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May 20, 2010

Ms. Felicia Miller
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Subject: Oakley Generating Station Project (09-AFC-4)
Contra Costa Generating Station LLC's Responses to BAAQMD Questions
Received on April 15, 2010

Dear Ms. Miller:

Attached are three (3) hard copies of the Contra Costa Generating Station LLC's response to questions from the Bay Area Air Quality Management District (BAAQMD) received on April 15, 2010.

If you have any questions, please contact me at (916) 286-0278.

Sincerely,
CH2M HILL

Douglas M. Davy, Ph.D.
AFC Project Manager

Attachment
cc: POS List
Project File

CCGS LLC Responses to BAAQMD Questions Received on 4/15/2010

1. Project:

    a. Please provide ton/year pollutant limits to the thousandth place.

    Response:
    NO_X – 98.768 tons
    CO – 98.816 tons
    POC – 29.487 tons
    PM10 – 76.337 tons
    SO_2 – 12.553 tons

    b. Please explain why the commissioning period is longer than conventional combined cycle plants. What testing scenarios are required because of the Rapid Response capability (HRSG operation on steam bypass)?

    Response: The commissioning period proposed for the Oakley Generating Station (OGS) should be similar to other combined cycle projects of similar configuration (i.e. 2x1 configuration with General Electric (GE) 7FA combustion turbines and an air-cooled condenser). The Rapid Response aspect of the plant design and the newness of the 7FA.05 should not add to the commissioning time as compared to other combined cycle projects. That said, it should be noted that the OGS is somewhat unique in that ownership of the OGS will be transferred to Pacific Gas and Electric Company (PG&E) at commercial operation. Prior to the transfer of ownership, there are numerous tests that need to be conducted and performance features that need to be demonstrated to PG&E. Because of this, CCGS LLC (CCGS) has attempted to conservatively estimate the duration of the commissioning period for the OGS to allow sufficient time to thoroughly commission the project. Where other projects may have the luxury of fine tuning control systems and startup/shutdown sequences during the first year of operation, CCGS must complete these same tasks prior to the transfer of ownership.

    c. What is the appropriate limitation on commissioning hours with no/partial control for each turbine based on manufacturer's estimates? If a total facility-wide commissioning hours limit of 831 hours is more appropriate, please explain why.

    Response: CCGS would prefer that the a total facility-wide limit of 831 hours be used. The net result is the same whether limits are provided individually to each gas turbine or combined for a facility-wide limit. The facility-wide limit will provide CCGS greater flexibility. For instance, if commissioning the first unit actually requires more hours than projected, unused hours from the second unit could be applied to the first unit.

d. Please explain Rapid Response in more detail.

Response: Rapid Response is GE's term for their combined-cycle design wherein, during a startup, the combustion turbine(s) are allowed to load at a simple-cycle rate. With a conventional combined cycle design, the loading of the combustion turbine(s) is restricted during startups for two reasons; 1) to allow the heat recovery steam generator (HRSG) to heat up slowly, thus minimizing thermal stresses, and 2) to allow the temperature of the steam entering the steam turbine to match the steam turbine metal temperature which also minimizes thermal stresses and is a key to maintaining the necessary clearances between the rotating and stationary components of the steam turbine. With the Rapid Response design, GE will not only be providing the combustion turbine(s) and steam turbine, but also the HRSG. The HRSG will be specially designed to heat up rapidly without generating excessive stresses. Other key components of the Rapid Response design are the steam bypass and attemperation systems. These systems allow steam generated by the HRSGs to bypass the steam turbine during startups and go directly to the air-cooled condenser. As the proper steam conditions are achieved, a portion of the steam will be sent to the steam turbine. The steam turbine load will ramp up slowly until the point is reached where steam is no longer bypassing the steam turbine. The steam bypass system includes the following bypass valves for each HRSG:

- High pressure (HP) steam to cold reheat steam
- HP steam to the air-cooled condenser
- Hot reheat steam to the air-cooled condenser
- Low pressure (LP) steam to the air-cooled condenser

In addition to the attemperators normally included upstream of the final HP superheater and final reheater sections of the HRSG, the design will include terminal attemperators in the HP and hot reheat steam lines leaving each HRSG.

2. Turbines:

a. PM BACT. Please explain why 7.5 lb/hr total PM is not achievable for these turbines. Please include supporting data from combined-cycle F Class turbines.

Response: An emissions rate of 7.5 lb/hr of total PM will likely be achievable the majority of the time, but not with the certainty that CCGS or GE would like to see. The proposed PM level of 9.0 lb/hr is based on the guarantee provided by the combustion turbine manufacturer, GE. A letter from GE explaining the basis of the 9.0 lb/hr value will be submitted to the District confidentially.

b. CO/POC BACT. Please provide a cost-effectiveness and feasibility analysis for an oxidation catalyst capable of consistently maintaining emissions below 2.0 ppm CO (and 1.0 ppm POC). What is the lowest emission limits for CO and POC the vendor will guarantee? Recent BAAQMD evaluations of proposed power plants have evaluated the cost of oxidation catalysts capable of achieving 1.5 ppm CO for combined cycle plant (Russell City Energy Center) and 0.9 ppm CO for simple cycle plant (Marsh Landing Generating Station); neither was determined to be cost-effective.

Response: The cost and feasibility was assessed to reduce the CO emission limit from 2.0 ppm down to 1.0 ppm with the POC emission limit reduced from 1.0 ppm down to 0.8 ppm. The oxidation catalysts 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 CO limit of 2.0 ppm and a POC limit of 1.0 ppm.

The capital cost associated with the installation of additional catalyst includes the catalyst, catalyst housing, HRSG modifications, and balance of plant equipment. Capital costs are based on vendor supplied data as well as scaled estimates from previous budgetary quotations from equipment manufacturers and other engineering estimates. As shown in Table 1, the per combustion turbine total installed capital cost for the oxidation catalyst system is $550,566.

The annual operating costs associated with the use of a CO catalyst to go from 2.0 ppm down to 1.0 ppm would increase. The annual operating costs include catalyst replacement, energy impacts due to increased fuel usage, operating personnel, and maintenance. Throughout the life of the facility, the catalyst will require periodic replacement. Catalyst manufacturers typically guarantee a three-year catalyst life. As stated above, both add-on control systems increase the fuel usage of the facility for same net electrical output. This is a result of the increased combustion turbine backpressure resulting from the additional catalyst depth. Maintenance consists of the routine catalyst replacement costs. Labor for the operation and maintenance of the combustion control system is considered a part of the facilities normal operating expenses. The labor costs for the oxidation catalyst system include general maintenance of the system. The estimated additional annual operating cost associated with the oxidation catalyst at 1.0 ppm CO and 0.8 ppm POC is $150,352. Table 1 summarizes the cost effectiveness analysis.

The CO emission reduction from 2.0 ppm (with add-on controls) down to 1.0 ppm (or a 9.7 ton per year reduction) would yield an incremental control cost effectiveness of $15,500 per ton. At this cost, the proposed CO limit of 1.0 ppm would not be considered economical.

The POC emission reduction from 1.0 ppm (with add-on controls) down to 0.8 ppm (or a 2.2 ton per year reduction) would yield an incremental control cost effectiveness of $68,342 per ton. At this cost, the proposed POC limit of 0.8 ppm would not be considered economical.

The use of good combustion control technology and a catalyst to limit CO emissions to 2.0 ppmvd and POC at 1.0 ppmvd (@15% O_2) is proposed as BACT for the OGS based on the following rational:

- With an incremental cost of $15,500/ton for CO and $68,342/ton for POC, the application of additional oxidation catalyst down to 1.0 ppm CO and 0.8 ppm POC is not considered BACT.

- Installation of a larger oxidation catalyst system will have negative energy and environmental impacts. This increased control increases the backpressure on the combustion turbine, resulting in decreased efficiency and increased fuel consumption. The increased fuel consumption and decreased efficiency is an energy impact that also results in increases in other pollutant emissions per unit of energy.

- The use of a CO catalyst at 2.0 ppm with POC control at 1.0 ppm has previously been recognized as BACT for CO and POC control by regulatory agencies.

Therefore, the use of an oxidation catalyst to meet CO BACT requirements of 2.0 ppm (1-hour average during the unit steady operation) and POC BACT at 1.0 ppm is at least equal to or more stringent than other BACT determinations for similar power plants.

c. Startup/Shutdown Table 5.1-6. Should emissions limits for PM and SOx be the maximum event time multiplied by the max hourly rate? (example: Cold start: 90 min x 6.0 lb SO2/hr = 9.0 lb/cold start)

Response: The PM10 and SO_X values listed in Table 5.1-6 are the expected event times multiplied by the maximum hourly rates. For SO_X, the maximum hourly rate assumes the maximum sulfur concentration of 1 grain/100 scf. CCGS agrees that if startup/shutdown emissions limits are used for these two pollutants, such limits would more appropriately be based on the maximum event time multiplied by the maximum hourly rate, in which case the correct values would be:

- PM10 – Hot/warm start – 4.5 lbs
- PM10 – Cold start – 13.5 lbs
- PM10 – Shutdown – 9.0 lbs
- SO_X – Hot/warm start – 3.0 lbs
- SO_X – Cold start – 9.0 lbs
- SO_X – Shutdown – 6.0 lbs

Since these values are consistent with the worst-case values used for 24-hour PM10 modeling and 1-hr, 3-hr, and 24-hr SO_X modeling, no additional modeling is required to support these limits.

d. Please explain why the facility needs 60 minutes for shutdown. What steps are taking place? Are there special requirements for Rapid Response?

Response: Similar to the startups, the maximum duration indicated is approximately twice that of the expected duration provided by GE (i.e. 2 x 30 minutes = 60 minutes). There are no special requirements during shutdown for Rapid Response. During a conventional shutdown cycle, the combustion turbine load is ramped down to approximately 25% load and then held for approximately 5 minutes while the steam turbine coverts the thermal energy stored in the HRSG/steam cycle to electrical output. Once the steam turbine circuit breaker opens, the combustions turbine load is ramped down to 0% load and then the combustion turbine circuit breaker is opened and the flow of fuel is stopped. In addition to Rapid Response, the OGS design will include a feature GE calls Purge Credit. Without Purge Credit, it is necessary to purge the combustion turbine and HRSG with air at the beginning of the startup sequence, prior to admitting fuel to the combustors. This purge air is provided by the combustion turbine compressor. With Purge Credit, the purge cycle is moved to the end of the shutdown sequence and the combustion turbine fuel train is provided with a triple block and bleed system with a nitrogen plug to assure that no fuel enters the combustion turbine/HRSG while the unit is offline. At least one HRSG manufacturer has expressed concern regarding the admittance of “cool” purge air to the “hot” HRSG immediately following a conventional shutdown. The suggested remedy is to hold the combustion turbine at a low load for approximately 10 minutes during the shutdown cycle, thus allowing the HRSG to cool down more slowly. GE’s proposed shutdown time includes this additional cool-down period.

3. Boiler:

a. CO/POC BACT. Please provide a cost-effectiveness and feasibility analysis for an oxidation catalyst capable of consistently maintaining emissions below 10.0 ppm CO (and 5.0 ppm POC). What is the lowest emission limit for CO and POC the vendor will guarantee?

Response: The BACT/LAER Clearinghouse was reviewed for recent determinations for CO and POCs. Based on the summary in Table 2, BACT for CO for these types of boilers range from a high value of 400 ppm to a low value of 10 ppm. POC BACT ranges from the use of good combustion practices to 3 ppm. The OGS auxiliary boiler CO emission rate is already proposed at 10 ppm with POC at 5 ppm. For purposes of evaluating the cost differential for lower CO and POC values, CCGS has assumed that the boiler would have to be equipped with a CO oxidation catalyst, and the catalyst would achieve CO levels of 7 ppm on an annual average basis. CCGS is not making any claims or guarantees (stated or implied) that such a system will actually achieve the estimated CO and POC values, but that the assumed values were used only for purposes of evaluating control cost effectiveness.

CO oxidation catalysts, on average, cost approximately 50% of an SCR catalyst system for the combustion unit under evaluation *(Ref: Industrial Boilers and Heat Recovery Steam Generators: Design, Applications.., Chapter 4-Emissions Controls, V. Ganapathy, 2003)*, which would result in a CO catalyst capital cost for the proposed auxiliary boiler of approximately $115,000. Annual operations costs for the CO catalyst on the auxiliary boiler can range from 40-50% of the capital costs. The cost effectiveness analysis, presented in Table 3 assumed a worst-case annual hours of operation of 4,324 hours per year, which would result in the greatest emission reduction.

The CO emission reduction from 10 ppm (without add-on controls) down to 7 ppm (or a 0.24 ton per year reduction) would yield a control cost effectiveness of $290,318 per ton. At this cost, the proposed CO limit of 7 ppm would not be considered economical.

The POC emission reduction from 5 ppm (without add-on controls) down to 3 ppm (or a 0.1 ton per year reduction) would yield an incremental control cost effectiveness of $754,196 per ton. At this cost, the proposed POC limit of 3 ppm would not be considered economical.

Thus, the use of low emission CO burners along with good combustion control technology to limit CO emissions to 10 ppmvd and POC at 5 ppmvd (@ 3% O_2) is proposed as BACT for the OGS based high cost of adding additional controls. The use of good combustion practices, exclusive use of natural gas along with low emission CO burners have been recognized as BACT for CO and POC control by regulatory agencies.

4. Fire Pump Diesel Engine:

   a. Why are hourly emissions capped at 56 min?

      Response: NFPA requires weekly testing for a minimum of 30 minutes. CCGS wanted to provide some conservatism in the number of minutes allowed for each test so that there would not be a violation in the event the operator did not stop the test at exactly 30 minutes. In order to stay below 50 hours per year, and allowing for a total of 53 tests in a year, CCGS back-calculated 56 minutes as the average length of each test. A condition limiting the total testing hours to 49 or 50 hours per year and the length of each test to no more than 56 minutes would be acceptable.

   b. From the annual fuel usage in table 5.1-2, 991.1 gal/year divided by 20 gal/hr = 49.555 hours/year. Is the facility requesting 50 hours per year for non-emergency operation or 49 hours?

Response: CCGS assumed that operation needed to be less than 50 hours per year, so a limit of 49 hours for non-emergency operation would be acceptable.

5. Evaporative Fluid Cooler:

   a. What chemicals are added to the water onsite?

      Response: The chemicals that may be added to the circulating water within the evaporative fluid cooler are listed in Table 5.1.1 of the Application for Certification. They are:

      - Bromine-containing solution (e.g., NALCO STABREX® ST20)
      - Sodium dichloroisocyanurate/ Sodium bromide (e.g., NALCO
      - Sulfuric acid (93%)
      - Proprietary non-oxidizing biocide (e.g., NALCO 7330)
      - Proprietary corrosion/scale inhibitor (e.g., NALCO 3D TRASAR® 247/294)
      - Proprietary corrosion inhibitor (e.g., NALCO 73801WR)
      - Diagnostic tracer chemical (e.g., NALCO 3D TRASAR 3DTBR06)

   b. Are there any emissions from these chemicals? If so, please provide emissions calculations.

      Response: CCGS does not believe that there will be emissions from any of the above chemicals. CCGS reviewed the MSDS sheets for these chemicals and found none to have a VOC content of greater than 1 percent in the delivered form. The NALCO 7330 product was the only chemical indicated to have a VOC concentration greater than zero (0.8%).

6. Oil-water Separator:

   a. What exemption does this equipment fall under?
      Emissions will be included in facility total for permitted and exempt equipment. Emissions will not be subject to offset requirements unless the equipment requires a permit.

      Response: The oil water separator rule exemption fall under the BAAQMD Primary Exemption in Rule 2-1-103.1 and Secondary Exemption in Rule 8-8-113. The exemption is based on the following emission calculations:

      Oil Water Separator VOC Emissions Estimate
      Usage Units: 1000 gallons
      VOC Emissions Factor: 0.2 lbs VOC/usage unit or 0.2 lbs VOC/1000 gallons*
      Maximum operating rate: 0.12 usage units/hr = 120 gals/hr
      (0.2 lbs/1000 gallons) x (120 gallons/hr) = 0.024 lbs/hr
      @ 24 hrs/day = 0.58 lbs/day
      @365 days/yr = 0.11 tpy
      *AP-42, Section 5.1, Table 5.1-2, 1/95

TABLE 1
Radback Energy-OGS
Oakley, CA.
CO Catalyst Control Costs
CAPITAL COST SUMMARY

DIRECT CAPITAL COSTS (2010 $)		Explanation of Cost Estimates
		per Unit basis
1. Purchased Equipment:		Base Cost
A) Equipment Cost, EC	$200,000	Additional Catalyst Cost to Control CO from 2 to 1 ppm
B) Auxiliary Equipment, AE	$90,000	Specify if applicable
B) Instrumentation & Controls	$29,000	10% of EC+AE
C) Freight	$14,500	5% of EC+AE
D) Taxes	$23,200	8.00% of EC+AE (California avg sales tax value)
Total Purchased Equip. Costs (TEC):	$356,700	Sum 1A thru 1E
2. Installation Costs:		
A) Foundation & Supports	$0	12% of TEC
B) Erection and Handling	$53,505	15% of TEC
C) Electrical	$0	1% of TEC
D) Piping	$0	2% of TEC
E) Insulation	$0	1% of TEC
F) Painting	$0	1% of TEC
G) Site Preparation	$0	5% of TEC
Total Installation Costs (TIC):	$53,505	Sum 2A thru 2G
Total Direct Capital Costs (TDCC):	$410,205	TEC + TIC
INDIRECT CAPITAL COSTS		
1. Engineering & Supervision	$35,670	10% of TEC
2. Construction and Field Exp.	$35,670	10% of TEC
3. Contractor Fees	$35,670	10% of TEC
4. Start-up	$3,567	1 % of TEC
5. Performance Testing	$3,567	1% of TEC
Total Indirect Capital Costs (TICC):	$114,144	Sum 1 thru 5
Total Direct & Indirect Capital Costs (TDICC):	$524,349	TDCC + TICC
Contingency Costs = 5%	$26,217	5% TDICC
TOTAL CAPITAL COSTS (TCC):	$550,566	TDICC + Contingency

TABLE 1
Radback Energy-OGS
Oakley, CA.
CO Catalyst Control Costs
ANNUAL OPERATING COST SUMMARY

DIRECT OPERATING COSTS (2010 $)		Explanation of Cost Estimates
		per Unit basis
1. Operating Labor	$0	2 hrs/day, $42/hr, 365 days/yr
2. Supervisory Labor	$0	15% of Operating Labor
3. Maintenance Labor	$7,665	0.5 hr/day, $42/hr, 365 days/yr
4. Maintenance Materials	$7,665	100% of Maintenance Labor
5. Electricity Expense	$0	not applicable
6. Catalyst Cost (replace/disposal)	$0	15 year lifespan and replacement
7. Ammonia Costs	$0	not applicable
8. Fuel Penalty (@ $0.005/scf)	$64,000	0.15% per inch backpressure, assumed 1.5" bp
9. Annualized Catalyst Cost	$0	CRF, 7%, 15 yrs, = 0.1098
Total Direct Operating Costs (TDOC):	$79,330	Sum 1 through 8
INDIRECT OPERATING COSTS		
1. Overhead	$4,599	60% of Total Labor
2. Property Tax	$5,506	1% of TCC (avg national value)
3. Insurance	$5,506	1% of TCC (avg national value)
4. General Administrative	$11,011	2% of TCC (avg national value)
5. Capital Recovery Cost (7%, 30 years)	$44,400	CRF x TCC (OMB interest rate, estimated equipment life)
Total Capital Charges Costs (TCCC):	$71,022	Sum 1 thru 5
TOTAL ANNUALIZED OPERATING COSTS:	$150,352	TDOC + TCCC

TABLE 1
Radback Energy-OGS
Oakley, CA.
CO Catalyst Control Costs
CO and VOC Emission Summary

Controlled-Base Case		
CO Base Concentration-Controlled	2.0	ppm (BACT - CO Catalyst)
CO Annual Emission Rate	19.40	tpy
VOC Base Concentration-Controlled	1.00	ppm (BACT - CO Catalyst)
VOC Annual Emission Rate	11.1	tpy
Incremental Controlled Emissions Case		
CO Concentration	1.0	ppm (BACT w/ added CO Catalyst)
Annual Emission Rate:	9.70	tpy
VOC Concentration	0.80	ppm (BACT w/ added CO Catalyst)
Annual Emission Rate:	8.90	tpy
Incremental CO Reduction from Controlled Case:	9.70	tpy
Control Cost Effectiveness:	**$15,500**	per ton CO
Incremental VOC Reduction from Controlled Case:	2.2	tpy
Control Cost Effectiveness:	**$68,342**	per ton VOC

References:
1. OAQPS - OAQPS Cost Control Manual, 6th ED., November 2001, EPA 452/B-02-001.
2. Air Compliance Advisor, Version 7.5, 8-15-2003, EPA-OAQPS.
3. SATSOP CT Project, Phase II, SCA Amendment #4, Nov 2001.
4. Tesla Power Project, FPL, AFC Section 5.2, October 2001.
5. West County Energy Center, FPL, August 2005.
6. JEA-Greenland Energy Center, B&V, Sept 2008.
7. Vineyard Energy Center, Calpine, Utah DEQ, November 2003.
8. Marsh Landing GS project data scaled to OGS site.
9. BASF Proposal to OGS 1/11/10

Default escalation values derived from:
1. Wyoming DEQ/DAQ, BACT Cost Analysis Report, PR-Chapter 6, Section 2, O&G Production Facilities, 3/2010, per data supplied by J. W. Williams, Inc.

Table 2
BACT Summary for Small Auxiliary Boilers (May 2010)

Agency	Size Range, mmbtu/hr	NOx BACT	CO BACT	VOC BACT	SOx BACT	PM10/2.5 BACT	Comments
BAAQMD	33.5 - 50	9 – 25 ppm	100 ppm	GCP	Nat Gas	Nat Gas	NOx 9 ppm TFCE NOx 25 ppm AiP
	>50	7 – 9 ppm	10 – 50 ppm	GCP	Nat Gas	Nat Gas	NOx 7 ppm TFCE NOx 9 ppm AiP
SDAPCD	<50	12 ppm	ND	Nat Gas	Nat Gas	Nat Gas	PM 0.10 gr/dscf
	50 - 250	5-9 ppm	ND	Nat Gas	Nat Gas	Nat Gas	PM 0.10 gr/dscf
SCAQMD	<50	7 – 9 ppm	50 – 100 ppm	3 ppm	Nat Gas	Nat Gas	
	50 - 100	9 ppm	100-400 ppm	Nat Gas	Nat Gas	Nat Gas	
SJVUAPCD	<100	9 – 30 ppm	<400 ppm	.003 lb/mmbtu	Nat Gas	Nat Gas	
	100-200	9 – 15 ppm	ND	Nat Gas	Nat Gas	Nat Gas	
EPA RBLC*	20 - 100	9 – 300 ppm	10 – 400 ppm	0.02 – 0.002 lb/mmbtu	Nat Gas	Nat Gas	9 ppm NOx TFCE 9 ppm NOx AiP

ppm = values at at 3% O2 (dry) unless otherwise stated
TFCE = technologically feasible/cost effective
AiP = achived in practice
GCP = good combustion practices
ND = not determined or no data
*RBLC search criteria (boilers only, firing natural gas, 20-100 mmbtu hr, Process code 13.310, variable use rates).

TABLE 3
Radback Energy-OGS
Oakley, CA.
CO Catalyst Control Costs-Aux Boiler
CAPITAL COST SUMMARY

DIRECT CAPITAL COSTS (2010 $)		Explanation of Cost Estimates
		per Unit basis
1. Purchased Equipment:		Base Cost
A) Equipment Cost, EC	$115,000	Catalyst Cost to Control from 10 to 7 ppm
B) Auxiliary Equipment, AE	$0	Specify if applicable
B) Instrumentation & Controls	$11,500	10% of EC+AE
C) Freight	$5,750	5% of EC+AE
D) Taxes	$8,338	7.25% of EC+AE (California avg sales tax value)
Total Purchased Equip. Costs (TEC):	$140,588	Sum 1A thru 1E
2. Installation Costs:		
A) Foundation & Supports	$16,871	12% of TEC
B) Erection and Handling	$21,088	15% of TEC
C) Electrical	$1,406	1% of TEC
D) Piping	$2,812	2% of TEC
E) Insulation	$1,406	1% of TEC
F) Painting	$1,406	1% of TEC
G) Site Preparation	$7,029	5% of TEC
Total Installation Costs (TIC):	$52,017	Sum 2A thru 2G
Total Direct Capital Costs (TDCC):	$192,605	TEC + TIC
INDIRECT CAPITAL COSTS		
1. Engineering & Supervision	$14,059	10% of TEC
2. Construction and Field Exp.	$14,059	10% of TEC
3. Contractor Fees	$0	0% of TEC
4. Start-up	$1,406	1 % of TEC
5. Performance Testing	$1,406	1% of TEC
Total Indirect Capital Costs (TICC):	$30,929	Sum 1 thru 5
Total Direct & Indirect Capital Costs (TDICC):	$223,534	TDCC + TICC
Contingency Costs = 5%	$11,177	5% TDICC
TOTAL CAPITAL COSTS (TCC):	$234,711	TDICC + Contingency

TABLE 3
Radback Energy-OGS
Oakley, CA.
CO Catalyst Control Costs-Aux Boiler
ANNUAL OPERATING COST SUMMARY

DIRECT OPERATING COSTS (2010 $)		Explanation of Cost Estimates
		per Unit basis
1. Operating Labor	$11,340	1 hrs/day, $42/hr, 270 days/yr
2. Supervisory Labor	$1,701	15% of Operating Labor
3. Maintenance Labor	$5,670	0.5 hr/day, $42/hr, 270 days/yr
4. Maintenance Materials	$5,670	100% of Maintenance Labor
5. Electricity Expense	$0	not applicable
6. Catalyst Cost (replace/disposal)	$50,000	15 year lifespan and replacement
7. Ammonia Costs	$0	not applicable
8. Fuel Penalty (@ $0.005/scf)	$0	0.15% per inch backpressure, no fuel penalty assumed
9. Annualized Catalyst Cost	$5,490	CRF, 7%, 15 yrs, = 0.1098
Total Direct Operating Costs (TDOC):	$29,871	Sum 1 through 8
INDIRECT OPERATING COSTS		
1. Overhead	$11,227	60% of Total Labor
2. Property Tax	$2,347	1% of TCC (avg national value)
3. Insurance	$2,347	1% of TCC (avg national value)
4. General Administrative	$4,694	2% of TCC (avg national value)
5. Capital Recovery Cost (7%, 30 years)	$18,900	CRF x TCC (OMB interest rate, estimated equipment life)
Total Capital Charges Costs (TCCC):	$39,515	Sum 1 thru 5
TOTAL ANNUALIZED OPERATING COSTS:	$69,386	TDOC + TCCC

TABLE 3
Radback Energy-OGS
Oakley, CA.
CO Catalyst Control Costs-Aux Boiler
CO and VOC Emission Summary

** Based on the maximum use case of 4324 hrs/yr.*

Uncontrolled-Base Case		
CO Base Concentration-Uncontrolled	10.0	ppm (GCP w/no add-on controls)
CO Annual Emission Rate	0.798	tpy
VOC Base Concentration-Uncontrolled	5.00	ppm (GCP w/no add-on controls)
VOC Annual Emission Rate	0.229	tpy
Controlled Emissions Case		
CO Concentration	7.0	ppm (GCP w/CO Catalyst)
Annual Emission Rate:	0.559	tpy
VOC Concentration	3.00	ppm (GCP w/CO Catalyst)
Annual Emission Rate:	0.137	tpy
CO Reduction from Uncontrolled Case:	0.24	tpy
Control Cost Effectiveness:	**$290,318**	per ton CO
VOC Reduction from Uncontrolled Case:	0.1	tpy
Control Cost Effectiveness:	**$754,196**	per ton VOC

References:

1. OAQPS - OAQPS Cost Control Manual, 6th ED., November 2001, EPA 452/B-02-001.
2. Air Compliance Advisor, Version 7.5, 8-15-2003, EPA-OAQPS.
3. SATSOP CT Project, Phase II, SCA Amendment #4, Nov 2001.
4. Tesla Power Project, FPL, AFC Section 5.2, October 2001.
5. West County Energy Center, FPL, August 2005.
6. JEA-Greenland Energy Center, B&V, Sept 2008.
7. Vineyard Energy Center, Calpine, Utah DEQ, November 2003.
8. See attached text file on CO BACT summary data.

Default escalation values derived from:

1. Wyoming DEQ/DAQ, BACT Cost Analysis Report, PR-Chapter 6, Section 2, O&G Production Facilities, 3/2010, per data supplied by J. W. Williams, Inc.

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

APPLICATION FOR CERTIFICATION FOR THE *OAKLEY GENERATING STATION*

Docket No. 09-AFC-4
PROOF OF SERVICE
(Revised 5/13/2010)

APPLICANT

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DECLARATION OF SERVICE

I, Mary Finn, declare that on May 20, 2010, I served and filed copies of the attached (09-AFC-4) Oakley Generating Station Project Response to BAAQMD dated 5.20.10. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[http://www.energy.ca.gov/sitingcases/contracosta/index.html].** The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(C*heck all that Apply*)

For service to all other parties:

sent electronically to all email addresses on the Proof of Service list;

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_____ by delivering on this date, for mailing with the United States Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses **NOT** marked "email preferred."

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For filing with the Energy Commission:

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

OR

_____depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 09-AFC-4
1516 Ninth Street, MS-4
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I declare under penalty of perjury that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

Mary Finn