ATTACHMENT 1

NO_X TECHNOLOGICAL FEASIBILITY AND COST-EFFECTIVENESS ANALYSIS

The Bay Area Air Quality Management District (BAAQMD) has asked Contra Costa Generating Station, LLC (CCGS) to consider the cost effectiveness of a NO_X control limitation of 1.5 ppm (1-hour average). This cost effectiveness request is in response to the BAAQMD requirements to consider “any emission control device or technique determined to be technologically feasible and cost effective, but not achieved in practice.” The following cost analysis is based on the EPA “top-down” BACT cost estimation methodology for NO_X and has been prepared in accordance with EPA’s 1990 Draft New Source Review Workshop Manual. The baseline NO_X emission rate for this analysis is considered to be 9 ppmvd @ 15% O2 (ppm), based on the inherent NO_X control design (dry low-NO_X combustors). This emission rate also provides the frame of reference for the evaluation of control effectiveness and feasibility based on the cost of each ton of NO_X removed. The maximum degree of control, resulting in the minimum emission rate, is a combination of dry low NO_X controls in the turbine and selective catalytic reduction (SCR) to achieve a short-term NO_X limit of 2.0 ppm.

The cost analysis presented in this response does not imply that a NO_X limit of 1.5 ppm is either technologically achievable or is “achieved in practice”, as that term is used in the context of a BACT determination. To the contrary, we provide the following reasons why a 1.5 ppm NO_X limit is inappropriate for CCGS:

- We can find no established BACT limits for NO_X less than 2.0 ppm (1-hour average) that have been “achieved in practice”, as that term is applied in the context of a BACT determination.
- It has not been established that 1.5 ppm can technology be achieved for the type of turbine proposed for CCGS, especially over the entire gas turbine operating range. Issues related to mixing of ammonia in the stack gas, and flow and concentration stratification across the exhaust path, become increasingly important at lower NO_X concentrations, especially while operating with an ammonia slip limit of 5 ppm.
- A limit of 1.5 ppm restricts the plant operating flexibility in response to grid demands for rapid load changes. Operating flexibility is increasingly critical for grid stability with the penetration of variable renewable power to the mix of power generation. While the GE turbine is capable of rapid load changes within emission compliance, the SCR ammonia injection control system may not be able to respond quickly enough to ensure

compliance with both a 1.5 ppm NO_X limit and a 5 ppm NH_3 limit during rapid load changes. CCGS has contractual obligations to achieve certain ramp rate capabilities while maintaining emissions compliance. Unlike other recently permitted facilities, CCGS intends to meet such obligations without the need to define hours having high ramp rates as "transient hours", which then typically qualify for longer averaging periods.

- SCR efficiency degradation over time further challenges our ability to achieve such a limit on a long-term basis.
- A 1.5 ppm limit is approaching the limit of continuous in-stack NO_X monitoring to determine compliance.
- A 1.5 ppm limit does not adequately accommodate "real-world" conditions within the heat recovery steam generator (HRSG). For instance, at operating temperature of approximately 750 deg F, there is a significant amount of thermal expansion that occurs within the HRSG where the SCR catalyst is located. Thermal cycling is expected to increase in the future as more and more renewable energy is added to the California grid. This thermal cycling tends to damage the seals that prevent gas turbine exhaust from bypassing the catalyst. These seals are typically inspected and repaired during annual plant outages. With a limit of 1.5 ppm, it is likely that more frequent outages will be required to inspect and repair these seals. If additional outages are required specifically to inspect and repair catalyst seals, the economic impact resulting from the downtime in terms of loss revenue from energy sales and capacity payments will be significant.
- The SCR will be provided as part of the HRSGs which, in turn, will be provided as part of GE's Engineered Equipment Package (EEP); a necessary requirement in order to obtain the Rapid Response design. GE's guarantee to CCGS is for a NOx limit of 2.0 ppm (see attached letter). GE will not guarantee a NO_X limit of 1.5 ppm. Without a GE guarantee, it will be extremely difficult, if not impossible, for CCGS to obtain financing for the construction of the Oakley Generation Station.

We note from the Russell City Statement of Basis (prepared by the BAAQMD) for establishing emission limits beyond the current achieved in practice BACT guideline:

> "The Air District disagrees with the comments that the mere issuance of a permit with a particular limit establishes that limit as BACT, without some further demonstration that the limit is achievable. A permitting agency may issue permits with very stringent limits with little or no technical justification at all if the applicant does not object to it. In such a situation, where there is no justification for the limit, nor any operating data to show that the limit can be complied with, the mere existence of the permit limit would not,

without more, establish that the limit is achievable as a technical matter." (Bay Area AQMD, Responses to Public Comments, Federal Prevention of Significant Deterioration Permit, Russell City Energy Center. February 2010. p. 68, fn 136)

Based on the assessment of data, and on the large number of permitting agencies that have required other similar facilities to limit NO_X emissions to 2.0 ppm averaged over 1 hour, the Air District concluded for Russell City that its NO_X limit of 2.0 ppm limit (1-hour average) should be required as BACT. Further, the District stated, "If this limit is being applied and demonstrably achieved at other facilities, that fact supports a presumption that it is an achievable limitation at this facility for purposes of BACT." Thus, the District concluded, the case of the Russell City Energy Center, that BACT for NO_X was a limit of 2.0 ppm, without any assessment of a possible 1.5 ppm NO_X limit. We are unaware of any new facts or changed circumstances that would lead to a different conclusion for CCGS.

Table 1 summarizes the cost effectiveness of SCR on the turbine/HRSG and follows the OAQPS Guidelines, which are also referenced in the table. For conservatism, it was assumed that the base case for the turbine/HRSG would be low NO_X design at 9 ppm. In reality, the BAAQMD would not allow the installation of a turbine with NO_X emissions in the 9 ppm range, so the base case analysis should be set to 2.0 ppm, which is the current established BACT for this category of source. However, to conservatively calculate the cost effectiveness, the NO_X emission decrease was based on 9 ppm, which when controlled downward to 1.5 ppm, the per turbine/HRSG emission would be 197.1 tons per year. Using the BAAQMD "BACT/TBACT Policy and Implementation Procedures", the NO_X cost effectiveness threshold is $17,500 per ton. Based on the results in Table 1, the cost effectiveness of removal from 9 ppm to 1.5 ppm NO_X is $18,600 per ton removed. The incremental cost from the established BACT base case of 2.0 ppm down to 1.5 ppm results in cost effectiveness of $177,000 per ton of removal, as summarized in Table 2 and is derived from the cost assumptions in Table 3. Based on both the base cost of NO_X control to 1.5 ppm and the incremental cost to 1.5 ppm, the use of SCR to control NO_X emissions to 1.5 ppm is considered uneconomical and is therefore, not considered BACT.

GE Energy

Peter J. Bukunt
Account Executive

6130 Stoneridge Mall Rd. Suite 300B
Pleasanton, CA 94588
USA

T 925-750-6110
F 925-730-6425
pete.bukunt@ge.com

October 11, 2010

Ms. Kathleen Truesdell
Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

RE: Oakley Generating Station – NOx Guarantees

Dear Ms. Truesdell

General Electric (GE Energy) is supplying the power island equipment for the Oakley Generating Station. Included within GE's scope of supply are the two (2) GE 7FA.05 gas turbines, two (2) HRSG's , two (2) SCR's, two (2) oxidation catalysts, one (1) GE D11 steam turbine, CEMS and plant distributed control system. Commercially, GE is providing the overall performance guarantees ("wrap") for the power island, which include, among other things, guarantees of output, heat rate, and emissions.

We have assisted Contra Costa Generating Station LLC (CCGS LLC) in their ongoing dialogue with the Bay Area Air Quality Management District with numerous analyses and the provision of an extensive amount of data. As the district finalizes its permit limit analysis for NOx, it should be cognizant of the fact that GE, having the overall performance wrap for the power island, sees no basis for and will not guarantee an hourly limit for NOx emissions below 2 ppm for any averaging period.

If you have any questions regarding this, feel free to contact me

Sincerely,

Pete Bukunt

Cc: J McLucas, Radback
C Matis, GE

Table 1

Radback Energy-OGS
SCR Catalyst Control System (per turbine)
Pollutant Controlled: NOx

CAPITAL COST SUMMARY

DIRECT CAPITAL COSTS		Explanation of Cost Estimates (2010 $)
1. Purchased Equipment:		**Base Cost - 9 ppm to 1.5 ppm**
A) Purchased Equipment Costs	$1,547,000	Avg Cost from Refs 1-4 and 6-11
B) Other Required Systems (ammonia system)	$980,000	see Cost Est tab
C) Instrumentation & Controls	$154,700	EPA OAQPS 10% of A
D) Freight	$126,350	EPA OAQPS 5% of A+B
E) Taxes	$221,240	8.25% Tax Rate (California avg)
Total Purchased Equip. Costs (TEC):	$3,029,290	
2. Installation Costs:		
A) Foundation & Supports	$302,900	EPA OAQPS 10% of TEC
B) Erection and Handling	$1,060,300	EPA OAQPS 35% of TEC
C) Electrical	$181,800	EPA OAQPS 6% of TEC
D) Piping	$242,300	EPA OAQPS 8% of TEC
E) Insulation	$60,600	EPA OAQPS 2% of TEC
F) Painting	$121,200	EPA OAQPS 4% of TEC
G) Site Preparation	$41,800	estimated by Project engineer
Total Installation Costs (TINC):	$2,010,900	
Total Direct Capital Costs (TDCC):	$5,040,190	Sum TEC,TINC
INDIRECT CAPITAL COSTS		
1. Engineering & Supervision	$454,400	EPA OAQPS 15% of TEC
2. Construction and Field Exp.	$302,900	EPA OAQPS 10% of TEC
3. Contractor Fees	$151,500	EPA OAQPS 5% of TEC
4. Start-up	$30,300	EPA OAQPS 1% of TEC
5. Performance Testing	$30,300	EPA OAQPS 1% of TEC
Total Indirect Capital Costs (TICC):	$969,400	
Total Direct & Indirect Capital Costs (TDICC):	$6,009,590	Sum TDCC,TICC
Contingency (@ 3%):	$180,300	3% TDICC (EPA OAQPS)
TOTAL CAPITAL COSTS (TCC):	$6,189,890	Sum TDICC,Contingency

ANNUAL OPERATING COST SUMMARY

DIRECT OPERATING COSTS		Explanation of Cost Estimates
1. Operating Labor	$56,963	1.5 hr/day, @108.50 hr, 350 days/yr
2. Supervisory Labor	$4,272	EPA OAQPS 15% Operating Labor
3. Maintenance Labor	$37,975	1 hr/day, @108.50 hr, 350 days/yr
4. Maintenance Materials	$37,975	100% of maintenance labor costs
4. Utility Expenses (electricity, plus fuel penalty cost)	$264,384	see Cost Est tab
5. Media replacement and disposal (catalyst, every 3 yrs)	$427,480	see Cost Est tab
6. Process chemicals costs (ammonia)	$103,672	see Cost Est tab
7. Annual Media Cost	$196,783	Item 5 divided by media life (yrs), x CRF (7%, 3 yrs, = 0.381)
8. Other Penalties (specify)	$2,155,660	Loss power sales $, added SCR maint., see Cost Est tab
Total Direct Operating Costs (TDOC):	$2,857,685	
INDIRECT OPERATING COSTS		
1. Overhead	$36,741	60% Total Labor, EPA OAQPS
Total Indirect Operating Costs (TIOC):	$36,741	
CAPITAL CHARGES & COSTS		
1. Property Tax	$91,600	EPA OAQPS 1.48% TCC
2. Insurance	$61,900	EPA OAQPS 1% TCC
3. General Administrative	$123,800	EPA OAQPS 2% TCC
4. Capital Recovery Cost	$498,900	7% per OMB, 30 yr plant life, CRF=.0806
Total Capital Charges Costs (TCCC):	$776,200	Sum 1,2,3,4
TOTAL ANNUALIZED OPERATING COSTS:	$3,670,626	Sum TDOC,TIOC,TCCC

COST EFFECTIVENESS EVALUATION

Uncontrolled Case Emissions		
Base Concentration-Uncontrolled	9	ppm with DLN Combustors
Annual Emission Rate	236.7	tpy (steady state emissions only)
Incremental Controlled Emissions Case		
NOx Concentration	1.5	ppm with SCR
Annual Emission Rate:	39.59	tpy
NOx Reduction from Uncontrolled Case:	197.1	tpy
Control Cost Effectiveness:	**$18,600**	per ton NOx

References:

1. OAQPS - OAQPS Cost Control Manual, 6th ED., January 2002, EPA
2. EPA1998 - Cost Effectiveness fo Oxidation Catalyst Control of HAP Emissions from Stationary Combustion Turbines, EPA, 1998.
3. NE estimated cost for additional catalyst to achieve 90% control of CO per EPA study.
4. EPA memo dated 12-30-99, ES Division, Docket A-95-51, and May 14, 1999 memo on Stationary CT control cost options.
5. Air Compliance Advisor, Version 7.5, 8-15-2003, EPA-OAQPS. (consulted ref only)
6. SATSOP CT Project, Phase II, SCA Amendment #4, Nov 2001.

References continued:

7. Tesla Power Project, FPL, AFC Section 5.2, October 2001.
8. West County Energy Center, FPL, August 2005.
9. JEA-Greenland Energy Center, B&V, Sept 2008.
10. Vineyard Energy Center, Calpine, Utah DEQ, November 2003.
11. Marsh Landing GS project data scaled to OGS site.
12. Optimization of Ammonia Source for SCR Applications, Paper #46 R.Salib, et.al., Washington Group Int'l., no date.

Ammonia system cost:

NH3:	29% aqueous	Unit Totals	Unit Cost, $	
tank cap (gals)	18,000	1	$0	Use JEA Greenland system cost for 7FA turbines, $980K/turbine
skids needed:	1 per turbine	2	$0	see Ref #9.
unloading system	1 per facility	1	$0	
Est Cost			$0	per turbine>>>> $0
tank fill capacity at 85%, gals:		15,300		Standard RMP admin capacity limit.
ammonia density, lbs/gal:		7.50		LaRoche Industries, Inc., Ammonia Technical Data Manual, 1997.

Labor costs: $/hr	$108.50	burdened labor costs (per PG&E)

Electricity Cost:

Req'd kw/hr	80	per turbine	Supplied by project team, ammonia forwarding, vaporization, etc.
cents/kw-hr	10.22		EIA-DOE Retail Electricity price listing, 9-15-10, Industrial sector, California.
Ops hrs/yr	8,463		Supplied by project team-AFC
Cost $/hr	$8.18		
Cost $/OP-Yr	$69,193		

Gas Cost:

Req'd 1000scf/hr	0	per turbine	Supplied by project team
$/1000scf	$4.35		EIA-DOE NG Price listing, 2009, as of 10-5-10, Electric Power Price, California.
Ops hrs/yr	8,463		Supplied by project team-AFC
Cost $/hr	$0		
Cost $/OP-yr	$0		

Fuel/Efficiency Penalties:

system backpressure, inH2O:	2.40	per turbine	GE heavy frame turbine estimate, Panda Gila River Project, PSD Appl., April 2000
fuel penalty per inH2O:	0.00105	0.0025	GRI General Fuel penalty value, EPA Memo 12-30-99,R. Sims-ESD, Docket A-95-51
max hourly fuel rate, 1000scf/hr:	2,104.0		Supplied by project team-AFC
Ops hrs/yr	8,463		Supplied by project team-AFC
$/1000scf	$4.35		EIA-DOE NG Price listing, 2009, as of 10-5-10, Electric Power Price, California.
fuel penalty/hr, 1000scf	5.3021		
fuel penalty/yr, 1000scf	44,872		
fuel penalty cost, $/hr	$23.06		
fuel penalty cost, $/yr	$195,191		

Annual Ammonia supply costs:		per turbine	
ammonia injection rate, lbs/hr:	70.00		Supplied by project team-AFC
ammonia injection Ops, hrs/yr	8,463		Supplied by project team-AFC
total ammonia used, lbs/yr	592,410		
total ammonia used, gals/yr	78,988		
total ammonia used, tons/yr	296.21		
ammonia cost, $/ton	$350		Materials + freight, ICIS.com, August 2010, and USDA-ERS, Bulletin WRS-0702, 8/07.
annual ammonia cost, $	$103,672		
annual tank turnovers at 85% cap:	5.16		

Lost Power Sales Revenue

avg baseload day power sales, $	$410,300	plant wide	Supplied by project engineering team (624 MW nominal)
# days/yr downtime due to system	5 days x 2 events		Market Rate of $20/kw
inspection and maintenance issues	10		Supplied by project engineering team
total lost power sales revenue, $/yr	$4,103,000	plantwide	
	2,051,500		
SCR catalyst replacement cost		per turbine	
replacement cost, $	$427,480		Supplied by project engineering team

Annual SCR Maintenance/Inspections

# of laborers	12
# hrs/day per laborer	8
# days per laborer	10
annual cost, $	$104,160

Cost Multiplier Values Per OAQPS*

Cost Parameter	OAQPS Value Range, %	Value Used in Analysis,%	Comment
Instrumentation/Controls	10%	10%	
Freight	5%	5%	
Taxes	3%	8.25%	local area tax rate
Foundations/Supports	4-12%	10%	
Erection/Handling	14-50%	35%	per project developer
Electrical	1-8%	6%	per project developer
Piping	1-30%	8%	per project developer
Insulation	1-7%	2%	per project developer
Painting	1-4%	4%	per project developer
Site Preparation	as Req'd	1.5%	1.5% of TEC
Engineering/Supervision	10-20%	15%	per project developer
Construction	5-20%	10%	per project developer
Contractor Fees	0-10%	5%	per project developer
Startup Costs	1-2%	1%	per project developer
Performance Testing	1%	1%	
Contingency	3%	3%	
Supervisory Labor	15%	15%	15% of OP labor
Maintenance Materials	100%	100%	100% of maintenance labor costs
Overhead	60%	60%	BAAQMD value is 80%
Administrative Charges	2%	2%	
Property Taxes	1%	1.48%	per project developer
Insurance	1%	1%	
Capital Recovery Factor	calculated	calculated	OMB interest rate 7%

* OAQPS - OAQPS Cost Control Manual, 6th ED., January 2002, EPA.

Table 2

Radback Energy-OGS

SCR Catalyst Control System (per turbine)

Pollutant Controlled: NOx

CAPITAL COST SUMMARY

DIRECT CAPITAL COSTS		Explanation of Cost Estimates (2010 $)
1. Purchased Equipment:		**Base Cost - 9 ppm to 2 ppm**
A) Purchased Equipment Costs	$1,400,000	Avg Cost from Refs 1-4 and 6-11
B) Other Required Systems (ammonia system)	$980,000	see Cost Est tab
C) Instrumentation & Controls	$140,000	EPA OAQPS 10% of A
D) Freight	$119,000	EPA OAQPS 5% of A and B
E) Taxes	$207,900	8.25% Tax Rate (California avg)
Total Purchased Equip. Costs (TEC):	$2,846,900	
2. Installation Costs:		
A) Foundation & Supports	$284,700	EPA OAQPS 10% of TEC
B) Erection and Handling	$996,400	EPA OAQPS 35% of TEC
C) Electrical	$170,800	EPA OAQPS 6% of TEC
D) Piping	$227,800	EPA OAQPS 8% of TEC
E) Insulation	$56,900	EPA OAQPS 2% of TEC
F) Painting	$113,900	EPA OAQPS 4% of TEC
G) Site Preparation	$41,800	1.5% of TEC
Total Installation Costs (TINC):	$1,892,300	
Total Direct Capital Costs (TDCC):	$4,739,200	Sum TEC,TINC
INDIRECT CAPITAL COSTS		
1. Engineering & Supervision	$427,000	EPA OAQPS 15% of TEC
2. Construction and Field Exp.	$284,700	EPA OAQPS 10% of TEC
3. Contractor Fees	$142,300	EPA OAQPS 5% of TEC
4. Start-up	$28,500	EPA OAQPS 1% of TEC
5. Performance Testing	$28,500	EPA OAQPS 1% of TEC
Total Indirect Capital Costs (TICC):	$911,000	
Total Direct & Indirect Capital Costs (TDICC):	$5,650,200	Sum TDCC,TICC
Contingency (@ 3%):	$169,500	3% TDICC (EPA OAQPS)
TOTAL CAPITAL COSTS (TCC):	$5,819,700	Sum TDICC,Contingency

ANNUAL OPERATING COST SUMMARY

DIRECT OPERATING COSTS		Explanation of Cost Estimates
1. Operating Labor	$56,963	1.5 hr/day, @108.50 hr, 350 days/yr
2. Supervisory Labor	$4,272	EPA OAQPS 15% Operating Labor
3. Maintenance Labor	$37,975	1 hr/day, @108.50 hr, 350 days/yr
4. Maintenance Materials	$37,975	100% of maintenance labor costs
4. Utility Expenses (electricity, plus fuel penalty cost)	$227,528	see Cost Est tab
5. Media replacement and disposal (catalyst, every 3 yrs)	$362,780	see Cost Est tab
6. Process chemicals costs (ammonia)	$99,229	see Cost Est tab
7. Annual Media Cost	$167,000	Item 5 divided by media life (yrs), x CRF (7%, 3 yrs, = 0.381)
8. Other Penalties (specify)	$0	Loss power sales $, added SCR maint., see Cost Est tab
Total Direct Operating Costs (TDOC):	$630,942	
INDIRECT OPERATING COSTS		
1. Overhead	$36,741	60% Total Labor, EPA OAQPS
Total Indirect Operating Costs (TIOC):	$36,741	
CAPITAL CHARGES & COSTS		
1. Property Tax	$86,100	EPA OAQPS 1.48% TCC
2. Insurance	$58,200	EPA OAQPS 1% TCC
3. General Administrative	$116,400	EPA OAQPS 2% TCC
4. Capital Recovery Cost	$469,100	7% per OMB, 30 yr plant life, CRF=.0806
Total Capital Charges Costs (TCCC):	$729,800	Sum 1,2,3,4
TOTAL ANNUALIZED OPERATING COSTS:	$1,397,483	Sum TDOC,TIOC,TCCC

COST EFFECTIVENESS EVALUATION

Uncontrolled Case Emissions		
Base Concentration-Uncontrolled	9	ppm with DLN Combustors
Annual Emission Rate	236.7	tpy (steady state emissions only)
Incremental Controlled Emissions Case		
NOx Concentration	2.0	ppm with SCR
Annual Emission Rate:	52.60	tpy
NOx Reduction from Uncontrolled Case:	184.1	tpy
Control Cost Effectiveness:	**$7,600**	per ton NOx

References:

1. OAQPS - OAQPS Cost Control Manual, 6th ED., January 2002, EPA
2. EPA1998 - Cost Effectiveness fo Oxidation Catalyst Control of HAP Emissions from Stationary Combustion Turbines, EPA, 1998.
3. NE estimated cost for additional catalyst to achieve 90% control of CO per EPA study.
4. EPA memo dated 12-30-99, ES Division, Docket A-95-51, and May 14, 1999 memo on Stationary CT control cost options.
5. Air Compliance Advisor, Version 7.5, 8-15-2003, EPA-OAQPS. (consulted ref only)
6. SATSOP CT Project, Phase II, SCA Amendment #4, Nov 2001.

References continued:

7. Tesla Power Project, FPL, AFC Section 5.2, October 2001.
8. West County Energy Center, FPL, August 2005.
9. JEA-Greenland Energy Center, B&V, Sept 2008.
10. Vineyard Energy Center, Calpine, Utah DEQ, November 2003.
11. Marsh Landing GS project data scaled to OGS site.
12. Optimization of Ammonia Source for SCR Applications, Paper #46, R.Salib, et.al., Washington Group Int'l., no date.

Ammonia system cost:

NH3:	29% aqueous	Unit Totals	Unit Cost, $	
tank cap (gals)	18,000	1	$0	Use JEA Greenland system cost for 7FA turbines, $980K/turbine
skids needed:	1 per turbine	2	$0	see Ref #9.
unloading system	1 per facility	1	$0	
Est Cost			$0	per turbine>>>> $0
tank fill capacity at 85%, gals:		15,300		Standard RMP admin capacity limit.
ammonia density, lbs/gal:		7.50		LaRoche Industries, Inc., Ammonia Technical Data Manual, 1997.

Labor costs: $/hr $108.50 burdened labor costs (per PG&E)

Electricity Cost:

Req'd kw/hr	75		per turbine	Supplied by project team, ammonia forwarding, vaporization, etc.
cents/kw-hr	10.22			EIA-DOE Retail Electricity price listing, 9-15-10, Industrial sector, California.
Ops hrs/yr	8,463			Supplied by project team-AFC
Cost $/hr	$7.67			
Cost $/OP-Yr	$64,869			

Gas Cost:

Req'd 1000scf/hr	0		per turbine	Supplied by project team
$/1000scf	$4.35			EIA-DOE NG Price listing, 2009, as of 10-5-10, Electric Power Price, California.
Ops hrs/yr	8,463			Supplied by project team-AFC
Cost $/hr	$0			
Cost $/OP-yr	$0			

Fuel/Efficiency Penalties:

system backpressure, inH2O:	2.00	per turbine	GE heavy frame turbine estimate, Panda Gila River Project, PSD Appl., April 2000
fuel penalty per inH2O:	0.00105	0.0021	GRI General Fuel penalty value, EPA Memo 12-30-99,R. Sims-ESD, Docket A-95-51
max hourly fuel rate, 1000scf/hr:	2,104.0		Supplied by project team-AFC
Ops hrs/yr	8,463		Supplied by project team-AFC
$/1000scf	$4.35		EIA-DOE NG Price listing, 2009, as of 10-5-10, Electric Power Price, California.
fuel penalty/hr, 1000scf	4.4184		
fuel penalty/yr, 1000scf	37,393		
fuel penalty cost, $/hr	$19.22		
fuel penalty cost, $/yr	$162,659		

Annual Ammonia supply costs:		per turbine	
ammonia injection rate, lbs/hr:	67.00		Supplied by project team-AFC
ammonia injection Ops, hrs/yr	8,463		Supplied by project team-AFC
total ammonia used, lbs/yr	567,021		
total ammonia used, gals/yr	75,603		
total ammonia used, tons/yr	283.51		
ammonia cost, $/ton	$350		Materials + freight, ICIS.com, August 2010, and USDA-ERS, Bulletin WRS-0702, 8/07.
annual ammonia cost, $	$99,229		
annual tank turnovers at 85% cap:	4.94		

Lost Power Sales Revenue

avg baseload day power sales, $	$0	per turbine	Supplied by project engineering team
# days/yr downtime due to system inspection and maintenance issues	5		Supplied by project engineering team
total lost power sales revenue, $/yr	$0		

SCR catalyst replacement cost		per turbine	
replacement cost, $	$362,780		Supplied by project engineering team

Annual SCR Maintenance/Inspections

# of laborers	0
# hrs/day per laborer	0
# days per laborer	0
annual cost, $	$0

Cost Multiplier Values Per OAQPS*

Cost Parameter	OAQPS Value Range, %	Value Used in Analysis,%	Comment
Instrumentation/Controls	10%	10%	
Freight	5%	5%	
Taxes	3%	8.25%	local area tax rate
Foundations/Supports	4-12%	10%	
Erection/Handling	14-50%	35%	per project developer
Electrical	1-8%	6%	per project developer
Piping	1-30%	8%	per project developer
Insulation	1-7%	2%	per project developer
Painting	1-4%	4%	per project developer
Site Preparation	as Req'd	1.5%	1.5% of TEC
Engineering/Supervision	10-20%	15%	per project developer
Construction	5-20%	10%	per project developer
Contractor Fees	0-10%	5%	per project developer
Startup Costs	1-2%	1%	per project developer
Performance Testing	1%	1%	
Contingency	3%	3%	
Supervisory Labor	15%	15%	15% of OP labor
Maintenance Materials	100%	100%	100% of maintenance labor costs
Overhead	60%	60%	BAAQMD value is 80%
Administrative Charges	2%	2%	
Property Taxes	1%	1.48%	per project developer
Insurance	1%	1%	
Capital Recovery Factor	calculated	calculated	OMB interest rate 7%

* OAQPS - OAQPS Cost Control Manual, 6th ED., January 2002, EPA.

Table 3

Radback Energy-OGS

SCR Catalyst Control System (per turbine)

Pollutant Controlled: NOx

	CAPITAL COST SUMMARY	
DIRECT CAPITAL COSTS		Explanation of Cost Estimates (2010 $)
1. Purchased Equipment:		**INCREMENTAL Cost - 2 ppm to 1.5 ppm**
A) Purchased Equipment Costs	$147,000	**Cost differential from 9-2 versus 9-1.5 ppm**
B) Other Required Systems (ammonia system)	$0	
C) Instrumentation & Controls	$14,700	
D) Freight	$7,350	
E) Taxes	$13,947	
Total Purchased Equip. Costs (TEC):	$182,997	
2. Installation Costs:		
A) Foundation & Supports	$14,600	
B) Erection and Handling	$64,000	
C) Electrical	$11,000	
D) Piping	$14,600	
E) Insulation	$3,600	
F) Painting	$7,400	
G) Site Preparation	$0	
Total Installation Costs (TINC):	$115,200	
Total Direct Capital Costs (TDCC):	$298,197	Sum TEC,TINC
INDIRECT CAPITAL COSTS		
1. Engineering & Supervision	$27,400	
2. Construction and Field Exp.	$18,300	
3. Contractor Fees	$9,100	
4. Start-up	$1,900	
5. Performance Testing	$1,900	
Total Indirect Capital Costs (TICC):	$58,600	
Total Direct & Indirect Capital Costs (TDICC):	$356,797	Sum TDCC,TICC
Contingency (@ 3%):	$10,700	
TOTAL CAPITAL COSTS (TCC):	$367,497	Sum TDICC,Contingency
	ANNUAL OPERATING COST SUMMARY	
DIRECT OPERATING COSTS		Explanation of Cost Estimates
1. Operating Labor	$0	**INCREMENTAL Cost - 2 ppm to 1.5 ppm**
2. Supervisory Labor	$0	**Cost differential from 9-2 versus 9-1.5 ppm**
3. Maintenance Labor	$0	
4. Maintenance Materials	$0	
4. Utility Expenses (gas and electricity, plus fuel penalty cost)	$36,856	
5. Media replacement and disposal (catalyst, every 3 yrs)	$64,700	
6. Process chemicals costs (ammonia)	$4,443	
7. Annual Media Cost	$59,286	
8. Other Penalties (specify)	$2,155,660	
Total Direct Operating Costs (TDOC):	$2,256,245	
INDIRECT OPERATING COSTS		
1. Overhead	$0	
Total Indirect Operating Costs (TIOC):	$0	
CAPITAL CHARGES & COSTS		
1. Property Tax	$5,400	
2. Insurance	$3,700	
3. General Administrative	$7,300	
4. Capital Recovery Cost	$29,700	
Total Capital Charges Costs (TCCC):	$46,100	Sum 1,2,3,4
TOTAL ANNUALIZED OPERATING COSTS:	$2,302,345	Sum TDOC,TIOC,TCCC
	COST EFFECTIVENESS EVALUATION	
Controlled Case Emissions		
Base Concentration-Controlled	2	ppm with DLN Combustors and SCR
Annual Emission Rate	52.6	tpy (steady state emissions only)
Incremental Controlled Emissions Case		
NOx Concentration	1.5	ppm with added SCR
Annual Emission Rate:	39.59	tpy
NOx Reduction from Controlled Case:	13.0	tpy
Control Cost Effectiveness:	**$177,000**	per ton NOx

References:

1. OAQPS - OAQPS Cost Control Manual, 6th ED., January 2002, EPA
2. EPA1998 - Cost Effectiveness fo Oxidation Catalyst Control of HAP Emissions from Stationary Combustion Turbines, EPA, 1998.
3. NE estimated cost for additional catalyst to achieve 90% control of CO per EPA study.
4. EPA memo dated 12-30-99, ES Division, Docket A-95-51, and May 14, 1999 memo on Stationary CT control cost options.
5. Air Compliance Advisor, Version 7.5, 8-15-2003, EPA-OAQPS. (consulted ref only)
6. SATSOP CT Project, Phase II, SCA Amendment #4, Nov 2001.

References continued:

7. Tesla Power Project, FPL, AFC Section 5.2, October 2001.
8. West County Energy Center, FPL, August 2005.
9. JEA-Greenland Energy Center, B&V, Sept 2008.
10. Vineyard Energy Center, Calpine, Utah DEQ, November 2003.
11. Marsh Landing GS project data scaled to OGS site.
12. Optimization of Ammonia Source for SCR Applications, Paper #46, R.Salib, et.al., Washington Group Int'l., no date.