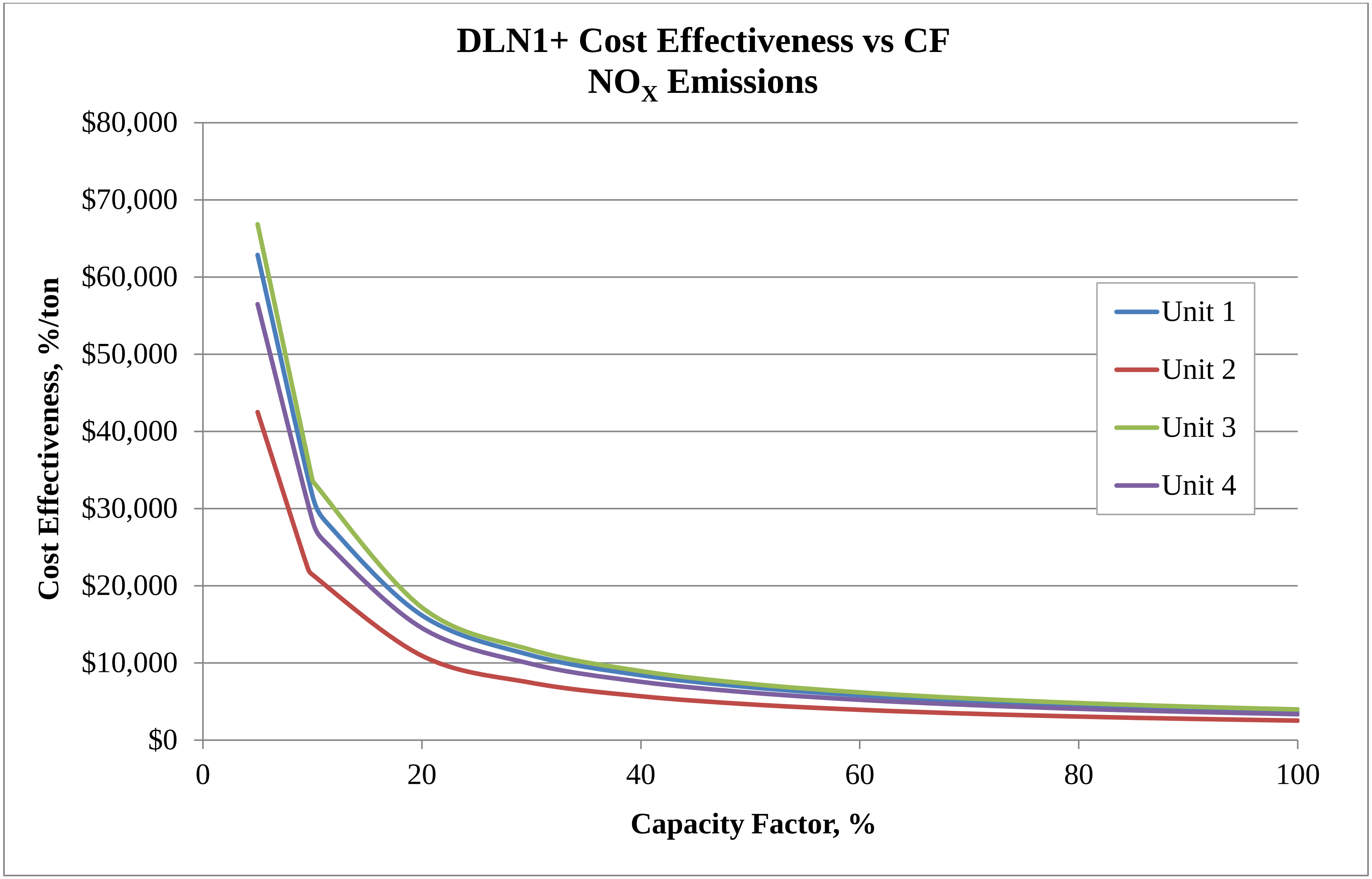
	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.042**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.011**
% Reduction w/ SCR	**75%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**11.0%**

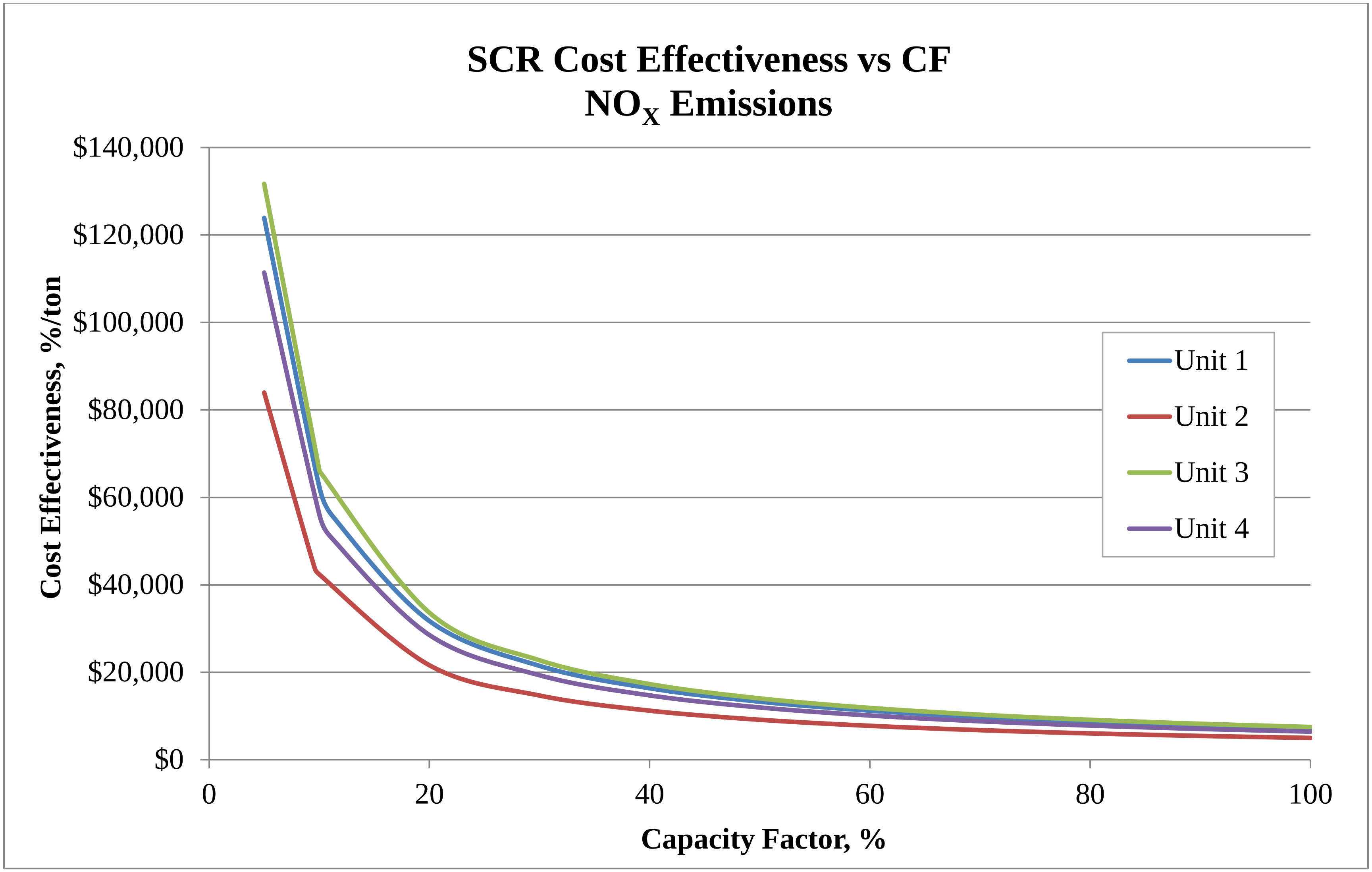
CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$10,589,000		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates. Based on SRP (APS) turnkey estimate of $9,081,150 (2010 USD), which includes catalyst placed in middle of evap section, raised piping, tubes, drums, stack by 30 ft. Esclated from 2010 USD to 2016 USD.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$10,589,000		
Direct Installation Costs			
Installation	$1,379,000		Based on SRP cost estimate, includes engineering/design and installation ($1,255,000 2010 USD); Escalated to 2016 USD
Total Direct Capital Costs (DC)	**$11,968,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,394,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$14,362,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$1,430,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	23	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$11,000	$ 963	Based on ammonia injection rate ammonia reagent cost of $963/ton.
Catalyst Replacement Cost	$66,000	5.0	Based on catalyst cost of $7500/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$8,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$89,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$153,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$23,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31. (6th Ed.)
Annual Maintenance Cost	$215,000		Sum of individual Annual Maintenance Costs for SCR and DLN1+.
Total Fixed O&M Cost	$391,000		
Indirect Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$7,000	3%	Sum of individual Annual Maintenance Costs for SCR and DLN1+.
Total Indirect Operating Cost	$7,000		
Total Annual Operating Cost	**$487,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,430,000**		
Annual Operating Cost	**$487,000**		
Total Annual Cost	**$1,917,000**		

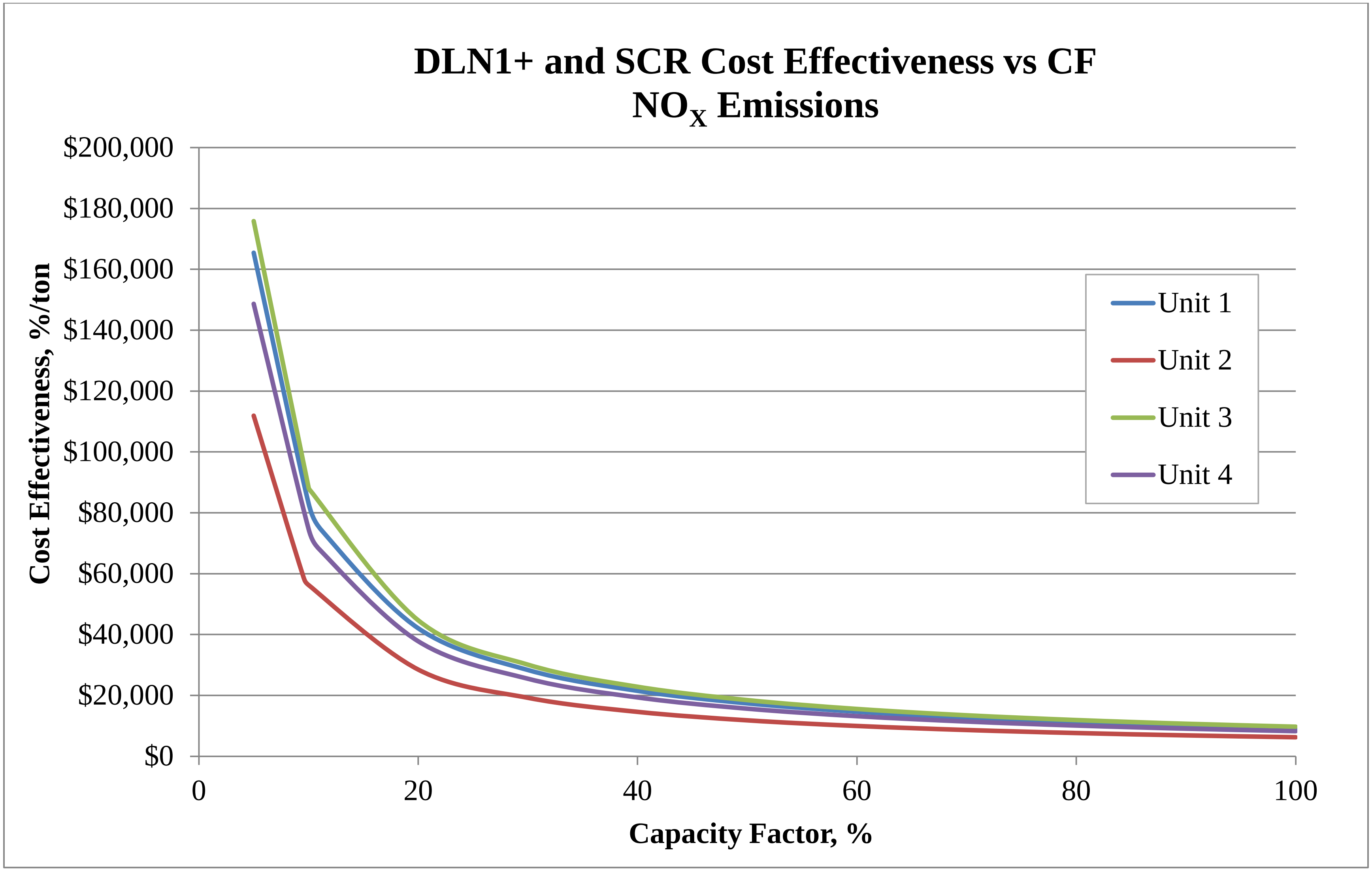
Attachment 7

NO_X Control Cost Sensitivities Versus Capacity Factors

(Units 1 – 4)


DLN1+ Cost Effectiveness vs CF
NOX Emissions
Cost Effectiveness, %/ton
$80,000
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
0
20
40
60
80
100
Capacity Factor, %
Unit 1
Unit 2
Unit 3
Unit 4


SCR Cost Effectiveness vs CF
NOX Emissions
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$0
Cost Effectiveness, %/ton
0
20
40
60
80
100
Capacity Factor, %
Unit 1
Unit 2
Unit 3
Unit 4


DLN1+ and SCR Cost Effectiveness vs CF
NOX Emissions
Cost Effectiveness, %/ton
$200,000
$180,000
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$0
0
20
40
60
80
100
Capacity Factor, %
Unit 1
Unit 2
Unit 3
Unit 4

Attachment 8

Santan Units 1-4 CO Control Cost Summaries

SRP - Santan Generating Station
CO Control Cost Summary -- Units 1-4

Unit S1 - CO Control Costs

Net Generation	90	MW
Net Generation	39420	MWh
Capacity Factor:	5.00%	
Net Heat Rate	8,624	Btu/kWh
Actual Annual Heat Input:	339,958	MMBtu/yr
Actual Annual Fuel Consumption:	333	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline - Existing DLN1 Combustors and CO Catalyst System	15.1	0.015	2.5		
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	13.6	0.013	2.3	10%	0.3
CO Catalyst System Upgrades and Combustor Upgrades	7.6	0.007	1.3	50%	1.3
CO Catalyst System Upgrades with Existing DLN1 Combustors	7.6	0.007	1.3	50%	1.3

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline - Existing DLN1 Combustors and CO Catalyst System	2.5								
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	2.3	0.3	$5,844,000	$582,000	$65,000	$647,000	**$2,570,774**		
CO Catalyst System Upgrades and Combustor Upgrades	1.3	1.3	$6,184,200	$616,000	$111,000	$727,000	**$577,729**	1.0	$79,468
CO Catalyst System Upgrades with Existing DLN1 Combustors	1.3	1.3	$340,200	$34,000	$46,000	$80,000	**$63,574**	1.0	NA

Unit S2 - CO Control Costs

Net Generation	90	MW
Net Generation	39420	MWh
Capacity Factor:	5.00%	
Net Heat Rate	9,470	Btu/kWh
Actual Annual Heat Input:	373,307	MMBtu/yr
Actual Annual Fuel Consumption:	366	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline - Existing DLN1 Combustors and CO Catalyst System	44.8	0.044	8.2		
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	40.3	0.040	7.4	10%	0.8
CO Catalyst System Upgrades and Combustor Upgrades	22.4	0.022	4.1	50%	4.1
CO Catalyst System Upgrades with Existing DLN1 Combustors	22.4	0.022	4.1	50%	4.1

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline - Existing DLN1 Combustors and CO Catalyst System	8.2								
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	7.4	0.8	$5,844,000	$582,000	$71,000	$653,000	**$796,975**		
CO Catalyst System Upgrades and Combustor Upgrades	4.1	4.1	$6,184,200	$616,000	$117,000	$733,000	**$178,923**	3.3	$24,410
CO Catalyst System Upgrades with Existing DLN1 Combustors	4.1	4.1	$340,200	$34,000	$46,000	$80,000	**$19,528**	3.3	NA

Unit S3 - CO Control Costs

Net Generation	90	MW
Net Generation	39420	MWh
Capacity Factor:	5.00%	
Net Heat Rate	9,412	Btu/kWh
Actual Annual Heat Input:	371,021	MMBtu/yr
Actual Annual Fuel Consumption:	364	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline - Existing DLN1 Combustors and CO Catalyst System	10.6	0.010	1.9		
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	9.6	0.009	1.7	10%	0.2
CO Catalyst System Upgrades and Combustor Upgrades	5.3	0.005	1.0	50%	1.0
CO Catalyst System Upgrades with Existing DLN1 Combustors	5.3	0.005	1.0	50%	1.0

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline - Existing DLN1 Combustors and CO Catalyst System	1.9								
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	1.7	0.2	$5,844,000	$582,000	$71,000	$653,000	**$3,381,979**		
CO Catalyst System Upgrades and Combustor Upgrades	1.0	1.0	$6,184,200	$616,000	$117,000	$733,000	**$759,262**	0.8	$103,583
CO Catalyst System Upgrades with Existing DLN1 Combustors	1.0	1.0	$340,200	$34,000	$46,000	$80,000	**$82,866**	0.8	NA

Unit S4 - CO Control Costs

Net Generation	90	MW
Net Generation	39420	MWh
Capacity Factor:	5.00%	
Net Heat Rate	9,285	Btu/kWh
Actual Annual Heat Input:	366,015	MMBtu/yr
Actual Annual Fuel Consumption:	359	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline - Existing DLN1 Combustors and CO Catalyst System	37.8	0.037	6.8		
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	34.0	0.033	6.1	10%	0.7
CO Catalyst System Upgrades and Combustor Upgrades	18.9	0.019	3.4	50%	3.4
CO Catalyst System Upgrades with Existing DLN1 Combustors	18.9	0.019	3.4	50%	3.4

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline - Existing DLN1 Combustors and CO Catalyst System	6.8								
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	6.1	0.7	$5,844,000	$582,000	$72,000	$654,000	**$963,671**		
CO Catalyst System Upgrades and Combustor Upgrades	3.4	3.4	$6,184,200	$616,000	$118,000	$734,000	**$216,310**	2.7	$29,470
CO Catalyst System Upgrades with Existing DLN1 Combustors	3.4	3.4	$340,200	$34,000	$46,000	$80,000	**$23,576**	2.7	NA

SRP - Santan Generating Station
Units S1-S4 -- CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.096**
Post DLN1+ NOx Emission Rate	**0.038**
% NOx Reduction w/ DLN1+	**60%**
Baseline CO Emission Rate (lb/mmBtu)	**0.015**
Post DLN1+ CO Emission Rate	**0.013**
% CO Reduction w/ DLN1+	**10.0%**
Capacity Factor used for Cost Estimates (%)	**5.0%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
CO Control Equipment	**$2,938,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor; $2.9M for first Unit; $2.8M for each unit after; average $2,825,000 (2013 USD); Escalated to 2016 USD using Handy Whitman Escalation Rates
Total Purchased Equipment Cost (PEC)	$2,938,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,811,000		Based on SRP DLN1 Installation Costs : $4,896,000 for all units in 2000 USD; escalated to 2016 USD using Handy Whitman Escalation Rates
Total Direct Capital Costs (DC)	**$4,749,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$67,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Controls Engineering/Design	$36,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Training	$13,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Field Services	$5,000		Based on SRP DLN1 Installation Costs (adjusted to 2016 dollars)
Total Indirect Capital Costs (IC)	**$121,000**		
Contingency	$974,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$5,844,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$582,000**	7.70%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$7,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$7,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Annual Maintenance Cost	$58,000	1.0%	Maintenance cost estimated based on replacement of combustor parts. Estimated 1%.
Total Fixed O&M Cost	$58,000		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$65,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$582,000**		
Annual Operating Cost	**$65,000**		
Total Annual Cost	**$647,000**		

SRP - Santan Generating Station
Unit S1 -- CO Control Costs
Oxidation Catalyst Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline CO Emission Rate (lb/mmBtu)	**0.015**
Post CO Catalyst Emission Rate (lb/mmBtu)	**0.007**
% Reduction w/ CO Catalyst Upgrades	**50%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**5.0%**

CAPITAL COSTS	[$]		Basis
Direct Capital Costs			
Control Equipment	$185,000		Based on budgetary costs for oxidation catalyst system upgrades (Johnson Matthey). Includes costs for catalyst replacement and new internal frame.
Instrumentation	$0		Included in CO control equipment cost
Sales Taxes	$0		Included in CO control equipment cost
Freight	$0		Included in CO control equipment cost
Total Purchased Equipment Cost	$185,000		
Direct Installation Costs			
Installation	$55,500	30%	Engineering estimate: 30% of PEC
Total Direct Capital Costs (DC)	**$240,500**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
General Facilities	$9,300	5%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors for an SCR system (Section 4, Chapter 2, 6th Ed.), and assuming that the same factors would apply for an Oxidation Catalyst System
Engineering and Home Office Fees	$18,500	10%	
Process Contingency	$9,300	5%	
Startup and Performance Tests	$5,600	3%	
Total Indirect Capital Costs (IC)	**$42,700**		
Contingency	$57,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$340,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$34,000**	7.70%	pretax marginal rate of return on private investment
OPERATING & MAINTENANCE COSTS			**Basis**
Variable O&M Costs			
Reagent Cost	$0		NA
Catalyst Volume	323	90,847	Catalyst Volume (in ft^3) calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Catalyst Replacement Cost	$37,000	5.0	Based on the total cost of the catalyst replaced every 5 years. ($153,000/5)
Auxiliary Power Cost	$4,000	2	Based on the increased pressure drop across the CO catalyst (listed to the left in inches), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$41,000		
Fixed O&M Costs			
Additional Operators per shift	0.0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervision	$0		
Annual Maintenance Cost	$5,000		Maintenance costs based on testing catalyst coupons. Approx. $5000/yr
Total Direct Annual Costs	$5,000		
Indirect Annual Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating & Maintenance Cost	**$46,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$34,000**		
Annual Operating & Maintenance Cost	**$46,000**		
Total Annual Cost	**$80,000**		

SRP - Santan Generating Station
Unit S2 -- CO Control Costs
Oxidation Catalyst Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	950.0
Approximate MW output	90.0
Baseline CO Emission Rate (lb/mmBtu)	0.044
Post CO Catalyst Emission Rate (lb/mmBtu)	0.022
% Reduction w/ CO Catalyst Upgrades	50%
Stack Flue Gas Flow Rate (scfm)	489,060
Capacity Factor used for Cost Estimates (%)	5.0%

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
Control Equipment	$185,000		Based on budgetary costs for oxidation catalyst system upgrades (Johnson Matthey). Includes costs for catalyst replacement and new internal frame.
Instrumentation	$0	0%	Included in CO control equipment cost
Sales Taxes	$0	0%	Included in CO control equipment cost
Freight	$0	0%	Included in CO control equipment cost
Total Purchased Equipment Cost	$185,000		
Direct Installation Costs			
Installation	$55,500	30%	Engineering estimate 30% of PEC
Total Direct Capital Costs (DC)	**$240,500**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
General Facilities	$9,300	5%	
Engineering and Home Office Fees	$18,500	10%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors for an SCR system (Section 4, Chapter 2), and assuming that the same factors would apply for an Oxidation Catalyst System
Process Contingency	$9,300	5%	
Startup and Performance Tests	$5,600	3%	
Total Indirect Capital Costs (IC)	**$42,700**		
Contingency	$57,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$340,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$34,000**	7.70%	pretax marginal rate of return on private investment
OPERATING & MAINTENANCE COSTS			**Basis**
Variable O&M Costs			
Reagent Cost	$0		NA
Catalyst Volume	323	90,847	Catalyst Volume (in ft^3) calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Catalyst Replacement Cost	$37,000	5.0	Based on the total cost of the catalyst replaced every 5 years. ($153,000/5)
Auxiliary Power Cost	$4,000	2	Based on the increased pressure drop across the CO catalyst (listed to the left in inches), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$41,000		
Fixed O&M Costs			
Additional Operators per shift	0.0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervision	$0		
Annual Maintenance Cost	$5,000		Maintenance costs based on testing catalyst coupons. Approx. $5000/yr
Total Direct Annual Costs	$5,000		
Indirect Annual Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating & Maintenance Cost	**$46,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$34,000**		
Annual Operating & Maintenance Cost	**$46,000**		
Total Annual Cost	**$80,000**		

SRP - Santan Generating Station
Unit S3 -- CO Control Costs
Oxidation Catalyst Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline CO Emission Rate (lb/mmBtu)	**0.010**
Post CO Catalyst Emission Rate (lb/mmBtu)	**0.005**
% Reduction w/ CO Catalyst Upgrades	**50%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**5.0%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
Control Equipment	$185,000		Based on budgetary costs for oxidation catalyst system upgrades (Johnson Matthey). Includes costs for catalyst replacement and new internal frame.
Instrumentation	$0	0%	Included in CO control equipment cost
Sales Taxes	$0	0%	Included in CO control equipment cost
Freight	$0	0%	Included in CO control equipment cost
Total Purchased Equipment Cost	$185,000		
Direct Installation Costs			
Installation	$55,500	30%	Engineering estimate 30% of PEC
Total Direct Capital Costs (DC)	**$240,500**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
General Facilities	$9,300	5%	
Engineering and Home Office Fees	$18,500	10%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors for an SCR system (Section 4, Chapter 2), and assuming that the same factors would apply for an Oxidation Catalyst System
Process Contingency	$9,300	5%	
Startup and Performance Tests	$5,600	3%	
Total Indirect Capital Costs (IC)	**$42,700**		
Contingency	$57,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$340,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$34,000**	7.70%	pretax marginal rate of return on private investment
OPERATING & MAINTENANCE COSTS			**Basis**
Variable O&M Costs			
Reagent Cost	$0		NA
Catalyst Volume	323	90,847	Catalyst Volume (in ft^3) calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Catalyst Replacement Cost	$37,000	5.0	Based on the total cost of the catalyst replaced every 5 years. ($153,000/5)
Auxiliary Power Cost	$4,000	2	Based on the increased pressure drop across the CO catalyst (listed to the left in inches), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$41,000		
Fixed O&M Costs			
Additional Operators per shift	0.0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervision	$0		
Maintenance Labor and Materials	$5,000		Maintenance costs based on testing catalyst coupons. Approx. $5000/yr
Total Direct Annual Costs	$5,000		
Indirect Annual Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating & Maintenance Cost	**$46,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$34,000**		
Annual Operating & Maintenance Cost	**$46,000**		
Total Annual Cost	**$80,000**		

SRP - Santan Generating Station
Unit S4 -- CO Control Costs
Oxidation Catalyst Worksheet

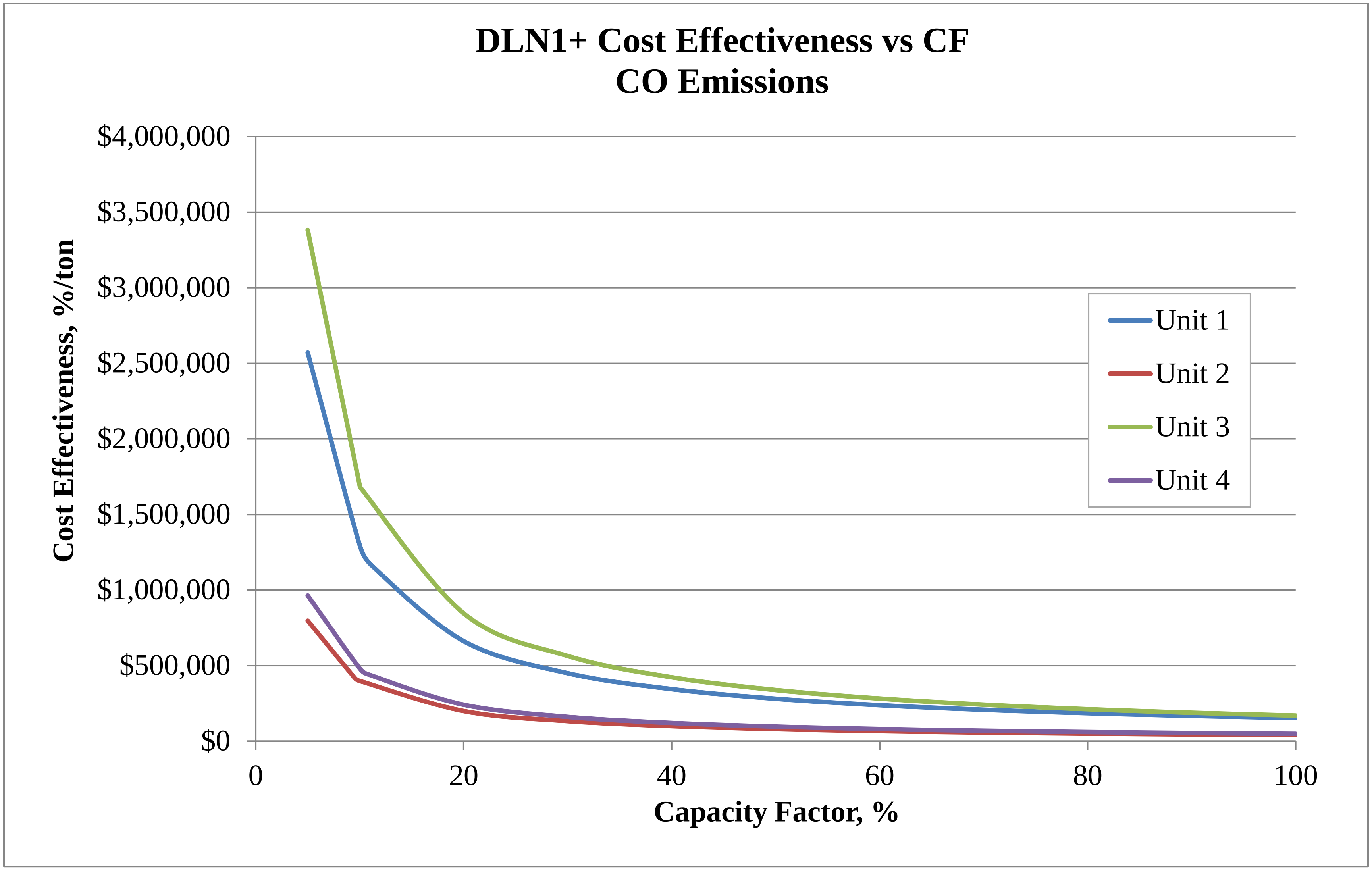
	INPUT
CT Heat Input (mmBtu/hr)	**950.0**
Approximate MW output	**90.0**
Baseline CO Emission Rate (lb/mmBtu)	**0.037**
Post CO Catalyst Emission Rate (lb/mmBtu)	**0.019**
% Reduction w/ CO Catalyst Upgrades	**50%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**5.0%**

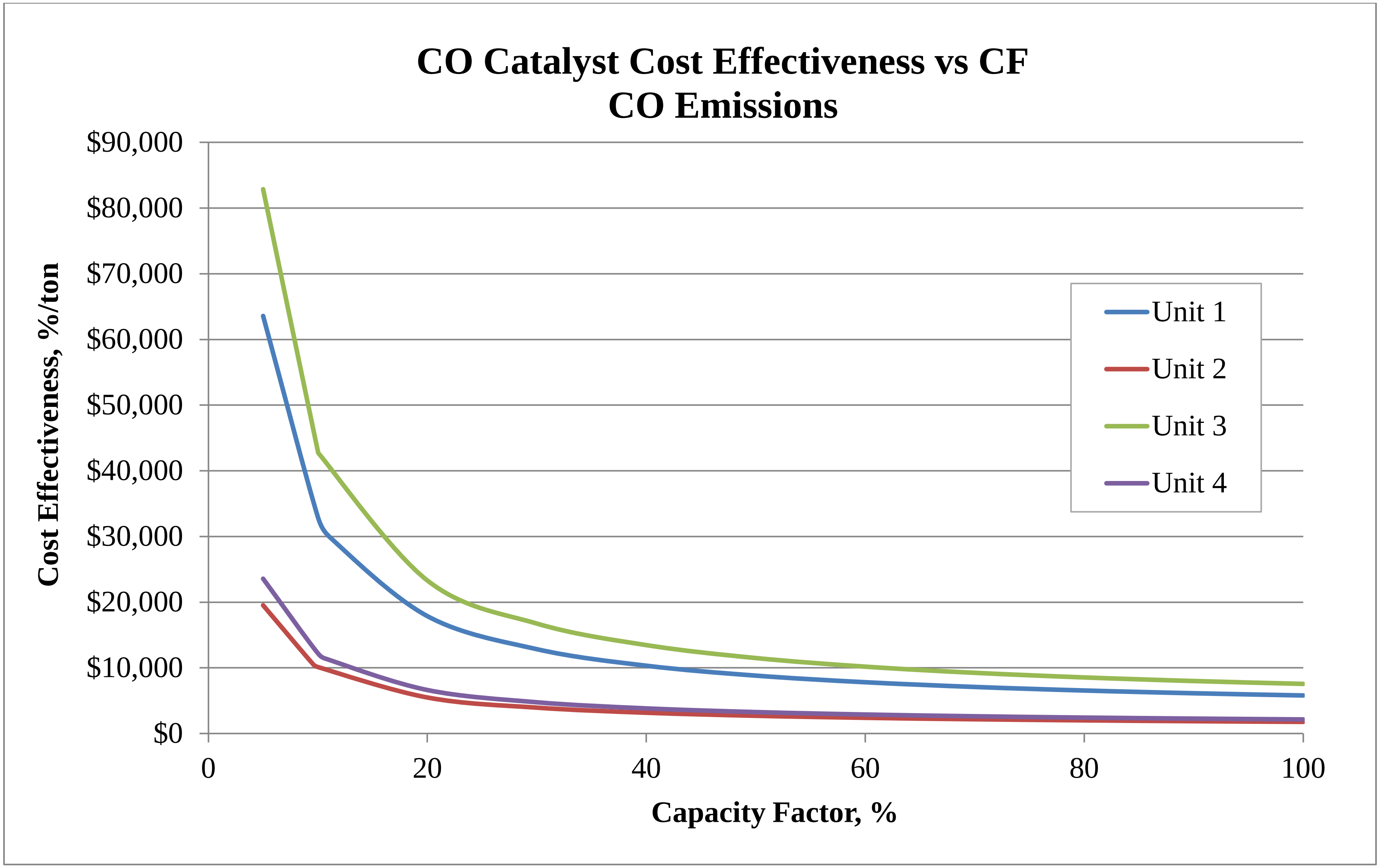
CAPITAL COSTS	[$]		Basis
Direct Capital Costs			
Control Equipment	$185,000		Based on budgetary costs for oxidation catalyst system upgrades (Johnson Matthey). Includes costs for catalyst replacement and new internal frame.
Instrumentation	$0	0%	Included in CO control equipment cost
Sales Taxes	$0	0%	Included in CO control equipment cost
Freight	$0	0%	Included in CO control equipment cost
Total Purchased Equipment Cost	$185,000		
Direct Installation Costs			
Installation	$55,500	30%	Engineering estimate 30% of PEC
Total Direct Capital Costs (DC)	**$240,500**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
General Facilities	$9,300	5%	
Engineering and Home Office Fees	$18,500	10%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors for an SCR system (Section 4, Chapter 2), and assuming that the same factors would apply for an Oxidation Catalyst System
Process Contingency	$9,300	5%	
Startup and Performance Tests	$5,600	3%	
Total Indirect Capital Costs (IC)	**$42,700**		
Contingency	$57,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$340,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0996	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$34,000**	7.70%	pretax marginal rate of return on private investment
OPERATING & MAINTENANCE COSTS			**Basis**
Variable O&M Costs			
Reagent Cost	$0		NA
Catalyst Volume	323	90,847	Catalyst Volume (in ft^3) calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Catalyst Replacement Cost	$37,000	5.0	Based on the total cost of the catalyst replaced every 5 years. ($153,000/5)
Auxiliary Power Cost	$4,000	2	Based on the increased pressure drop across the CO catalyst (listed to the left in inches), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$41,000		
Fixed O&M Costs			
Additional Operators per shift	0.0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervision	$0		
Annual Maintenance Cost	$5,000		Maintenance costs based on testing catalyst coupons. Approx. $5000/yr
Total Direct Annual Costs	$5,000		
Indirect Annual Operating Cost			
Property Taxes	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Insurance	$0	0%	Zero based on EPA Cost Manual (7th ed.) Ch. 2, p. 2-78.
Administration	$0	0%	Administration costs for combustors using Eq. 2.68 and Eq. 2.69 yielded less than $1,000. Assumed to be neglible. EPA Cost Manual (7th Ed.) Ch. 2, p. 2-78.
Total Indirect Operating Cost	$0		
Total Annual Operating & Maintenance Cost	**$46,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$34,000**		
Annual Operating & Maintenance Cost	**$46,000**		
Total Annual Cost	**$80,000**		

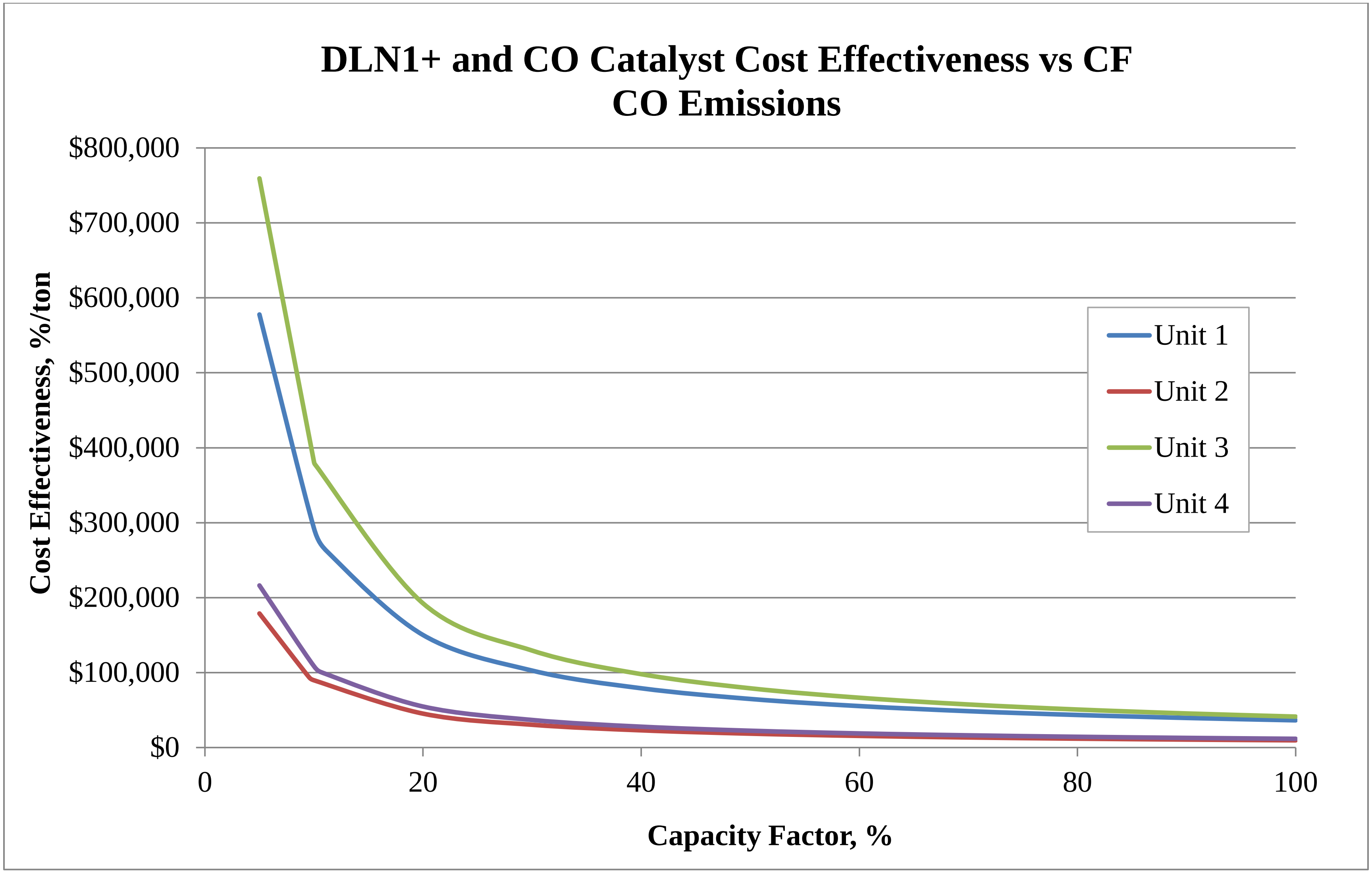
Attachment 9

CO Control Cost Sensitivities Versus Capacity Factors

(Units 1 – 4)


DLN1+ Cost Effectiveness vs CF
CO Emissions
Cost Effectiveness, %/ton
$4,000,000
$3,500,000
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
0
20
40
60
80
100
Capacity Factor, %
Unit 1
Unit 2
Unit 3
Unit 4


CO Catalyst Cost Effectiveness vs CF
CO Emissions
$90,000
$80,000
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
Cost Effectiveness, %/ton
0
20
40
60
80
100
Capacity Factor, %
Unit 1
Unit 2
Unit 3
Unit 4


DLN1+ and CO Catalyst Cost Effectiveness vs CF
CO Emissions
Cost Effectiveness, %/ton
$800,000
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$0
0
20
40
60
80
100
Capacity Factor, %
Unit 1
Unit 2
Unit 3
Unit 4

Attachment 10

Summary Table of Reference Cost Thresholds

Sample of Cost Effectiveness Determinations for NOx and CO Controls

		NOx Control Cost Effectiveness			CO Control Cost Effectiveness				
State	**Facility**	**NOx Control Technology Evaluated**	**Cost Effectiveness Value**	**Cost Effective?**	**CO Control Technology Evaluated**	**Cost Effectiveness Value**	**Cost Effective?**	**Notes**	**Reference[(1)]**
NY	NA	NA	< $3,000/ton	Yes	---	---	---	NYSDEC RACT NOX cost effectiveness threshold	1
SD	Hyperion Energy Center	NA	< $10,000 - $15,000/ton	Yes	---	---	---	Memo from RTP to Hyperion states "incremental cost effectiveness threshold for NOx BACT is generally perceived to be $10,000 to $15,000 per ton."	2
VA	Commonwealth Chesapeake Power Station	SCR	$1,452/ton $12,354/ton (incremental)	@ $1,452/ton -- Yes @ $12,354/ton -- No	---	---	---		3
KS	Emporia Energy Center	SCR	> $5,000/ton (incremental)	No	---	---	---	In response to EPA comments to Draft PSD Permit, Westar stated "Historically, KDHE has considered NOx BACT add-on emission controls to be cost prohibitive when the incremental removal costs exceed $5,000."	4
		SCR	$5,200/ton	Yes	---	---	---	In comments to Draft PSD Permit, EPA stated that $5,200/ton is "well within the range that many agencies have considered reasonable for installation of SCR."	4
KY	East Kentucky Power Cooperative, J.K. Smith Generating Station	SCR	< $3,330 - $5,138/ton	Yes	---	---	---	KY DEP's statement of basis states that this cost effectiveness range "is consistent with EPA's Air Pollution Control Technology Gact Sheet on SCR"	5
		SCR	$6,583/ton	No	---	---	---	Based on 4,000 hr/yr, EKPC calculated a cost effectiveness value of $6,583/ton. KY DEP stated "EKPC's cost analysis is consistent with RBLC data nad demonstrates that higher levels of control are not cost-effective at 4000 hours of operation per year or lower.	5
AL	Tenaska Alabama IV Partners	SCONOx	$6,145/ton	No	Oxidation Catalyst	$1,506/ton	No		6
AL	Duke Energy Autauga, LLC	SCONOx	$18760/ton	No	Oxidation Catalyst	$5,006/ton	No		6
AL	Duke Energy Dale, LLC	SCONOx	$18,403/ton	No	Oxidation Catalyst	$2,634/ton CO+VOC	No		6
FL	Hines Energy (FPC)	SCONOx	$16,712/ton	No	Oxidation Catalyst	$2,130/ton	No		6
FL	CPV - Gulfcoast	---	---	---	Oxidation Catalyst	$4,350/ton	No		6
FL	Duke Energy - Ft. Pierce	SCR	$50,602/ton	No	Oxidation Catalyst	$21,832/ton CO&VOC	No		6
FL	Pompano Beach Energy Center, LLC	SCR	$20,400/ton	No	Oxidation Catalyst	$31,800/ton	No		6

Sample of Cost Effectiveness Determinations for NOx and CO Controls

		NOx Control Cost Effectiveness			CO Control Cost Effectiveness				
State	**Facility**	**NOx Control Technology Evaluated**	**Cost Effectiveness Value**	**Cost Effective?**	**CO Control Technology Evaluated**	**Cost Effectiveness Value**	**Cost Effective?**	**Notes**	**Reference[1]**
FL	Midway Development Center	SCR	$20,700/ton	No	Oxidation Catalyst	$31,800/ton	No		6
FL	Duke Energy Lake	SCR	$15,000/ton	No	Oxidation Catalyst	$5,563/ton	No		6
FL	Calpine Blue Heron Energy Center	SCONOx	$9,982/ton	No	Oxidation Catalyst	$1,553/ton	No		6
GA	Duke Energy Sandersville, LLC	SCR	$36,520/ton	No	Oxidation Catalyst	$8,330/ton	No		6
GA	Augusta Energy LLC	SCR	$17,490/ton	No	Oxidation Catalyst	$1,828/ton	Yes		6
GA	Oglethorpe Power Corp. - Talbot	SCR	$9,381/ton	No	Oxidation Catalyst	$3,980/ton	No		6
GA	MEA of Georgia - W. R. Clayton	SCR	$14,100/ton	No	Oxidation Catalyst	$15,000/ton	No		6
KY	East Kentucky Power Cooperative, Inc.	--	--	--	Oxidation Catalyst	$8,000/ton	No		6
MS	MEP Clarksdale Power	SCR	$26,567/ton	No	Oxidation Catalyst	$5,593/ton	No		6
MS	TVA - Kemper CT Plant	SCR	$13,668/ton	No	Oxidation Catalyst	$8,036/ton	No		6
MS	Reliant Energy - Choctaw Co., LLC	SCONOx	$48,663/ton	No	Oxidation Catalyst	$3,550/ton	No		6
MS	Crossroads Energy Center	SCONOx	$23,400/ton	No	Oxidation Catalyst	$11,039/ton	No		6
MS	South Mississippi Electric Power Association - Moselle	SCR	$9,973/ton	No	Oxidation Catalyst	$2,417/ton	No		6
NC	Duke Energy - Buck Steam Station	--	--	--	Oxidation Catalyst	$11,976/ton	No		6
NC	Entergy Power - Rowan Generating Facility	SCR	$13,049/ton	No	Oxidation Catalyst	$8,204/ton	No		6
NC	GenPower Earleys, LLC	SCONOx	$21,942/ton	No	Oxidation Catalyst	$3,246ton	No		6
NC	Mountain Creek - Granville Energy Center	SCONOx	$22,600/ton	No	Oxidation Catalyst	$3,560ton	No		6
SC	Columbia Energy	--	--	--	Oxidation Catalyst	$1,611/ton	No		6
SC	Greenville Generating	SCR	$13,909/ton	No	Oxidation Catalyst	$8,204/ton	No		6
SC	Greenville Power Project	SCONOx	$18,300/ton	No	Oxidation Catalyst	$5,800/ton	No		6
SC	Jasper County Generating Facility	SCONOx	$19,870/ton	No	Oxidation Catalyst	$3,320/ton	No		6
SC	Cherokee Falls Combined-Cycle Facility	SCONOx	$22,434/ton	No	Oxidation Catalyst	$2,500/ton	No		6
SC	Broad River Energy Center (f/k/a Cherokee Falls)	SCR	$22,800/ton	No	Oxidation Catalyst	$10,500/ton	No		6
SC	Palmetto Energy Center	SCONOx	$18,789/ton	No	Oxidation Catalyst	$2,111/ton	No		6
SC	Santee Cooper Rainey Generating Station	SCR	$15,550/ton	No	Oxidation Catalyst	$1,717/ton	No		6

Sample of Cost Effectiveness Determinations for NOx and CO Controls

		NOx Control Cost Effectiveness			CO Control Cost Effectiveness				
State	**Facility**	**NOx Control Technology Evaluated**	**Cost Effectiveness Value**	**Cost Effective?**	**CO Control Technology Evaluated**	**Cost Effectiveness Value**	**Cost Effective?**	**Notes**	**Reference[1]**
TN	TVA, Lagoon Creek Plant	SCR	$2,060/ton	Yes	Oxidation Catalyst	$2,873/ton	Yes		6
IL	Peoples Gas, McDonnell Energy	--	--	--	Oxidation Catalyst	$3043/ton	No		6
IL	Reliant Energy (Houston Industries), Cardinal Woods Rivery Refinery	--	--	--	Oxidation Catalyst	$1993/ton	No		6
IL	Mid America, Cordova Energy Center	--	--	--	Oxidation Catalyst	$1307/ton	No		6
IL	Enron, Des Plaines Green Land	--	--	--	Oxidation Catalyst	$6800/ton	No		6
IL	Enron, Kendall New Century	--	--	--	Oxidation Catalyst	$6700/ton	No		6
IL	LS Power, Nelson Project	--	--	--	Oxidation Catalyst	$3100/ton	No		6
IL	Ameren CIPS	--	--	--	Oxidation Catalyst	$3400/ton	No		6
IL	Holland Energy	SCR	$8,900/ton	Yes	Oxidation Catalyst	$10,600/ton	No		6
IL	Duke Energy - Lee Generating	SCR	$27,689/ton	No	Oxidation Catalyst	$6,931/ton	No		6
IN	Duke Energy Vermillion Generating Station	SCR	$19,309/ton	No	Oxidation Catalyst	$8,977/ton	No		6
MI	Wyandotte Energy	SCR	$5600/ton	Yes	--	--	--		6
MN	Lakefield Junction	SCR	$11,500/ton	No	Oxidation Catalyst	$3000/ton	No		6
OH	Duke Energy Madison LLC	SCR	$19,000/ton	No	Oxidation Catalyst	$9000/ton	No		6
OH	Duke Energy - Hanging Rock, LLC	--	--	--	Oxidation Catalyst	$3,490/ton	No		6
OH	University of Cincinnati	SCR	$11,834/ton	No	--	--	--		6
WI	RockGen Energy	SCR	$23,018/ton	No	Oxidation Catalyst	$15,000/ton	No		6
WI	Southern Energy	--	--	--	Oxidation Catalyst	$14,000/ton	No		6
WI	Wisconsin Public Service	SCR	$13,866/ton	No	Oxidation Catalyst	$6053/ton incremental cost	No		6
WI	Wisconsin Electric	SCR	$10,257/ton	No	Oxidation Catalyst	$5984/ton incremental cost	No		6
OK	AECI-Chouteau	SCR	$2,535/ton	Yes	--	--	--		6
MO	AECI - St. Francis Unit 2	SCR	$1,165/ton	Yes	--	--	--		6
MO	Utilicorp - Aquila Merchant, Pleasant Hill	SCR	$2,500/ton	Yes	--	--	--		6
AZ	Griffith Energy, LLC	SCR	$1,555/ton	Yes	--	--	--		6

Sample of Cost Effectiveness Determinations for NOx and CO Controls

		NOx Control Cost Effectiveness			CO Control Cost Effectiveness				
State	**Facility**	**NOx Control Technology Evaluated**	**Cost Effectiveness Value**	**Cost Effective?**	**CO Control Technology Evaluated**	**Cost Effectiveness Value**	**Cost Effective?**	**Notes**	**Reference(1)**
MT	Basin Electric Power Cooperative, Culbertson Generating Station	SCR	$31,000/ton (incremental)	No	Oxidation Catalyst	$5,300/ton	Yes		7
NA	NA	SCR	$3,000 - $6,000/ton	NA	---	---	---	EPA's estimated costs for SCR on large combustion turbines	8
FL	Florida Power & Light Co., Turkey Point Fossil Plant Unit 5	SCR	$3,753/ton (incremental)	Yes	Oxidation Catalyst	$4,240/ton	No		9
FL	Florida Power & Light Co., Turkey Point Fossil Plant	---	---	---	Oxidation Catalyst	$8,000/ton	No		10
FL	Florida Power & Light Co., West County Energy Center	SCR	$3,602/ton (incremental)	Yes	Oxidation Catalyst	$8,667/ton	No		10
		SCONOx	$11,447/ton (incremental)	No	SCONOx	$63,000/ton (incremental)	No		10
AZ	Apache Generating Station	SCR	$20,554/ton	No	---	---	---		12
GA	Dahlberg Combustion Turbine Electric Generating Plant	SCR	$20,554/ton	No	Oxidation Catalyst	$20,881	No		13
WV	Pleasants Energy Facility	SCR	$22,992/ton	No	Oxidation Catalyst	$17,805	No	Air Construction Permit prepared to increase operating time of existing combustion turbines.	14
CA	Oakley Generating Station	---	---	---	Oxidation Catalyst	$4,338	No		15
IN	Midwest Fertilizer Corporation	SCR	$23,145/ton	No	Oxidation Catalyst	$388,644	No		16
FL	Lauderdale	SCR	> $20,000 (incremental)	No	Oxidation Catalyst	> $10,000	No	Preliminary Determination - Feb. 27, 2014	17

Sample of Cost Effectiveness Determinations for NOx and CO Controls

		NOx Control Cost Effectiveness			CO Control Cost Effectiveness				
State	**Facility**	**NOx Control Technology Evaluated**	**Cost Effectiviness Value**	**Cost Effective?**	**CO Control Technology Evaluated**	**Cost Effectiviness Value**	**Cost Effective?**	**Notes**	**Reference[1]**
TX	Corpus Christi Liquefaction LLC	SCR	$22,500/ton	No	---	---	---		18
PA	NA	NA	<$3,500/ton	Yes	---	---	---	Pennsylvania Environmental Quality Board cost effectiveness threshold	19
WI	NA	NA	<$2,500/ton	Yes	---	---	---	Wisconsin NOx RACT cost effectiveness threshold.	20
CA	NA	NA	< $9,700/ton	Yes	NA	< $300/ton	Yes	Cost Effective Thresholds developed for San Joaquin Valley.	21

Sample of Cost Effectiveness Determinations for NOx and CO Controls

(1) References:

1. New York State Department of Environmental Conservation, "Air Guide 20 Economic and Technical Analysis for Reasonably Available Control Technology."
2. Memorandum from Colin Campbell (RTP Environmental Associates) to Corey Frank (Hyperion Resources), “Targets for
3. Application for Stock Island Power Plant Combustion Turbine Unit 4, October 2004.
4. Comments on Draft PSD Permit for Emporia Energy Center,” April 13, 2007.
5. Quality, “Revised Statement of Basis, Title V Draft Permit, No. V-05-070 R2, East Kentucky Power Cooperative, Inc.
6. United States Environmental Protection Agency Region 4, “National Combustion Turbine Spreadsheet,” March 30, 2005.
7. Montana Department of Environmental Quality Permitting and Compliance Division, “Air Quality Permit #4256-00, Basin
8. United States Environmental Protection Agency, Air Pollution Control Technology Fact Sheet – Selective Catalytic Reduction, EPA-452/F-03-032.
9. Florida Power & Light Company, PSD Permit Application for the Turkey Point Fossil Plant Unit 5, November 4, 2003.
10. Florida Department of Environmental Protection, “Technical Evaluation and Preliminary Determination, Florida Power &
11. Florida Power & Light Company, PSD Permit Application for the West County Energy Center, November 2007.
12. National Park Service (NPS) Comments to "Arizona Electric Power Cooperative (AEPC) - Apache Generating Station BART Analysis and Determination," November 29, 2010.
13. State of Georgia, Department of Natural Resource,s Environmental Protection Division, Air Protection Branch "Prevention
14. Pleasants Energy, LLC, PSD Air Construction Permit Application for Pleasants Energy Facility to increase operating time of existing combustion turbines, September 2015.
15. Bay Area Air Quality Management District, Final Determination of Compliance for Oakley Generating Station, Application 20798, January 2011.
16. Indiana Department of Environmental Management, Approval of "PSD/New Source Construction and Part 70 Operating Permit," June 4, 2014.
17. Florida Power & Light Company, Technical Evaluation & Preliminary Determination for Lauderdale Plant, February 27, 2014.
18. Response from Executive Director of Texas Commission on Environmental Quality to Public Comment on the Application by Corpus Christi Liquefaction LLC
19. Pennsylvania Environmental Quality Board - Title 25 PA. Code CHS. 121 and 129 "Additional RACT Requirements for Major Sources of NO_X and VOCs," April 23, 2016.
20. Natural Resources Board Agenda Item "Order AM-17-05, authorization for hearing on creation of NR 428.20 to 428.27
21. San Joaquin Valley Unified Air Pollution Control Distric. Best Available Control Technology (BACT) Policy. November 9, 1999.