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Ms. Angela Hockaday
California Energy Commission
Docket Unit
1516 Ninth Street
Sacramento, CA 95814-5512

Subject:
APPLICATION FOR THE CANYON POWER PLANT
DOCKET NO. 07-AFC-09

Dear Ms. Hockaday:

Enclosed for filing with the California Energy Commission are one (1) original and twelve (12) copies of the following documents, for the Canyon Power Plant Docket No.07-AFC-09:

1. ECM Technology White Paper
2. Letter dated December 16, 2008 to SCAQMD
   Subject: Changes to the Canyon Power Plant Annual Emissions and Dispersion Modeling
3. Letter dated on January 6, 2009 to SCAQMD
   Subject: Change in the Fuel Use and Sox/PM10 Emission Factors Used During Commissioning for the Canyon Power Plant (Facility I.D. 153992)
4. Letter dated on January 23, 2009 to California Energy Commission
5. Letter dated on July 2, 2008
   Subject: May 8, 2008 Letter Regarding the AFC for Canyon Power Plant Project in Anaheim, CA.

Sincerely,

Scott Galati
Counsel to Canyon Power Plant

Executive Summary

EmeraChem (formerly Goal Line Environmental) submitted a proposal for the supply of Emission Control Modules (ECM) based on the utilization of the EMx / ESx catalyst systems (formerly SCONOX) for the SCPPA Canyon Power Plant (CPP) project. These ECMs would be an emission control system to be used in lieu of the planned ECM system based on SCR / CO catalysts with ammonia injection.

This white paper compares the proposed EMx / ESx systems to the more conventional SCR / CO systems being used in a simple cycle applications. The EMx / ESx technology is an emerging technology for the control of gas turbine emissions in combined cycle applications but has not been demonstrated in a simple cycle application which has a significantly higher turbine exhaust gas temperature around 840°F than the typical combined cycle operation temperature around 525°F. This higher temperature would necessitate the use of larger tempering air fans to cool the exhaust gas prior to the catalyst. Additionally, simple cycle units do not produce steam which is used as a carrier gas for the regeneration hydrogen (H_2) and as a consequence a small natural gas-fired packaged steam boiler would be part of the proposed EMx / ESx system equipment. The H_2 used in the regeneration cycle would be produced by two H_2 production units. While these various systems have been used individually, they have not been used together in a gas turbine simple cycle application and it would be expected that there would be a 'learning curve' period that would be necessary for system optimization and to ensure all systems work properly. At the CPP there will be four turbines and the plant will operate as a peaking facility. The use of the EMx / ESx system on all four units would compound any problems encountered with the new technology when compared to use on a single turbine unit.

A secondary issue concerns the need to generate and use steam as part of the EMx / ESx system. As mentioned previously, the steam would be generated using a packaged steam boiler that will burn natural gas as the fuel source. The exhaust stack from the packaged steam boiler will generate an additional amount of NOx, CO, VOCs, and PM-10 that will contribute to the plant air emissions which is undesirable. Also, from a cold plant startup condition, it will take a significant amount of time for the steam boiler to heat up and produce the necessary process steam which in turn is expected to lengthen the EMx system startup time when compared to the SCR system. This is estimated to take a minimum of one hour.

Even though the EMx / ESx technology removes NOx emissions without the use of ammonia, the guaranteed reduction benefit is for reduced PM10 and VOC emissions. The capital cost of the EMx / ESx system (from the turbine exhaust flange through stack) and the associated H_2 production units and packaged steam boiler including installation is estimated at $37 million dollars for all four units. This compares to an estimated installed cost of $16 million dollars for the more conventional SCR / CO ECM system.

For the EMx / ESx ECM system there is an overall reduction benefit in the cost of purchasing the required emission offsets that amount to approximately $4 million dollars. Therefore, the net additional capital cost increase for the EMx / ESx ECM system would be on the order of $17 million dollars essentially doubling the cost of the ECM systems the CPP project.

A focused Best Available Control Technology (BACT) finds that the SCR/oxidation catalyst and EMx / ESx systems are essentially equivalent in terms of controlling NOx, CO, SOx, VOC, and directly emitted $PM_{10}/PM_{2.5}$. In addition, while the EMx / ESx system has the advantage of zero ammonia emissions compared to the SCR/oxidation catalyst systems, this benefit is not cost-

effective. Based on these findings, along with reliability concerns and the limited application of the technology to the size of units proposed for CPP, the analysis concludes that the SCR/oxidation catalyst system is BACT for CPP.

At the current time the AFC for the CPP has been submitted to the CEC and the Application for the PTC/PTO permits has been submitted the SCAQMD. If the CPP were to change its ECM technology, then both permits would need to be revised and resubmitted placing the planned plant commercial operating date of July 2010 in jeopardy.

At this time it does not appear that the use of an ECM based on EMx / ESx technology warrants further consideration by SCPPA for use in the CPP project. If the technology were proven to have the same reliability as a SCR / CO catalyst system in a LM6000 simple cycle application and if the costs were more competitive, then the technology would warrant further consideration in the early stages of a project.

Project Description

The Canyon Power Plant (CPP) is a proposed simple-cycle power generation project that consists of a nominal 200-megawatt (MW) plant, using four natural gas-fired General Electric LM 6000PC Sprint combustion turbines. The proposed plant will be owned by the Southern California Public Power Authority (SCPPA), and the City of Anaheim (COA) will be the Project Manager and Operator once the plant is built.

The CPP will be located on approximately 10 acres of disturbed land located at 3071 East Miraloma Avenue within an industrial area of the COA. Main access to the CPP site will be at the southeast corner of the project site from East Miraloma Avenue. A second gated entrance will be accessible via East Miraloma Avenue with a third gate off the alley to the east of the site.

The CPP is strictly dedicated for power generation to serve the COA's retail customers. COA has had a deficiency in resources during the summer months in the past. With growing peaking needs in the immediate future and reliability requirements as part of the California Independent System Operator (CAISO), it is critical for COA to develop and construct the Canyon Power Project as soon as feasible. COA is on an aggressive path to have the facility available for service no later than the summer of 2010. The estimates for delay would cost as much as $25-$40 million per year of delay. As a result the output of the plant will be utilized vital resource to serve native load within the COA and to meet resource adequacy requirements imposed by the CAISO.

In addition to the four natural gas-fired GE LM 6000PC Sprint gas turbines, the plant will include generator step-up transformers (GSU's), a 69 kilovolt (kV) switchyard, onsite fuel gas compressors, a gas pressure control and metering station, a packaged chilled water system for combustion turbine engine (CTG) power augmentation with associated cooling tower, selective catalytic reduction system (SCR) emission control systems, and other associated plant infrastructure.

Reason for Technology Evaluation

This evaluation was under taken to assess the technical and economic feasibility of utilizing an alternative means of controlling the gas turbine emissions to meet the project requirements. The alternative emissions control technology evaluated is the use of an EMx system (formerly

SCONOx offered by Goal Line Environmental) offered by EmeraChem LLC. The EMx system can be expanded to include ESx catalyst which removes sulfur from the gas turbine exhaust stream extending the maintenance cycle for the EMx catalyst.

Emission Control Technologies Evaluated

A gas turbine exhaust emission control system based on SCR (Selective Catalytic Reduction) / carbon monoxide (CO) catalyst technology is proposed for the CPP. The CO catalyst oxidizes CO and a portion of the volatile organic compounds (VOC) in the exhaust gas into carbon dioxide (CO_2) with this converted CO_2 contributing an insignificant amount to the overall quantity of CO_2 in the exhaust stream. The SCR catalyst in the presence of ammonia will convert nitrogen oxides (NOx) in the exhaust stream into nitrogen (N_2) and water vapor. With this process, there is a small amount of ammonia which remains unreacted in the exhaust stream and is referred to as "ammonia slip". Aqueous ammonia (19% aqueous ammonia by weight) is stored on site in a bermed tank and pumped to the ammonia injection system where it is vaporized and sprayed upstream of the SCR catalyst thoroughly mixing with the exhaust gas prior to entering the catalyst modules.

The EMx catalyst system is a single catalyst system which removes both CO and NOx with the same catalyst arranged in a module consisting of several isolatable chambers (10 for the CPP). As the NOx passes through the EMx module it is trapped on the catalyst surface where it remains until regeneration occurs. Regeneration is achieved by isolating one of the chambers in the catalyst module (or 2 chambers for the CPP) and passing a reduced atmospheric carrier gas (steam for CPP) containing a small amount of hydrogen gas (H_2) over the NOx attached to the catalyst surface thereby releasing the NOx as N_2 and water vapor. This regeneration stream is then vented into the turbine exhaust duct downstream of the catalyst system and vented to atmosphere (or it can be sent to a condenser for steam (water) recovery).

There is a small amount of sulfur dioxide (SO_2) in the turbine gas and if left untreated the SO_2 will mask the EMx catalyst and require removal for chemical washing to regain effectiveness. The amount of SO_2 in the exhaust stream reaching the EMx catalyst is greatly reduced by the addition of a secondary catalyst system, ESx, upstream of the EMx catalyst. As the exhaust gases pass through the ESx catalyst, the SO_2 is trapped on the catalyst surface. The regeneration gas is passed first through the EMx catalyst and then through the ESx catalyst where the SO_2 is removed and exhausts with the regeneration gas.

As the exhaust gas passes through the catalyst modules both the CO and VOC in the turbine exhaust gas stream are oxidized by the EMx catalyst into CO_2 and water vapor. These are very small additions to total amount of CO_2 and water vapor already existing in the exhaust gas stream.

A regeneration gas is required by the EMx process used to remove the adsorbed NOx or SOx in a reducing atmosphere (to prevent oxidation). The EmeraChem proposed method of developing the regeneration gas is by the use of a H_2 gas generation system (for example a HGM 10000 unit) which produces a 99.9% pure H_2 stream. This unit uses electrical heaters to generate steam which reforms natural gas into H_2 and CO_2. This gas is then be blended with carrier steam to form the regeneration gas. For the CPP, steam for use as the carrier gas would need to be produced by a packaged steam boiler. It should be noted that the auxiliary steam boiler used to generate the steam needed for the EMx process will burn natural gas as the fuel source. Therefore, the steam boiler operation will contribute an additional amount of NOx, CO,

VOCs, and PM-10 air emissions as part of the project which is undesirable. Also, from a cold plant startup condition, it will take a significant amount of time for the steam boiler to heat up and produce the necessary process steam which in turn is expected to lengthen the EMx system startup time when compared to the SCR system.

Due to the nature of 2 out of the 10 catalyst chambers being in the regeneration cycle at any given time this would result in 20% of the duct cross sectional area being blocked. Whether this blockage would impact the effectiveness of the EMx or the ESx is unknown since there is no operational history of this type of catalyst system in an LM6000PC Sprint application. It is well known that each particular turbine has a unique and non-uniform exhaust temperature profile and it may require additional refinements to the EMx system to properly address these characteristics in order to achieve uniform emission reduction control.

An additional area of technology development will be to ensure that there is proper mixing of the turbine exhaust gases with the large quantity of tempering (cooling) air that will be required. The tempering air volume that will be needed is approximately 30% of the total volume of the exhaust gases. This large quantity of tempering air will need to be thoroughly mixed with exhaust gases in a relatively short distance to provide a homogenous gas mixture to the catalyst system for proper emission control.

Installation Area Requirements

The foot print of the ECM module for the SCR / CO system for the CPP project will have a an overall length of 75 feet from the turbine exhaust flange to the end of the stack and have a duct width of approximately 20 feet. Duct height is on the order of 32 feet. The ammonia injection skid adds 10 feet to the width.

For the EMx system proposed for the CPP project, the distance from the turbine flange to the outside of the stack is approximately 75 feet with a casing width on the order of 27 feet. Height of the casing is expected to be 57 feet above the ground while the catalyst service elevator would have a height of 70 feet above grade. The catalyst service elevator, stationary loading platform, and jib crane foundation would add an additional width requirement of approximately 40 feet.

Project Costs

Capital Costs

The CPP installed capital cost of the conventional SCR / CO catalyst system including ammonia tank, piping, controls, etc. is estimated to be approximately $4,100,000 per unit.

Based on budget estimates received from EmeraChem for an EMx / ESx emission control system, the capital cost of the equipment is estimated to be $8,234,000 per unit. The installed cost was estimated to be $9,370,000 per unit. This installed cost includes installation, commissioning, H2 generation equipment, controls, etc. and includes a credit for platinum value at the end of the catalyst useful life.

The increase in installed costs for the EMx system for the four units is estimated to be $21,080,000.

Operating Costs

The estimated annual SCR / CO system operating cost based on 1,000 turbine operating hours per year is $26,500 which includes lost revenue due to parasitic load burden as well as aqueous ammonia consumption. Assuming the SCR / and CO catalyst lasts no longer than the 5 year guarantee, the annualized catalyst replacement cost is estimated to be $322,000.

The estimated annual operating cost for the EMx system proposed is $141,000 that includes lost revenue due to parasitic load burden as well as natural gas consumption, but does not include any costs associated with "washing" the catalyst modules. Assuming the catalyst lasts no longer than the 5 year guarantee, the annualized catalyst replacement cost is $1,839,600 with credit for recoverable platinum. (Note that the loss of the platinum value alone is approximately $450,000 per year for the five year guaranteed life.)

Based on the cost data above, the expected annual operating cost increase for an EMx system is estimated to be $114,300 without consideration of catalyst replacement cost since both catalysts are expected to last well beyond the 5 year guaranteed life.

Permitting Costs

In the process of permitting the CPP the project is required to purchase air emission offsets, Emission Reduction Credits (ERC), for the SOx, PM_{10}, and VOC. These costs are a one time expenditure based upon the expected (and thus restricted by permit operating conditions) operating conditions as stipulated by the SCAQMD regulations. Additionally, there is an ongoing annual permit fee, Reclaim Trading Credits (RTC), for NOx, emissions.

For the SCR / CO ECM system these ERC project costs were estimated at:

SOx	$470,305
PM_{10}	$13,248,800
VOC	$53,540
Total project emission capital cost	$13,771,845

For the EMX system (& associated package boiler) these ERC project costs were estimated at:

	EMx	Packaged Boiler
SOx	$470,305	$12,587
PM_{10}	$9,273,600	$408,480
VOC	$26,770	$2,342
Total project emission capital cost	$9,970,675	$408,420

For the SCR / CO ECM system the RTC operating cost was estimated at:

NOx	$185,365

For the EMX system these RTC operating cost including steam boiler related costs was estimated at:

NOx	$191,000

Reduction in emission capital costs for using the EMx system is estimated to be $3,577,750.

Total project increase in capital costs for the EMx system accounting for reduced emission costs is estimated at $17,512,250.

Operating Parameters

The SCR / CO emission control system (ECM) has certain physical operating characteristics which directly or indirectly impact the facility's ability to function as a peaking power plant in an effective manner. One characteristic is the gas side pressure drop through the ECM which affects the amount of power the gas turbine can produce. Another consideration is the parasitic electrical power consumed by the ECM auxiliary equipment which prevents this power from being used by the utility customers. Chemical consumption by the ECM impacts operating costs and can influence the plant design to accommodate deliveries as well as environmental considerations. Finally, it is expected that the CPP will only operate during the hottest part of the day and normally be off line during nighttime hours. The ECM equipment must also be able to withstand the thermal cycling from maximum to minimum temperature imposed on the structure and catalyst on a daily basis (potentially several hundred start-stop cycles annually). The CPP will be using a SCR / CO catalyst system technology that can control the exhaust emissions to be within permit limits 35 minutes after the turbine is started.

The EMx emission control system is expected to have a backpressure of 10.5 inches of water column (inwc). This backpressure will be the same as the guaranteed backpressure for the SCR system. Since the EMx system operates at a lower catalyst temperature when compared to the SCR / CO system there is an additional amount of cooling air introduced and this equates to an increase of 30 kW in parasitic load for the cooling air fans.

The proposed means of supplying the carrier gas (steam) for the regeneration system is through the use of a standard packaged steam boiler with an approximate rating of 35,000 pounds per hour of steam. It is expected that this boiler could be up to full steam production in less than one hour. The H_2 system has a small storage tank that would provide sufficient H_2 to last over 2.5 hours while the H_2 system warms up which takes on the order of 2 hours to be a full H_2 output. Thus, the ability to meet the stack emission compliance within the required 35 minute time frame can not be met. There is no startup time operating experience with the EMx system in simple cycle operation and it is expected that the EMx system could reasonably reach stack compliance in approximately one hour due to the additional complexity of the steam generation system, hydrogen generation system, and associated control systems.

EmeraChem has proposed a condensate recovery system to recover the regeneration steam after it has passed through the catalyst chambers. This system would vent (into the ECM stack) about 10% of the steam containing the SO_2 captured in the regeneration cycle. Cooling water for the condenser would be sent to the chiller's cooling tower where it would be cooled. This would add about 40% increased duty to the cooling tower and increase plant water usage by about 19% (76 gpm). Water make up to the packaged boiler would be approximately 9 gpm or 2% increase in plant water usage for a total increase in water demand of 21%. Cooling water requirements for the H_2 generator would add a small additional water requirement to the cooling tower duty included above. The EMx system would require operating the plant chiller cooling towers even if the chillers are not needed to operate.

The EMX catalyst requires periodic "washing" to revitalize the catalyst by removing sulfur and other contaminants which fouls the catalyst over time. With the use of the ESx catalyst EmeraChem projects that removing and washing the catalyst should only need to occur once or twice a year. Since the use of EMx in a simple cycle application has not occurred this projected cycle time may differ from expectations. Additionally, EmeraChem has proposed that a 70 foot high elevator structure would be needed to facilitate the catalyst removal and replacement operations.

Industry Experience

The GE LM6000PC SPRINT combustion turbine generator which will be used at the CPP is the industry leader in its size range (50MW) with hundreds of units in operation worldwide and over 60 operating units in California alone. Over 50 of these units are simple cycle peaking units further establishing it as the leading choice for simple cycle peaking duty in power plants of 50MW or greater. All of these units installed in California would have an emission control system similar to the system proposed for the CPP. Newer installations would have lower emissions since as the SCR / CO system technology has matured, the designs are able to achieve lower emissions and is reflected in the low emissions that the ECM vendor has guaranteed for CPP. Operation of the SCR / CO catalyst system requires minimal operator intervention after commissioning and the ammonia storage system with the ammonia forwarding pumps are a proven established operating system within a power plant. The temperature of the CPP CTG exhaust gases exposes to the catalyst range of temperature from 710 to 860°F. The self-contained ammonia injection control system is provided by the SCR / CO system vendor. At the end of the catalyst life, the catalyst is replaced and the old catalyst returned to the catalyst supplier for recycling.

The EMx technology, initially developed in 1996, is currently being used in several installations throughout the country (4 total installations with two installations having two units installed) in cogeneration or combined cycle applications. These units range in size from 5 MW to 43 MW. A second 43 MW unit has been ordered for the City of Redding Power Plant facility (Alstom GTX100 gas turbine) in a combined cycle application. EmeraChem, formerly Goal Line Environmental, who now owns the EMx technology, has indicated that numerous changes have been made to the original design and that the current EMx design overcomes many of the operating difficulties experienced with the early designs. (This evolution would appear to be following the typical progression for an emerging technology.) There are currently no simple cycle projects that have ordered EMx systems nor are there any operating systems within the South Coast Air Quality Management District (SCAQMD).

The EMx system as proposed by EmeraChem would be utilizing two HGM 10000 units manufactured by H_2Gen to produce the H_2 required by the process. Based on H_2Gen's installation, only a single HGM 10000 has been installed to date although over a dozen smaller units of the same design have been installed. In the warm-up cycle these units are at design 100% output within two hours. A pressurized H_2 storage tank would provide the H_2 supply to the regeneration system until full production can be reached. While the H_2Gen HGM 10000 system appears to a successful entry into the H_2 generation market, it has not been applied in an EMx system application and it would be expected that normal first time integration issues would arise.

Best Available Control Technology (BACT)

A top-down Best Available Control Technology (BACT) analysis has been performed by Sierra Research and is attached.

Conclusions

At the current time, the CPP is several months into the plant formal permitting process through the CEC for the AFC (Application for Certification) and the SCAQMD PTC/PTO (Permit to Construct/Permit to Operate). To covert the ECM from an approved BACT technology (SCR / CO system) to a technology (EMx system) not currently listed as BACT for a simple cycle peaking plant would delay the issuances of the CEC certification and the SCAQMD PTC by an estimated 6 to 8 months. SCPPA currently has a contract with GE to supply the four turbine power islands (CTG, ECM, and CEM) for the CPP. This contracting path was pursued to hold one contracting entity responsible for the entire power island rather than issuing separate contracts for the CTG, ECM, and CEM. It is not clear whether GE would be willing to offer an ECM based on EMx technology as part of a complete power island package. GE is typically very conservative with their willingness to guarantee entire packages and this would be a departure from a proven technology (SCR / CO). As a minimum, the renegotiations with GE could jeopardize the equipment delivery needed to meet the plant desired commercial operation date of July 2010. An additional consideration is that Alstom (a competitor with GE in the LM6000 unit size range) is the licensee of the EMx technology for units in the 50 MW and larger range and GE may be hesitant to embrace a technology licensed by a competitor. Depending upon the final selection of regeneration carrier gas, the water consumption of the CPP may increase by as much as 20% possibly necessitating a renegotiation of the water supply contract with the Orange County Water District (OCWD). It is not expected that this would be a concern to OCWD.

While the EMx technology may have a proven record with smaller size combined cycle and cogeneration units, and a single 43 MW combined cycle unit, there are currently no simple cycle units in operation, therefore, it remains to demonstrate reliable operation in a functioning plant. There will always be new challenges to overcome with the first few installations of a new technology. Currently EMx is not considered BACT for LM6000 simple cycle operation although EmeraChem is trying to have the EMx accepted as BACT for both the CEC and SCAQMD. It is expected that it could take several months for the two organizations to review the latest information available and recognize EMx as BACT for simple cycle LM6000 operation. Based on the cost data and operational requirements provided by EmeraChem, the cost to the project to switch technologies at this time would on the order of $17 million without consideration for the impact to the existing contract with GE to supply the power islands which include the SCR / CO system.

Comparison for ECM technologies installed for SCPPA CPP LM6000 CTG

Area of comparison	SCR / CO system	EMx / ESx system
Technology feasible		
Simple Cycle LM 6000 units in California	> 50	0
Emissions (guaranteed per unit)		
NOx (ppmvd@ 15% O2)	2.3	2.3
VOC (ppmvd@ 15% O2)	2	1
CO (ppmvd@ 15% O2)	6	6
SOx (lbs per hour)	0.3	0.3
PM10 (lbs per hour)	3	2.1
Ammonia slip (ppmvd@ 15% O2)	5	0
Time to Achieve Stack Permitted NOx Level From Turbine Start	35 minutes	60 minutes (minimum)
Costs:		
Capital Costs		
Installation*	$16,400,000	$37,492,000
Emission offsets**		
Sox	$470,305	$482,902
VOC	$53,540	$29,167
PM10	$13,248,000	$9,682,080
Total Emission	$13,771,845	$10,194,149
Total Capital	$30,171,845	$47,884,149
Operating Costs		
Utilities		
Natural gas (MBtu / hr, HHV))	0	50.3
Water (gpm)	0	83
Parasitic power kW	572	736
Ammonia (gph)	46	0
Utilities cost (annual)	$26,515	$140,820
Emissions**		
NOx (RTCs)	$185,365	$191,052
Total	$211,880	$331,872
Long term catalyst replacement cost* (based on 5 yr life, both may last longer) annual allowance	$322,000	$1,839,600

Note: Basis for plant operating costs is 1,000 turbine hours per year.
* Credit for recoverable Platinum was included in EMx / ESx costs
** EMx / ESx emission costs include package boiler

EMISSIONS AND OFFSET REQUIREMENTS FOR CPP WITH PROPOSED EMISSION CONTROL SYSTEMS

Pollutant	Emissions (lb/year)	Credits	Offset Type	Unit Price		Cost	
SCR / CO system							
NOx	23,918	23,918	RECLAIM	$7.75		$185,365	annual cost
	(lb/day)						
PM_{10}	120	144	Priority Reserve	$92,000		$13,248,000	one time cost
	(tons/year)						
SO_x	2.7665	2.7665	ERCs or other mitigation	$170,000		$470,305	one time cost
ROG	2.677	2.677		$20,000		$53,540	one time cost
					Total one time cost	$13,771,845	
EMx / ESx system							
NOx	23,918	23,918	RECLAIM	$7.75		$185,365	annual cost
	(lb/day)						
PM_{10}	84	100.8	Priority Reserve	$92,000		$9,273,600	one time cost
	(tons/year)						
SO_x	2.7665	2.7665	ERCs or other mitigation	$170,000		$470,305	one time cost
ROG	1.3385	1.3385		$20,000		$26,770	one time cost
					Total one time cost	$9,770,675	
EMx / ESx system packaged natural gas boiler							
NOx	734	734	RECLAIM	$7.75		$5,687	annual cost
	(lb/day)						
PM_{10}	3.7	4.44	Priority Reserve	$92,000		$408,480	one time cost
	(tons/year)						
SO_x	0.074	0.074	ERCs or other mitigation	$170,000		$12,597	one time cost
ROG	0.117	0.117		$20,000		$2,342	one time cost
					Total one time cost	$423,420	

BACT Analysis for
NOx, SOx, and $PM_{10}/PM_{2.5}$ Emissions

Canyon Power Plant Project

BACT is defined in SCAQMD Rule 1302 as:

the most stringent emission limitation or control technique which:

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

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

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

Of these three "prongs" of the BACT definition, the first and third are generally controlling. This analysis will follow EPA's guidance for the preparation of "top down" BACT analyses focusing specifically on identifying emission limitations or control techniques that are achieved in practice and technically feasible.

A "top-down" analysis format, consistent with guidance provided in EPA's October 1990 Draft New Source Review Workshop Manual, has been used for the BACT analysis. That guidance lays out five steps for a top-down BACT analysis, as follows:

1. Identify all control technologies;
2. Eliminate technically infeasible options;
3. Rank remaining control technologies by control effectiveness;
4. Evaluate most-effective controls and document results; and
5. Select BACT.

This procedure is followed for each of the three pollutants evaluated in this analysis. BACT for emissions during startup is also addressed.

Control of Nitrogen Oxides

1. Identify All Control Technologies

There are three basic means of controlling NOx emissions from combustion turbines: wet combustion controls, dry combustion controls, and post-combustion controls. Wet and dry combustion controls act to reduce the formation of NOx during the combustion process, while post-combustion controls remove NOx from the exhaust stream. Potential NOx control technologies for combustion turbines are listed below.

- Wet Combustion Controls
  - Water injection
  - Steam injection
- Dry Combustion Controls
  - Dry low-NOx combustor design
  - Catalytic combustors (e.g., XONON)
- Post-Combustion Controls
  - Selective catalytic reduction (SCR)
  - EMx system (formerly SCONOx offered by Goal Line Environmental)

2. Eliminate Technically Infeasible Options

The performance and technical feasibility of available NOx control technologies are discussed in more detail below.

Wet Combustion Controls – Steam or water injection directly into the turbine combustor is one of the most common NOx control techniques for combustion turbines. These wet injection techniques lower the flame temperature in the combustor and thereby reduce thermal NOx formation. Water and steam injection have been in use on both oil- and gas-fired combustion turbines in all size ranges for many years, so these NOx control technologies are clearly technologically feasible and widely available.

Dry Combustion Controls – Combustion modifications that lower NOx emissions without wet injection include lean combustion, reduced combustor residence time, lean premixed combustion, and two-stage rich/lean combustion. The most advanced combination of combustion controls for NOx is referred to as dry low-NOx (DLN) combustors. DLN technology uses lean, premixed combustion to keep peak combustion temperatures low, thus reducing the formation of thermal NOx. Several turbine vendors have developed this technology for their engines, including the engine proposed for this project. This control technique is technically feasible. However, DLN combustors are not compatible

with wet combustion controls; either DLN or wet combustion controls can be used, but not both.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON. No turbine vendors, other than General Electric and Kawasaki, have indicated the commercial availability of catalytic combustion systems at the present time, and then only on small (<10 MW) turbines; therefore, catalytic combustion controls are not available for this specific application and are not discussed further.

Post-Combustion Controls – SCR is a post-combustion technique that controls both thermal and fuel NOx emissions by reducing NOx with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen. SCR is used in numerous combustion turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NOx combustion controls. Consequently, this technology is clearly technologically feasible and widely available.

The EMx system is a proprietary catalytic oxidation and absorption technology that uses a single catalyst for the removal of NOx, CO, and VOC. The catalyst simultaneously oxidizes NO to NO_2, CO to CO_2, and VOCs to CO_2 and H_2O, and adsorbs NO_2 molecules onto the catalyst surface where they are stored as nitrates and nitrites.

With regard to the installation of EMx systems on combustion turbine power plants, the EMx system has been installed at the Sunlaw Federal Cogeneration Plant in Vernon, California; the Wyeth BioPharma cogeneration facility (formally the Genetics Institute Facility) in Massachusetts; the Montefiore Medical Center cogeneration facility in the Bronx, New York; and the University of California at San Diego. In addition, an EMx system is installed at the Redding Power Plant in California. The Sunlaw facility uses a 23 MWe LM-2500 combustion turbine, the Wyeth BioPharma facility has two 5 MWe Solar combustion turbines, the Montefiore Medical Center uses a 5 MWe Solar combustion turbine, the University of California San Diego plant uses two 15 MWe SoLoNOx Titan 130S combustion turbines, and the Redding plant uses a 43 MWe Alstom combustion turbine. Therefore, this technology is technologically feasible and available.

Conclusion – Based on the discussions above, the following NOx control technologies are available and potentially technologically feasible for the proposed project:

- Water injection;
- Steam injection;
- Dry Low-NOx Combustors;
- Selective Catalytic Reduction; and
- EMx System.

3. Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies are ranked by NOx control effectiveness in Table 1.

Table 1
NOx Control Alternatives

NOx Control Alternative	Available?	Technically Feasible?	NOx Emissions (@ 15% O_2)	Environmental Impact	Energy Impacts
Water Injection	Yes	Yes	25-42 ppm	Increased CO/VOC	Decreased Efficiency
Steam Injection	Yes	Yes	15 – 25 ppm	Increased CO/VOC	Increased Efficiency
Dry Low-NOx Combustors	Yes	Yes	9-25 ppm	Reduced CO/VOC	Increased Efficiency
Selective Catalytic Reduction	Yes	Yes	>90% reduction 1 – 2.5 ppm	Ammonia slip	Decreased efficiency
EMx	Yes	Yes	>90% reduction 1 – 2.5 ppm	Reduced CO; potential reduction in VOC	Decreased efficiency

4. Evaluate Most-Effective Controls and Document Results

The proposed project is proposing to use water injection for combustion NOx control. While there may be some additional NOx control available with the use of dry low NOx combustors compared to water injection, with the proposed installation of after-combustion controls the proposed project will meet the most stringent NOx BACT level for this type of combustion turbine regardless of the type of combustion control used. Therefore, no further discussion of combustion control technologies is necessary.

The potential performance of SCR and EMx, insofar as NOx emission levels are concerned, is essentially equivalent. Both technologies have the potential to reduce NOx emissions by at least 90%, and differences between low NOx levels (1 ppm vs. 2 ppm vs. 2.5 ppm) appear, in the case of each technology, to be largely a function of catalyst size, turbine outlet NOx concentration, and compliance terms (e.g., averaging period and monitoring requirements). The principal differences between the two technologies are associated with whether the low emission levels proposed have been achieved in practice using these technologies, their cost-effectiveness in achieving these levels, and secondary environmental impacts.

Achieved in Practice Evaluation – The SCAQMD has established formal criteria for determining when emission control technologies should be considered achieved in

practice (AIP) for the purposes of BACT determinations. The criteria include the elements outlined below.

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

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

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

Each of these criteria is discussed separately below for SCR and for EMx.

SCR Technology – SCR has been achieved in practice at numerous combustion turbine installations throughout the world. There are several utility-scale combined cycle projects that limit NOx emissions to 2.5 ppm or less, including the Mountainview Power Plant in San Bernardino County, California; the Inland Empire Energy Center in Riverside County, California; and the Cosumnes Power Plant in Sacramento County, California. However, in order to examine SCR performance for a plant of similar size to the proposed Canyon Power Plant, the Donald Von Raesfeld combined cycle power plant in California was evaluated. The Donald Von Raesfeld plant consists of two combined cycle LM6000 combustion turbines that are equipped with steam injection and SCR systems and that are required to comply with a permitted NOx emission rate of 2.0 ppm, similar to the Canyon Power Plant.

A review of NOx continuous emissions monitoring (CEM) data obtained from the EPA's Acid Rain program website[1] for the Donald Von Raesfeld plant indicates a mean NOx level for the two units of approximately 1.6 ppm during the period from 2005 to 2007. Following the first year of operation, the units at the Donald Von Raesfeld plant have experienced only a few hours of non-compliance per year (fewer than 0.4% of the annual operating hours exceeded the NOx permit limit of 2.0 ppm). At the higher NOx limit of 2.3 ppm required for the proposed Canyon Power Plant, the CEM data show that the number of non-compliant hours drops to approximately 0.1% of the annual operating hours. Enclosed as Attachment 1 is a summary of the CEM NOx emission review for this facility. The experience at the Donald Von Raesfeld plant indicates the ability of the SCR system to consistently control NOx emissions to levels of 2.5 ppm and less.

An evaluation of the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.5 ppm and lower) using SCR technology is summarized below.

- Commercial Availability: SCR technology is available with standard commercial guarantees for NOx levels at least as low as 2 ppm. Consequently, this criterion is satisfied.

- Reliability: SCR technology has been shown to be capable of achieving NOx levels consistent with a 2.0 ppm permit limit during extended, routine operations of the Donald Von Raesfeld plant. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.

- Effectiveness: SCR technology has been demonstrated to achieve NOx levels of 2.5 ppm and less. At the Donald Von Raesfeld plant, short-term excursions have resulted in NOx concentrations above the permitted level of 2.0 ppm; however, these excursions have not been associated with diminished effectiveness of the SCR system. Rather, these excursions have been associated with SCR inlet NOx levels in excess of those for which the SCR system was designed.

- Conclusion: SCR technology capable of achieving NOx levels of 2.5 ppm and less is considered to be achieved in practice. The proposed permit limits for the proposed Canyon Power Plant include a NOx limit of 2.3 ppm. This proposed limit is consistent with the available data.

EMx Technology – EMx has been demonstrated in service in five applications: the Sunlaw Federal cogeneration plant, the Wyeth BioPharma cogeneration facility, the Montefiore Medical Center cogeneration, the University of California San Diego facility, and the Redding Power Plant. Because the combustion turbines at the first four facilities are much smaller than those proposed for the proposed Canyon Power Plant, this analysis focused on the performance of the EMx system at the Redding Power Plant. The

[1] Available at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=prepackaged.results

Redding Power Plant currently consists of a single combined cycle 43 MWe Alstom GTX100 combustion turbine with a permitted NOx emission rate of 2.5 ppm. There is a second 43 MWe unit under construction at the Redding Power Plant, but that unit has not begun operation.

A review of NOx continuous emissions monitoring (CEM) data obtained from the EPA's Acid Rain program website[2] indicates a mean NOx level for the unit of less than 1.0 ppm during the period from 2002 to 2007. After the first year of operation, the unit at the Redding Power Plant has experienced only a few hours of non-compliance per year (fewer than 0.1% of the annual operating hours exceed the NOx permit limit of 2.5 ppm). At the lower NOx limit of 2.3 ppm that will be requirement for the proposed Canyon Power Plant, the CEM data show that the number of non-compliant hours increases to approximately 0.2% of the annual operating hours. Enclosed as Attachment 1 is a summary of the CEM NOx emission review for this facility. The experience at the City of Redding Plant indicates the ability of the EMx system to consistently control NOx emissions to levels of 2.5 ppm and less.

Based on this information, the following paragraphs evaluate the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.5 ppm and lower) using EMx technology.

- Commercial availability: EmeraChem Power has offered standard commercial guarantees for the proposed Canyon Power Plant. Consequently, this criterion is satisfied.

- Reliability: As discussed above, based on a review of the CEM data for the Redding Power Plant the EMx system complied with the 2.5 ppm NOx permit limit with only a few hours each year of excess emissions (following the first year, only approximately 0.1% of the annual operating hours). However, this level of performance was not without some significant operating and reliability issues. According to a June 23, 2005 letter from the Shasta County Air Quality Management District[3] (see Attachment 2), repairs of the EMx system began shortly after initial startup and have continued during several years of operation. Redesign of the EMx system was required due to a problem with the reformer reactor combustion production unit that led to sulfur poisoning of the catalyst. In addition, the EMx system catalyst washings had to occur at a frequency several times higher than anticipated during the first three years of operation, which has resulted in substantial downtime of the combustion turbine. Since the Redding Power Plant is the most representative of all of the EMx-equipped combustion turbine facilities for comparison to the proposed Canyon Power Plant, the problems encountered at the Redding Power Plant bring into question the reliability of the EMx system for the proposed project.

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[2] Available at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=prepackaged.results

[3] Letter dated June 23, 2005 from Shasta County Air Quality Management District to the Redding Electric Utility regarding Unit 5 demonstration of compliance with its NOx permit limit.

- Effectiveness: The EMx system at the Redding Power plant has been able to demonstrate compliance with a NOx level of 2.5 ppm. However, the Redding Power Plant is the only EMx-equipped facility of a size similar to that of the proposed Canyon Power Plant. In addition, there are no peaker combustion turbine power plants equipped with EMx systems. Since peaker combustion turbine power plants like the proposed Canyon Power Plant undergo significantly more turbine startups than a baseload combined cycle plant like the Redding Power Plant, controlling NOx emissions is more of a challenge for these types of plants. Consequently, due to the lack of actual performance data, there is some question as to the effectiveness of the EMx systems on peaker plants like the proposed project.

- Conclusion: EMx systems are capable of achieving NOx levels of 2.5 ppm and less. However, the operating history at the Redding Power Plant does not support a conclusion that this technology is achieved in practice based on South Coast AQMD guidelines, due mainly to reliability issues.

5. Select BACT

Based on the above analysis, both SCR and EMx-based systems are considered, in general, to be technologically capable of achieving NOx levels of 2.5 ppm and less, given appropriate consideration to turbine-outlet NOx levels, catalyst volume (space velocity), and control system design. Based on this information, BACT for NOx is considered to be the use of either SCR or EMx systems to achieve NOx levels not higher than 2.5 ppm. The proposed Canyon Power Plant proposes to use SCR technology to meet a NOx level of 2.3 ppm. Consequently, the proposed project is consistent with BACT requirements.

Control of Sulfur Oxides

1. Identify All Control Technologies

Natural gas fired combustion turbines have inherently low SOx emissions due to the small amount of sulfur present in the fuel. With typical pipeline quality natural gas sulfur contents well below 1 grain/100 scf, the SOx emissions for natural gas fired combustion turbines are orders of magnitude less than oil-fired turbines. Firing by natural gas and the resulting control of SOx emissions have been used by numerous combustion turbines throughout the world. Due to the prevalence of the use of natural gas to control SOx emissions from combustion turbines, only an abbreviated discussion of post-combustion controls will be addressed in this section.

Post-combustion SOx control systems include dry and wet scrubber systems. These types of systems are typically installed on high SOx emitting sources such as coal-fired power plants. Post-combustion control systems for combustion turbines also include ESx catalyst systems. These systems trap the sulfur in the exhaust stream on an ESx catalyst. During a regeneration process, the sulfur is removed from the ESx catalyst and is either reintroduced back into the exhaust stream or sent to a sulfur scrubbing system. If the

sulfur removed from the ESx catalyst is reintroduced back into the exhaust stream, there is no SOx control associated with the system.

2. Eliminate Technically Infeasible Options

All of the control options discussed above are technically feasible.

3. Rank Remaining Control Technologies by Control Effectiveness

The typical SOx control level for a well-designed wet or dry scrubber installed on coal fire boilers ranges from approximately 70% to 90%[4] with some installations achieving even higher control levels. According to EmeraChem literature,[5] the ESx system is capable of removing approximately 95% of the SOx emissions from the exhaust stream of natural gas fired combustion turbines. With the sulfur scrubber option, during the regeneration cycle of the ESx system the sulfur captured on the ESx catalyst is sent to a sulfur scrubbing unit. A high efficiency sulfur scrubbing unit would achieve a control level similar to that of the wet/dry scrubbers discussed above.

4. Evaluate Most Effective Controls and Document Results

The use of low sulfur content pipeline natural gas has been achieved in practice at numerous combustion turbine installations throughout the world, and the use of this fuel minimizes SOx emissions. While it would be technically feasible to install some type of post-combustion control such as a dry/wet scrubber system or an ESx catalyst with a sulfur scrubber on a natural gas fired turbine, due to the inherently low SOx emissions associated with the use of natural gas these systems are not cost effective and regulatory agencies do not require them. Consequently, no future discussion of post-combustion SOx control is necessary.

5. Select BACT

Since the EMx system proposed for the Canyon Power Plant is not equipped with a regeneration combustion sulfur scrubber, there is no SOx control capability associated with this system. Therefore, the SOx emissions for the proposed project with or without the EMx system are identical. The SOx control method for the proposed Canyon Power Plant is the use of pipeline-quality natural gas. Consequently, the proposed project is consistent with BACT requirements.

Control of $PM_{10}/PM_{2.5}$ Emissions

[4] Air Pollution Control Manual, Air and Waste Management Association, Second Edition, page 206.
[5] High Performance EMx Emissions Control Technology for Fine Particles, NOx, CO, and VOCs from Combustion Turbines and Stationary IC Engines, by Steven DeCicco and Thomas Girdlestone, EmeraChem Power, June 2008, page 19.

1. Identify All Control Technologies

The proposed Canyon Power Plant combustion turbines will be fired by natural gas, which has inherently low directly emitted $PM_{10}/PM_{2.5}$ characteristics. The proposed combustion turbines will also emit the $PM_{10}/PM_{2.5}$ precursors SOx, VOC, and NOx. In addition, with the use of an SCR system the proposed project will emit ammonia, which is also a precursor to the formation of $PM_{10}/PM_{2.5}$.

With regard to directly emitted $PM_{10}/PM_{2.5}$ emissions, the guaranteed maximum hourly emission rates are very similar between the proposed SCR/oxidation catalyst control system and the proposed EMx system, with PM_{10} emission levels of 3.0 lbs/hr and 2.1 lbs/hr, respectively. This difference between the directly emitted $PM_{10}/PM_{2.5}$ emission levels for the SCR/oxidation catalyst system and the EMx system is most likely due to the compliance safety factor assumed in the vendor guarantees rather than a true difference in actual directly emitted $PM_{10}/PM_{2.5}$ emission levels. As an example, according to an EmeraChem document on the EMx system,[6] the actual PM_{10} emissions at the Redding Power Plant were approximately 2.0 lbs/hr. Since the Redding Power Plant combustion turbine is of a similar size to the units proposed for the Canyon Power Plant, the EMx system guarantee of 2.1 lbs/hr does not appear to include much of a compliance safety factor. In addition, due to the problems associated with the current EPA particulate source test method's ability to accurately measure particulate emissions from natural gas fired combustion turbines, it is expected that there will be very little difference in the actual measured PM_{10} emissions for the two control systems. An example of this problem with the EPA particulate source test method is shown by the test data summarized in Attachment 3. This data summarizes particulate emission test results for LM6000 natural gas fired combustion turbines for testing performed between 1995 and 2004. As shown by these data, particulate emissions for the same model combustion turbine vary from 0.05 lbs/hr to 13.08 lbs/hr. Consequently, the two control systems are equivalent with regards to this pollutant.

Regarding SOx emissions, as discussed above there is no difference between the SCR/oxidation catalyst system and the EMx system proposed for the Canyon Power Plant. Consequently, the two control systems are equivalent with regards to this pollutant.

Regarding NOx emissions, as with SOx emissions there is no difference between the SCR/oxidation catalyst system and the EMx system proposed for the Canyon Power Plant. Consequently, the two control systems are also equivalent with regards to this pollutant.

With regards to VOC emissions, the SCR/oxidation catalyst system proposed for the project has a guaranteed level of 2 ppm and the EMx system has a guaranteed level of 1 ppm. While at first this appears to be a significant difference between the two control

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[6] High Performance EMx Emissions Control Technology for Fine Particles, NOx, CO, and VOCs from Combustion Turbines and Stationary IC Engines, by Steven DeCicco and Thomas Girdlestone, EmeraChem Power, June 2008, page 7.

systems, these VOC emission levels are close to the detection level of typical EPA source test methods and therefore it is expected that there will be very little difference in the actual measured VOC emissions for the two control systems. Consequently, the two control systems are essentially equivalent with regards to this pollutant.

For ammonia, emissions will result from the use of ammonia-based NOx control technology such as a SCR system. Since a detailed discussion of NOx control systems is discussed above, only an abbreviated discussion of this technology is provided below.

2. Eliminate Technically Infeasible Options

The performance of SCR and EMx, insofar as NOx emission levels are concerned, has been discussed above.

3. Rank Remaining Control Technologies by Control Effectiveness

EMx results in no emissions of ammonia, while SCR results in ammonia slip levels of up to 5 ppm. The following discussion evaluates potential ammonia slip limits of 5 ppm and 0 ppm. The latter limit would be achievable, at the present time, only through the use of EMx technology.

4. Evaluate Most-Effective Controls and Document Results

SCR has been achieved in practice at numerous combustion turbine installations throughout the world. Ammonia slip associated with SCR system operation results from a gradual decline in catalyst activity over time, necessitating the use of increasing amounts of ammonia injection to maintain NOx concentrations at or below the design rate.

The parameters of NOx concentration, ammonia slip limit, and catalyst life are integrally related. That is, catalyst performance is generally specified as being a particular NOx concentration (e.g., 2.3 ppm), guaranteed for N years (e.g., 3 years), with a maximum ammonia slip level of X ppm (e.g., 5 ppm). Such a specification indicates that catalyst performance will degrade over time such that at the end of three years, ammonia slip will increase to not more than 5 ppm while maintaining NOx concentrations at or below 2.3 ppm. During the early period of performance, ammonia slip from an oxidation catalyst is typically less than 1-2 ppm, and will approach the guarantee level only towards the end of the catalyst life. EMx systems have the potential to achieve low NOx levels without any ammonia slip. Consequently, the following discussion compares the use of SCR with a 5 ppm ammonia slip level with EMx to meet comparable NOx levels, but without any ammonia slip.

SCR technology has been shown to be capable of achieving ammonia slip levels below 5 ppm over at least a three-year catalyst life period. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.

Since EMx technology to eliminate ammonia slip may be technologically feasible, a further evaluation of the cost-effectiveness of this technology was performed. In this analysis, the cost of an EMx system was compared with the cost of an SCR and oxidation catalyst system, with the incremental cost assigned to the benefit of eliminating ammonia slip emissions. (It is appropriate to make such an assignment because the performance of the SCR and oxidation catalyst systems is comparable to that proposed for the EMx system with respect to the remaining pollutant emission levels for the proposed Canyon Power Plant.)

As shown in Tables 2 through 4, the results of this analysis indicate that the incremental cost-effectiveness of the EMx system for the purpose of reducing ammonia emissions is approximately $375,000 per ton.

The South Coast AQMD no longer publishes cost-effectiveness criteria for use in performing BACT analyses for major sources (source emissions greater than 10 tons/year). In the absence of SCAQMD-specific criteria, the following values are presented to provide a reference for the calculated cost-effectiveness of EMx as an ammonia control device. Since ammonia is regulated as a precursor to PM_{10}, the values shown below represent the BACT cost-effectiveness thresholds for PM_{10}:

Bay Area AQMD	$ 5,300 /ton[7]
San Joaquin Valley Unified APCD	$11,400 /ton[8]

While these values are not, by themselves, determinative, they indicate that the cost-effectiveness of using EMx to eliminate ammonia emissions is well in excess of costs that are normally required for the control of PM_{10} in BACT determinations in areas of California that exceed the state and/or federal PM_{10} air quality standards.

5. Select BACT

Based on the above information, BACT for ammonia is considered to be an ammonia slip limit of 5 ppm. EMx has the potential to eliminate ammonia emissions; however, this candidate technology was rejected for the reasons discussed above. The Canyon Power Plant proposes to use SCR technology to meet an ammonia slip limit of 5 ppm in conjunction with a NOx level of 2.3 ppm. Consequently, the proposed project is consistent with BACT requirements for ammonia emissions.

Table 2
SCR/Oxidation Catalyst Costs
(total for four combustion turbines)

Total Capital Investment (equipment cost, installation cost, indirect costs)[a]	$16,400,000

[7] Bay Area AQMD BACT/TBACT Policy and Implementation Guidelines.
[8] San Joaquin Valley Unified APCD Revised BACT Cost Effectiveness Thresholds, May 14, 2008.

Capital Recovery Cost (assumed interest rate of 10% over period of 15 years results in cost factor of 0.1315)[b]	$2,156,600/year
Total Annual Costs (operating cost, maintenance costs, utility costs, indirect costs, does not include catalyst replacement costs)[a]	$26,515/year
Total Annualized Costs	$2,183,115/year

[a] ECM Technology White Paper, PB Power, July 2008
[b] From EPA/OAQPS Control Cost Manual, EPA-452/B-02-001, Table A.2, January 2002

Table 3 EMx System Costs (total for four combustion turbines)	
Total Capital Investment (equipment cost, installation cost, indirect costs)[a]	$37,492,000
Capital Recovery Cost (assumed interest rate of 10% over period of 15 years results in cost factor of 0.1315)[b]	$4,930,198/year
Total Annual Costs (operating cost, maintenance costs, utility costs, indirect costs, does not include catalyst replacement costs)[a]	$140,820/year
Total Annualized Costs	$5,071,018/year

[a] ECM Technology White Paper, PB Power, July 2008
[b] From EPA/OAQPS Control Cost Manual, EPA-452/B-02-001, Table A.2, January 2002

Table 4 Cost Effectiveness for Ammonia Emission Control	
EMx Annualized Costs	$5,071,018/year
SCR/Oxidation Catalyst Annualized Costs	$2,183,115/year
Incremental Annualized Costs	$2,887,903/year
Annual Ammonia Emissions with SCR/Oxidation Catalyst (total for four combustion turbines)[a]	7.7 tons/year
Annual Ammonia Emissions with EMx System (total for four combustion turbines)	0 tons/year
Reduction in Ammonia Emissions (total for four combustion turbines)	7.7 tons/year
EMx Cost Effectiveness ($/ton removed)	$375,052/ton

[a] Based on December 2007 Application for Certification for the Canyon Power Plant, Table 6.16-3.

BACT During Startup

1. Identify all control technologies

Startup and shutdown periods are a normal part of the operation of simple cycle power plants such as CPP. BACT must also be applied during the startup and shutdown periods of gas turbine operation. The BACT limits discussed in the previous section apply to steady-state operation, when the turbine has reached stable operation and the emission control systems are fully operational.

During gas turbine startup, the post-combustion controls that are used to achieve additional emissions reductions require specific exhaust temperature ranges to be fully effective. The use of SCR or EMx to control NOx is not technically feasible when the surface of the catalyst is below the manufacturer's recommended operating range. Therefore, the BACT determinations for NOx during normal, steady-state operation are not applicable during startup and shutdown.

2. Eliminate technically infeasible options

As discussed earlier, since the CPP is a peaking power plant, it is advantageous (necessary) for the add-on emissions control system to accommodate a 10-minute start cycle that can be achieved by the gas turbine. The SCR system can reduce turbine NOx emissions to meet the 2.3 ppmc permit limit within 35 minutes after the turbine is started.

The EMx literature states:

> "The thermal characteristics of the EMx technology allows for quick start-up of the emissions system. The low light off curves for destruction of ...NOx on the EMx catalyst provide for emissions control and compliance quickly after start-up."[9]

However, these curves have not been provided for review. Further, because the EMx system requires that each chamber be regenerated every 20 to 28 minutes, it appears that regeneration of at least two chambers would be required during the first hour of operation. The regeneration process requires steam as a carrier gas to carry the hydrogen regenerating gas to the chambers. The steam is generated in a small package boiler. Because the CPP units will be in peaking service, they may be shut down for days at a time and the package boiler would often be cold when the units are called upon to start up. The cold boiler would not be able to begin producing steam immediately—it could take up to an hour for the carrier steam to become available. As discussed earlier, it is unlikely that the EMx system would be able to bring the CPP units into compliance with the NOx limit within the required 35 minute time frame unless the boiler is started up 30 minutes or more before the turbine is started up or unless significant modifications are made to the proposed steam supply system. However, this is not possible at all times since the California ISO is not required to provide any lead time prior to dispatching the

[9] DeCicco, Steven, and Thomas Girdlestone, EmeraChem Power, "High Performance EMx™ Emission Control Technology for Fine Particles, NOx, CO, and VOCs From Gas Turbines and Stationary IC Engines," June 2008.

CPP in emergency situations. In all other situations the CPP will be provided with a minimum of a 45-minute lead time. . Either of these changes to the steam supply system would generate additional air pollutant emissions.

3. Rank remaining control technologies by control effectiveness

It appears that the SCR control technology would be able to achieve full emission control within 35 minutes but the EMx technology would require a longer time to achieve full emission control. Therefore, use of the EMx technology may result in higher emissions during startup for the proposed simple-cycle project.

4. Evaluate most-effective controls and document results

Use of the EMx technology would not appear to result in lower emissions during startup for the proposed simple-cycle project. It does not appear that EMx would be more effective than SCR in controlling emissions from the simple-cycle turbines during startup.

5. Select BACT

Use of the EMx technology would not appear to result in lower emissions than SCR technology during startup for the proposed simple-cycle project. Therefore, the project as proposed is consistent with BACT for startup emissions.

Attachment 1

Summary of NOx CEM Emissions Data

SUMMARY OF NOx CEM EMISSIONS DATA

Redding Power Plant NOx CEM Emissions Data Summary							
Year	No. of Operating Hours[a]	No. of Valid Operating Hours[b]	Number of Turbine Starts	Mean Hourly NOx Emission Rate, ppm[c]	Max. 1-hr Average NOx Emission Rate, ppm	Percent of Hours Exceeding 2.3 ppm[c]	Percent of Hours Exceeding 2.5 ppm[c]
2002	2,555	2,490	13	0.83	5.36	2.3%	1.0%
2003	7,301	7,220	16	0.96	11.43	0.5%	0.1%
2004	6,345	6,250	23	0.94	7.93	0.2%	0.1%
2005	6,684	6,580	23	0.61	15.85	0.1%	0.1%
2006	6,253	6,220	6	0.53	14.48	0.1%	0.1%
2007	5,143	5,074	14	0.69	2.49	0.1%	0.0%

Notes:
a. Total number of CTG operating hours.
b. Total number of operating hours excluding startup/shutdown and low-load operation.
c. All concentrations expressed as ppmvd corrected to 15% O_2.
d. Exceedance frequency as percent of valid operating hours, excluding startup/shutdown and low-load operation.

Donald Von Raesfeld Power Plant NOx CEM Emissions Data Summary							
Year	No. of Operating Hours[a]	No. of Valid Operating Hours[b]	Number of Turbine Starts	Mean Hourly NOx Emission Rate, ppm[c]	Max. 1-hr Average NOx Emission Rate, ppm	Percent of Hours Exceeding 2.0 ppm[c]	Percent of Hours Exceeding 2.3 ppm[c]
Unit 1							
2005	3,344	2,617	166	1.63	15.72	0.8%	0.7%
2006	3,608	2,688	211	1.61	9.51	0.2%	0.1%
2007	5,667	4,834	183	1.61	8.99	0.1%	0.1%
Unit 2							
2005	3,195	2,483	163	1.58	14.87	1.2%	1.0%
2006	3,916	3,083	201	1.62	8.80	0.4%	0.1%
2007	5,694	4,893	185	1.61	7.10	0.1%	0.1%

Notes:
a. Total number of CTG operating hours.
b. Total number of operating hours excluding startup/shutdown and low-load operation.
c. All concentrations expressed as ppmvd corrected to 15% O_2.
d. Exceedance frequency as percent of valid operating hours, excluding startup/shutdown and low-load operation.

Attachment 2

June 23, 2005 Letter from
Shasta County Air Quality Management District

Shasta County

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

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

June 23, 2005

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

Dear Mr. Bennett:

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

Ross Bell

Ross Bell
Air Quality District Manager

RB/dd

Attachment 3

Summary of PM Test Results
LM6000 Combustion Turbines

LM6000 Combustion Turbine PM Test Result Summary - Natural Gas Fired Units

Project Name	Unit Name	Test Date	Turbine	Nominal Rating	Measured PM (lbs/hr) Probe Catch	Filter Catch	Total F/H	Total B/H	Total
Gilroy Energy	1	4/26/02	LM6000	48 MW	0.02	0.00	0.02	0.02	0.05
SMUD/SCA	A	3/19/97	LM6000	43 MW			0.13	0.08	0.21
Gilroy Energy	1	4/26/02	LM6000	48 MW	0.00	0.00	0.00	0.34	0.34
Almond Power Plant	1	11/19/03	LM6000	49 MW	0.00	0.00	0.00	0.39	0.39
Almond Power Plant	1	11/19/03	LM6000	49 MW	0.00	0.00	0.00	0.49	0.49
Gilroy Energy	1	4/26/02	LM6000	48 MW	0.00	0.02	0.02	0.47	0.50
Carson IceGen	2	9/13/95	LM6000	43 MW					0.55
Goosehaven	1	3/26/04	LM6000	49 MW	0.15	0.05	0.20	0.35	0.55
Carson IceGen	2	9/14/95	LM6000	43 MW					0.63
Almond Power Plant	1	8/26/04	LM6000	49 MW	0.14	0.01	0.15	0.49	0.64
Gilroy Energy	2	5/1/02	LM6000	48 MW	0.40	0.00	0.40	0.28	0.68
Carson IceGen	2	9/13/95	LM6000	43 MW					0.70
Gilroy Energy	3	4/25/02	LM6000	48 MW	0.00	0.00	0.00	0.75	0.75
Carson IceGen	1	9/18/95	LM6000	43 MW					0.78
Gilroy Energy	2	5/1/02	LM6000	48 MW	0.31	0.00	0.31	0.47	0.78
Gilroy Energy	3	4/25/02	LM6000	48 MW	0.00	0.02	0.03	0.81	0.83
Almond Power Plant	1	8/25/04	LM6000	49 MW	0.03	0.00	0.04	0.83	0.87
Carson IceGen	2	11/1/96	LM6000	43 MW			0.36	0.52	0.88
SMUD/SCA	A	3/20/97	LM6000	43 MW			0.23	0.66	0.89
Carson IceGen	1	10/6/95	LM6000	43 MW					1.05
SMUD/SCA	A	3/11/98	LM6000	43 MW			0.81	0.24	1.05
Carson IceGen	1	10/6/95	LM6000	43 MW					1.09
Riverview	1	7/27/04	LM6000	49 MW	0.26	0.26	0.52	0.57	1.09
Creed	1	3/27/04	LM6000	49 MW	0.55	0.00	0.55	0.55	1.10
Goosehaven	1	3/26/04	LM6000	49 MW	0.13	0.21	0.34	0.81	1.15
Almond Power Plant	1	11/19/03	LM6000	49 MW	0.00	0.01	0.01	1.16	1.17
SMUD/SCA	B	3/17/97	LM6000	43 MW			0.17	1.04	1.21
Almond Power Plant	1	8/25/04	LM6000	49 MW	0.24	0.01	0.24	0.97	1.22
Goosehaven	1	3/29/04	LM6000	49 MW	0.62	0.00	0.62	0.62	1.25
SMUD/SCA	B	3/18/97	LM6000	43 MW			0.21	1.08	1.29
SMUD/SCA	B	3/13/98	LM6000	43 MW			0.96	0.42	1.38
Creed	1	3/27/04	LM6000	49 MW	0.71	0.00	0.71	0.71	1.41
Los Esteros	1	3/16/03	LM6000	49 MW	0.89	0.44	1.33	0.12	1.45
Los Esteros	4	3/12/03	LM6000	49 MW	1.03	0.07	1.10	0.36	1.46
Lambie	1	3/26/04	LM6000	49 MW	0.98	0.00	0.98	0.49	1.47
Los Esteros	3	3/14/03	LM6000	49 MW	0.54	0.16	0.70	1.10	1.80
Goosehaven	1	3/29/04	LM6000	49 MW	1.05	0.00	1.05	0.79	1.84
SMUD/SCA	A	3/11/98	LM6000	43 MW			1.32	0.53	1.85
SMUD/SCA	B	3/12/98	LM6000	43 MW			1.65	0.20	1.85
Riverview	1	7/27/04	LM6000	49 MW	0.27	0.27	0.54	1.35	1.89
Los Esteros	2	3/15/03	LM6000	49 MW	1.45	0.12	1.57	0.35	1.92
Lambie	1	3/26/04	LM6000	49 MW	0.98	0.00	0.98	0.98	1.97
Riverview	1	7/27/04	LM6000	49 MW	0.26	0.26	0.51	1.46	1.97
Lambie	1	3/26/04	LM6000	49 MW	1.25	0.00	1.25	0.75	2.00
SMUD/SCA	A	3/11/98	LM6000	43 MW			1.66	0.35	2.01
SMUD/SCA	B	3/12/98	LM6000	43 MW			0.77	1.34	2.11
Goosehaven	1	3/29/04	LM6000	49 MW	0.61	0.00	0.61	1.51	2.12
Creed	1	3/27/04	LM6000	49 MW	0.55	0.00	0.55	1.66	2.21
Gilroy Energy	2	5/1/02	LM6000	48 MW	0.33	0.00	0.33	2.13	2.46
Los Esteros	1	3/16/03	LM6000	49 MW	0.46	0.18	0.64	1.82	2.46
Gilroy Energy	3	4/25/02	LM6000	48 MW	0.55	0.00	0.55	2.05	2.60
Los Esteros	3	3/14/03	LM6000	49 MW	0.02	0.59	0.61	2.13	2.74
Los Esteros	2	3/15/03	LM6000	49 MW	1.18	0.30	1.48	1.27	2.75
Los Esteros	4	3/13/03	LM6000	49 MW	0.96	0.52	1.48	1.40	2.88
Los Esteros	4	3/12/03	LM6000	49 MW	0.92	0.70	1.62	1.29	2.91
Los Esteros	3	3/14/03	LM6000	49 MW	1.37	0.07	1.44	1.52	2.96
Los Esteros	2	3/15/03	LM6000	49 MW	0.97	0.16	1.13	2.09	3.22
Los Esteros	1	3/16/03	LM6000	49 MW	1.26	0.26	1.52	1.95	3.47
SMUD/SCA	B	2/6/97	LM6000	43 MW			2.04	1.70	3.74
Goosehaven	1	3/26/04	LM6000	49 MW	0.31	0.05	0.37	3.40	3.77
SMUD/SCA	B	3/12/98	LM6000	43 MW			3.20	0.77	3.97
SMUD/SCA	A	2/4/97	LM6000	43 MW			1.44	2.89	4.33
Goosehaven	1	2/27/04	LM6000	49 MW	1.39	0.00	1.39	3.06	4.45
Goosehaven	1	2/27/04	LM6000	49 MW	1.63	0.00	1.63	2.99	4.62
SMUD/SCA	A	3/19/97	LM6000	43 MW			3.70	1.07	4.77
Goosehaven	1	2/27/04	LM6000	49 MW	1.67	0.00	1.67	3.62	5.30
Lambie	1	2/26/04	LM6000	49 MW	1.29	0.00	1.29	4.14	5.43
Carson IceGen	2	11/1/96	LM6000	43 MW			1.94	4.11	6.05
SMUD/SCA	B	2/18/97	LM6000	43 MW			3.99	2.11	6.10
Lambie	1	2/26/04	LM6000	49 MW	1.39	0.00	1.39	4.72	6.11
Lambie	1	2/26/04	LM6000	49 MW	1.10	0.00	1.10	5.48	6.58
Creed	1	2/24/04	LM6000	49 MW	1.08	0.00	1.08	5.95	7.03
Creed	1	2/24/04	LM6000	49 MW	2.46	0.00	2.46	6.83	9.29
Creed	1	2/23/04	LM6000	49 MW	2.78	0.00	2.78	10.30	13.08

EmeraChem Power™
YOUR POWER. OUR PERFORMANCE.

Proposal to:

PB Power
City of Anaheim
GE-LM 6000

For an

EMx™ NOx Trap
Multi-Pollutant Emission Reduction Systems

Proposal #PB Power-City of Anaheim-LM 6000-07102008

July 10, 2008

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1 EXECUTIVE SUMMARY

EmeraChem is pleased to provide this proposal for the design, manufacture and delivery of the EMx™ NOx Trap, Multi-Pollutant Emission Reduction System for a natural gas fired GE LM-6000 turbine for simple cycle application.

Due to its ultra-clean emission performance, EMx™ minimizes emissions to the local community, minimizes the need for emissions offsets, minimizes project development costs for emissions fees, and allows power plant operators additional operational flexibility.

This proposal is for an EMx™ System guaranteed to reduce NOx from 25 ppmvdc to 2.32 based when operating on natural gas. Carbon monoxide (CO) will be reduced by 80%, volatile organic compounds (NMNEHC) will be reduced by 80% and PM will be reduced by 30%.

The system is configured with a modular design and limited ancillary equipment resulting in a straightforward, time saving installation.

EMx™ catalyst is a Platinum Group Metal (PGM) catalyst. This PGM is a true asset value on the plant site. At the end of its service life, the catalyst can be reprocessed to reclaim these PGMs to recover their cash value or reuse them in the manufacture of replacement catalyst.

TECHNOLOGY DESCRIPTION

1.1 Process Description

Refer to P&IDs. These are general in nature and may be modified in the final design of this project.

1.1.1. *EMx™ Catalytic Process*

The EMx catalyst technology treats combustion exhaust gases from sources such as combustion turbines, reciprocating engines, and boilers. The multi-pollutant catalyst system removes NOx, CO, VOCs, and ultrafine particulate matter (PM2.5). In addition, the system can be designed to contain a sulfur removal plant that will effectively remove sulfur from the concentrated regeneration gas stream.

The EMx catalyst technology performs in the operating temperature range of 425 to 750°F. Best economy and lowest pressure drop are achieved in the temperature range of 550 to 650°F where the catalyst activity is highest and the catalyst volume is minimized. In a simple cycle application, this optimal catalyst operating temperature is achieved by blowing cold outside air into the exhaust stream or adding an air to air exchanger to cool it to the optimum temperature.

This EMx™ reactor system has 10 catalyst chambers stacked vertically. Eight of the catalyst chambers treat combustion gas while the two are being regenerated using a reducing gas in an oxygen free environment. As the engine exhaust passes through the catalyst, CO is oxidized to carbon dioxide, hydrocarbons are oxidized to carbon dioxide and water vapor, and NOx is reacted with surface of the catalyst where it is bound as a solid carbonate.

Each chamber is equipped with a reliable, heavy duty, high-temperature isolation damper on the inlet and outlet of the chamber. The chamber undergoing regeneration is isolated from engine exhaust gases by closing its inlet and outlet isolation dampers.

A timer controls the length of the regeneration cycle. A regeneration cycle typically is set at 5 to 7 minutes, so that each section is in the oxidation/absorption cycle for four cycles (twenty to twenty-eight minutes). When the regeneration cycle has been completed the inlet and outlet isolation dampers open, the dampers on the next chamber close, and the regeneration cycle begins again.

1.1.2. *Regeneration Gas Production and Distribution*

The reducing gas required for regenerating the EMx™ and ESx™ catalyst is produced by a hydrogen generator system. This process has the simplicity, reliability, and operability needed for simple cycle operations. The hydrogen generator will be used in combination with a carrier of saturated steam. Steam will be produced utilizing a package boiler.

The flow rate of regeneration gas is approximately 1% of the engine's volumetric exhaust flow rate. The hydrogen generator uses RO/DI water, electricity and natural gas to produce high purity hydrogen. This hydrogen is then combined with saturated steam to create the regeneration gas.

Because one chamber is always in the regeneration cycle, the production of regeneration gas proceeds at a constant rate.

From the mixing vessel, the regeneration gas flows into a vertical piping header that connects to each of the ten reactor chambers via Class-6, leak-tight block valves assure that the regen gas is directed to the chamber being regenerated.

The regeneration system utilizes EmeraChem's improved and proven "push-pull" design. In the push-pull configuration, regeneration gas is injected between the last row of EMx catalyst and closed outlet isolation damper. The regen gas is distributed evenly across the catalyst surface. The regeneration gas flows upstream through all the catalyst and exits upstream of ESx catalyst, between the closed inlet isolation damper and the ESx catalyst. The entire regeneration cycle is carried out in one flow direction.

As the regeneration gas passes through the catalyst, the catalyst is regenerated. The reducing nature of the regeneration gas displaces engine exhaust and oxygen from the catalyst gas environment. When the oxygen has been depleted the hydrogen reacts with the catalyst surface, the nitrates are reduced to elemental gaseous nitrogen and released from the catalyst surface, and the catalyst NOx storage sites are freed for the next sorption cycle. Similarly, the ESx catalyst SOx storage sites are freed and the stored sulfur is released as SO_2.

The spent regen gas leaving the catalyst exits the reactor chamber through another block valve and into a spent regen gas vertical piping header. A rugged, high-temperature, variable speed induced draft blower draws the spent regen gas through the reactor and discharges it back into the exhaust duct downstream of the EMx reactor where it joins the treated engine exhaust. The blower speed and suction are controlled by the pressure in the chamber being regenerated. This pressure control loop provides conditions that minimize the leakage of regen gas out of the chamber and the leakage of exhaust gas into the chamber.

There are two process options for treating the spent regen gas. If it is not desired to remove sulfur the regeneration exhaust gas can be directed back into the exhaust downstream of the EMx catalyst. In the case of sulfur removal, the exhaust will be directed into a condenser recover the steam in the spent regen gas this further concentrating the SO_2 the scrubber

2.1.3 *Optional Steam Recovery Process Description*

Please refer to attached P&IDs. The optional steam condensing system will be located downstream of the regen exhaust blower. The facility's boiler makeup water will be used as the medium for condensing the exhaust gas. Makeup water requirements are approximately 10% by weight of the saturated steam. As example, 8,500 lb/hr of saturated steam would require approximately 1.7 GPM water flow to the condenser. Most of this saturated steam would be recovered as condensate water.

In the condenser the steam will be converted from gas to liquid, using a cooling water source or an air cooled heat exchanger. The recovered condensate will drain into a small receiver and be pumped back to the facility condensate collection system. The remaining non-condensables and approximately 10% steam that are not recovered flow into the downstream exhaust duct. See attached block diagram.

1.2 Equipment

1.2.1. *EMx™ Reactor Assembly*

The EMx™ reactor will have ten catalyst chambers stacked one above another. Between each chamber are two internal plena. One distributes regeneration gas from the supply header pipe to the downstream end of the chamber where it is injected during catalyst regeneration. The other plenum collects spent regeneration gas from the upstream end of the chamber and delivers it to the spent regen gas header pipe. Each reactor chamber has a catalyst access door used to load and unload catalyst modules.

The reactor will be constructed of carbon steel and designed for outdoor operation. External insulation for energy efficiency and personnel protection will be by others.

The approximate dimensions of each chamber will be as follows: 28 ft wide, 8 ft deep and 42 inches tall for a total reactor height of approximately 50 ft. The weight of catalyst in the reactor will be approximately 83,000 pounds.

Each reactor chamber will be equipped with louver dampers on the inlet and outlet to isolate the chamber from turbine exhaust during the periodic regeneration cycle. Durable high-temperature metallic seals minimize leakage and provide a controlled atmosphere for catalyst regeneration. Alloy sealing strips on the isolation louvers provide a durable and effective barrier against leaks during operation. The metallic seals require virtually no maintenance, in contrast to tadpole-type fabric gaskets. Design details of these isolation dampers are described below.

FRAME: The damper frame will be constructed of structural steel channel and plate. The frame will be designed to resist all loads imposed by shipping, handling and installation, as well as resist all loads imposed by operating conditions.

BLADES: The blades will be of a reinforced single cap design aerodynamically shaped to minimize pressure loss. Blade deflection will be less than L/360 at operating pressure to assure blade integrity. Blade moment of inertia and section modulus will be based on the actual blade cross section for determining deflection and stress. Thermal growth will be controlled by thrust collars, making the blade, in effect, "free floating". The blades will be sized to absorb thermal expansion without binding or interference.

SHAFTS: The blade shafts will be of 304 stainless steel for long bearing and packing life. The stub shafts will be welded to the blade to form a uniform axle with the blade and stiffener. Each damper will have an external blade indicator to show blade orientation.

BEARINGS: The bearings will be pedestal mounted, permanently lubricated and self aligning sleeve bearings. The bearings will be located adjacent to the packing to minimize deflection. Each shaft penetration will have a ductile iron-packing gland holding 3 rings of carbon graphite packing.

DRIVE: The drive will employ a bank of heavy duty pneumatic actuators directly coupled to the damper shafts. The drive will be capable of twice the required torque.

PERIPHERY SEALS: The louver dampers will have WahlcoMetroflex, Inc. Flex Ledge seals. The "Flex Ledge" seal will consist of flexible metal spring seals that contact the blade in the closed position. These seals will be located along the dampers vertical walls in an area less subject to abrasion and corrosion. The periphery mounted "Flex Ledge" seals will be constructed of alloy Inco 625 material. These fully self adjustable seals contact the blade in the closed position with metal to metal contact and allow thermal growth to be absorbed within a wide range of thermal conditions. These seals will be self adjusting to take up blade expansion and misalignment. The top and bottom of the blade periphery will have WahlcoMetroflex, Inc. tip seals. These seals employ Inco 625 spring seals to provide a resilient seat for a conventional high temperature seal.

1.2.2. *Regeneration Gas Production, Distribution and Manifold/Piping system*

HYDROGEN GENERATOR: The proposed solution is one of the lowest cost H2 generation systems available in the marketplace. Consisting of modular units that can be linked together or operated on a stand alone basis, the system can easily be expanded by adding additional units. Two HGM-10000 units will be provided that have the capacity to handle 20,000 scfh of 99.9% pure hydrogen.

The units are assembled at the factory and can often be installed within less than three weeks at your site. For installation, only a flat concrete foundation is required. Installation costs are very low compared to standard stick built plants.

The units are designed for continuous operation with one day maintenance every 3 months. WinCC Software platform and Siemens PLC Hardware are used for monitoring and control. Each unit has an integrated Human Machine Interface (HMI) touch panel screen. If connected to a Local Area Network (LAN), the HMI can be accessed from any PC within the LAN. The operator can remotely view and control the HGM via the remote HMI and access data logs in a non proprietary format. Data may be accessed via common industrial field buses such as ProfiBus and can be logged in logged in CSV file. All equipment is newly manufactured equipment and has an expected 15+ year service life, as maintained according to Operating Maintenance Manuals.

PIPING: Steam piping and valves are 304 stainless steel rated for the available steam temperature. Natural gas piping and valves are carbon steel.

The header and valves that supplies regeneration gas to each reactor chamber are 304 stainless steel. The spent regeneration gas header and valves are carbon steel. Expansion joints will be installed to allow for thermal expansion during heat-up.

Each reactor catalyst chamber will have one Class 6 inlet regeneration gas supply valve and a special internal flow distribution system to distribute regeneration gas evenly across the full face of the catalyst. Each chamber will also have one outlet valve for spent regeneration gas. See attached typical P&ID drawing.

1.2.3. *Control System*

The control system will utilize a "stand alone" programmable logic controller (PLC) with operator inputs made from a HMI panel. This controller is programmed to control all essential EMx™ functions, including opening and closing of reactor isolation dampers and regen gas inlet and outlet valves, measuring and controlling the mass flow rate of steam and hydrogen flow, controlling the speed of the VFD blower to maintain catalyst chamber

pressure during the regeneration cycle, displaying permissives, alarms, and first-out indication. The control system will be located at the regeneration gas system and will be shipped pre-wired to the I/O on the reformer skid. From the HMI the operator will be able to change set points, such as pressures, regeneration cycle times, and flow rates. Buyer supplies all interconnecting wiring and conduit between control panel and the instruments and actuators on the reactor and header pipes.

As options, the system can be remotely monitored by the use of modem, or share signals with other plant control systems.

1.3 Catalyst

The system will utilize EmeraChem's improved EMx™ catalyst. The EMx catalyst has higher NOx sorption capacity than previous formulations which translates into lower emissions and longer operating times between washings.

EMx™ and ESx® are platinum-based catalysts applied to a ceramic substrate. The precious metals in these catalysts are a valuable plant asset that can be recovered when the catalyst has reached the end of its service life. The ceramic catalyst blocks are housed in 304 stainless steel modules that provide structural rigidity and ease of handling. The specific dimensions of the modules, the number of modules, and number of rows of modules are based upon the reactor size, turbine exhaust gas composition, and performance requirements.

For this application the ceramic catalyst blocks will be contained in strong 24W"x42H" stainless steel modules to facilitate handling (the depth of ESx catalyst modules will be 5"; the depth of EMx catalyst modules will be 4". Each of the reactor's catalyst chambers will house one (1) row of ESx catalyst modules standing fourteen (14) modules across, and three (3) rows of EMx catalyst modules standing fourteen (14) modules across.

Initial Supply of Catalyst

EMx™	Three 4-inch depth rows .Identical dimensions for all modules
ESx®	One 5-inch depth row

2 DESIGN BASIS

2.1 Engine Data

The EMx™ system design is based upon the flowing process specifications and operating conditions.

Parameter	Design Value (650F)
Engine Manufacturer & Model	GE LM-6000
Exhaust Gas Flow Rate of Engine	1,085,651 lb/hr
	14,366,680 scfh
Exhaust Gas Flow Rate with Dilution Air added	1,416,846 lb/hr
	18,719,063 scfh
Fuel Type	Natural Gas
Catalyst Temperature	
Minimum	600°F
Operating	650°F
Maximum	700°F
Engine Emissions at Catalyst Inlet	
NOx	25 ppmvd at 15% O_2
CO	30 ppmvd at 15% O_2
HC	3 ppmvd at 15% O_2
PM	3 lbs/hr
SO_2	.3 ppmvd at 15% O_2

2.2 Emissions Performance

EMx is a "NOx trap" technology, where NOx is stored on the surface of the catalyst, then converted to nitrogen and released during the regeneration cycle. The catalyst has a specific capacity to store NOx. As the catalyst captures NOx during the sorption cycle the capacity becomes consumed, the outlet NOx value begins to rise, and the system enters the regeneration cycle to restore the capacity and return the outlet NOx to very low values.

The cyclic nature of this process produces NOx outlet values that rise and fall in a "saw tooth" pattern. The catalyst will be designed so that the top of the "saw tooth" pattern is below emission values defined below, so that the average emission reduction will be greater than the value defined below.

Oxidation of CO and VOCs will be constant and will not exhibit the "saw tooth" pattern characteristic of NOx.

As currently configured, the ESx catalyst will function as a sulfur guard for the EMx NOx trap catalyst. During regeneration the sulfur stored by the ESx catalyst will be released as SO_2 and diverted to the exhaust duct downstream of the EMx reactor. Used in this manner the ESx technology will not permanently remove SOx from the exhaust and the SOx emissions will be identical to that of the engine. As an option, this concentrated, low-volume spent regen gas stream could be directed to the sulfur scrubber system.

The following performance guarantees apply to the proposed system (see Attachment B for warranty information):

Parameter	EMx System Emission Concentration at 15% O_2	Percent Removal
NOx at Catalyst Outlet	2.32 ppmvd	91% guaranteed
CO at Catalyst Outlet	6 ppmvd	80% guaranteed
PM (10/2.5)	2.1 lbs/hr	30 % guaranteed
NMNEHC VOCs at Catalyst Outlet Measured as Aldehydes	< 1ppmvd	90% expected

The catalyst warranty period is 5 years. Expected life of the catalyst is 10-15 years.

2.3 Back Pressure

The catalyst substrate introduces a pressure drop to the flowing engine exhaust. The resulting system backpressure is a function of the size of the gas path (cross-sectional area), exhaust flow rate, catalyst depth, and temperature. The expected level of backpressure across the EMx and ESx catalyst bed at the design conditions is 4.4 inches WC. This value could be reduced by increasing the size of the gas path or changing a number of other variables.

2.4 Emission Reduction Impact

The EMx system is an ultra clean system that greatly reduces emissions over that of conventional combined Carbon Monoxide/Selective Catalytic Reduction catalyst control. The table below highlights the emissions differences in your specific application. These greater reductions can provide for reduced offset fees when permitting your project.

PB Power- City of Anaheim Project
Comparison of Annual Emissions of EMx vs. SCR Alternative

	Estimated Emissions, Pounds Per Year			
	PB Power Original Proposal Four GE LM6000 Turbines with SCR - 1,000 hrs per year	Estimated Emissions from Four GE LM6000s with EMx		
		Expected	Avoided	% Reduction
NOx	20,800	8,320	12,480	60%
CO	32,800	3,280	29,520	90%
NH3	16,560	0	16,560	100%
PM10	12,000	8,400	3,600	30%

3 SCOPE OF SUPPLY

The EmeraChem Scope of Supply for execution of the Project includes the catalyst, equipment and services below and shown in the "Project Division of Responsibility" table. In general, the Scope of Supply can be defined by the following categories:

a. Process design, system detail engineering and project management. Design and drawings are based upon EmeraChem's standards and specifications.

b. EMx™, ESx® catalyst upon EmeraChem standards and specifications.

c. Equipment and components described in Section 2. Designs, specifications, materials of construction, and components supplier selections based upon EmeraChem standards. These systems include the following:

- EMx reactor assembly
- EMx and ESx catalyst
- Air tempering fans and dilution system
- Hydrogen generator and storage tank
- Reactor Transitions and Expansion Joints
- Regeneration Gas Distribution System
- Package boiler producing saturated steam for regeneration gas
- Boiler feedwater and steam system
- Ladders and Platforms
- Exhaust Stack
- Control system
- CFD modeling

d. Technical Advice during installation, commissioning, and startup as described below

3.1 Project Division of Responsibility

SCOPE ITEM	EmeraChem Power	PB Power Anaheim
Engineering Scope of Supply		
EMx Reactor housing & isolation valves.	QEI	
Hydrogen Generator system	H2 Gen	
Electrical panel for H2 Gen and Reactor	QEI	
Interconnecting piping-H2 Gen to Reactor		✓
Process Engineering	Lambert	
Reactor transitions and ducting	Lambert	
Reactor expansion joints	Wahlco	
Gas supply line to H2 Gen		✓
Steam and condensate supply piping		✓
Stack and Silencer	ECP	
Dilution Air System	ECP	
CFD Modeling	ECP	
Hardware Scope of Supply		
EMx™ catalyst	EC	
ESx™ catalyst	EC	
H2 Generator	H2 Gen	
Regeneration gas system	Wahlco	
EMx reactor housing & isolation valves	Wahlco	
Interconnecting piping-H2 Gen to Rx		✓
Electrical panel for H2 Gen and Reactor		✓
Transition to and from Reactor	ECP	
Reactor inlet & outlet expansion joints	ECP	
Stack and Silencer	ECP	
Dilution Air fans and system	ECP	
Saturated boiler system	ECP	
Hydrogen Tank	H2 Gen	
Gas supply line to H2 Gen		✓
Steam and condensate supply piping		✓
Insulation of reactor and piping		✓
UPS		✓
Spent regen gas piping – header to HRSG		✓
Ladders and platforms	Lambert	
Catalyst loading platform	optional	
Installation		
Receiving and verification of goods	ECP	✓
Construction technical supervision	As outlined	✓
Construction craft labor		✓
Construction equipment		✓
Interconnecting wiring and conduit		✓
Catalyst loading	optional	✓
Technical assistance	As outlined	✓
Commissioning & Start-up		
Electrical continuity checks		✓
I/O checks		✓
Pressure/leak tests		✓
Instrument calibration		✓

3.2 Technical Support

A Technical Service Representative for installation and start-up is included in the price. The Technical Service Representative will be supplied as follows:

a. on-site technical advice during installation: three (3) 1-week trips,
b. On-site technical field advice commissioning & startup including classroom instruction on operation and system hands-on training: 30 man days as needed throughout commissioning & startup.
c. Hydrogen generator system integrator will provide onsite personnel for the installation, startup and training of operators up to 10 days without further charge.

Additional support is available based on standard EmeraChem service rates and per diem.

3.3 Exclusions

3.3.1. *The Following Items Are Specifically Excluded From EmeraChem's Scope of Supply:*

a. All required permits
b. Foundations, site construction
c. Mechanical system installation
d. Equipment insulation and heat tracing
e. EMx™ or ESx® catalyst installation, washing and recoating

See also the Project Division of Responsibility Table.

4 PROJECT SCHEDULE

From the receipt of a purchase order, the estimated completion time of this project is approximately 58 weeks, broken down as follows:

6 weeks after receipt of P.O.	Initial process design submittal Initial reactor design submittal
20 weeks after receipt of P.O.	Engineering Design Complete
34 weeks after approval of drawings	Fabrication and delivery of equipment Manufacture and delivery of catalyst

Accelerated deliveries are possible depending on availability of materials and production schedule at the time a purchase order is received by EmeraChem.

5 PRICE AND PAYMENT SCHEDULE

5.1 Price

As described in Sections 2, 3 and 4 of this proposal, the pricing for this EMx™ Multi-Pollutant Emission Reduction "System" includes system hardware, equipment, and components, EMx™, ESx® catalyst, regeneration gas production system, project management, engineering, and technical services.

EMx™ System Price Components	4-LM 6000
System hardware, equipment, and components (including project management, engineering, and technical services)	$ 20,589,901
EMx™, ESx® and steam reformer catalyst without precious metals	$ 6,935,324
Platinum for catalyst (current market price of $1970/troy ounce of Platinum)	$ 15,087,908
Total Capital Price	$ 42,613,133
Reclaim value of precious metals based on current market	($ 12,824,722)
Net Capital Price	$ 29,788,411

As described earlier, the EMx™ technology utilizes precious metal, platinum catalysts. These precious metals give the catalyst true asset value on the plant site. The cost of platinum is passed through to the customer without markup. At the end of its service life the catalyst can be reprocessed to reclaim these precious metals and recover their cash value, or the precious metals can be reclaimed and reused in the manufacture of replacement catalyst. The estimated value of the recovered platinum at today's market price is listed in the above chart.

As an option, a catalyst loading system can be added to provide for quick, easy and safe removal of the catalyst modules for cleaning or replacement.

Catalyst Loading and Handling System (Optional)

System hardware, equipment, and components (including project management, engineering, and technical services)	$785,000 per unit

The prices listed above do not include applicable taxes, installation, and is FCA factory. EmeraChem standard terms and conditions apply. The prices in this proposal are valid for a period of 30 days from the date of this proposal. After 30 days, prices are subject to change without notice. These prices are based on the current industrial value of Platinum (Pt) as of the date of this proposal. If the price of platinum changes by the time of purchase, the catalyst price will be adjusted to compensate for the change in platinum price. The platinum price is the "Industrial Price" as stated in the Wall Street Journal on the day the purchase order is provided.

5.2 Payment Schedule

The following Payment Schedule for the Capital Price is required in order for EmeraChem to purchase and process the material necessary to supply the EMx™ catalyst and associated systems in a time frame consistent with the proposed Project Schedule.

10%	Upon execution of a Purchase Order
40%	Upon sourcing of PGM
45%	Progress Payments through fabrication
5%	Within thirty (30) days of completion of acceptance tests, or within ninety days of completion of installation, whichever occurs first.

5.3 Catalyst Maintenance Services

EmeraChem offers a comprehensive program to handle all catalyst service issues on the EMx™ system along with the provision for technical and operator training. An important benefit of this program is that the catalyst will be maintained to a condition, which optimizes its performance, reliability, and on-line availability thus maximizing the catalyst life. A service proposal can be provided, if desired.

APPENDIX A – Description of Catalytic Principles

Catalyst Oxidation/Absorption Cycle

EMx

The *EMx* catalyst works by simultaneously oxidizing CO to CO_2, VOCs to CO_2 and H_2O, NO to NO_2, and then absorbing NO_2 onto its surface through the use of an alkaline metal solution adsorber coating such as potassium carbonate. These reactions are shown below, and are referred to as the "Oxidation/Absorption Cycle".

$CO + ½O2 \rightarrow CO_2$
$C\ H_2O + O_2 \rightarrow CO_2 + H_2O$
$NO + ½O2 \rightarrow NO_2$
$2NO_2 + K2CO3 \rightarrow CO_2 + KNO2 + KNO3$

ESx

The ESx Sulfur Removal Catalyst works in conjunction with the *EMx* system and is placed upstream of the *EMx* catalyst. The ESx catalyst enhances the efficiency of NOx absorption by removing sulfur compounds from the flue gas. Sulfur is present in the flue gas exhaust primarily as SO_2, which forms potassium sulfate on the *EMx* catalyst. The ESx catalyst acts like a filter and removes the sulfur in the flue gas stream before it reaches the *EMx* catalyst. Chemical reactions for the ESx system oxidation/absorption cycle are shown below.

$CO + ½O2 \rightarrow CO_2$
$SO_2 + ½O2 \rightarrow SO_3$

$SO_3 + SORBER \rightarrow [SO_3 + SORBER]$

Catalyst Regeneration Cycle

EMx

The regeneration of the *EMx* catalyst, one of the features that make the system so unique, is accomplished by passing a dilute reducing gas across the surface of the catalyst in the absence of oxygen. The reductant in the regeneration gas reacts with nitrites and nitrates to form water, elemental nitrogen, and potassium hydroxide. Carbon dioxide in the engine exhaust reacts with potassium hydroxide to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. This cycle is referred to as the "Regeneration Cycle", and the relevant reaction is shown below.

$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H2O + N2$

Water (as steam) and elemental nitrogen are exhausted up the stack instead of NOx, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to begin again. There is not a net gain or net loss of potassium carbonate after the oxidation/absorption and regeneration cycle.

ESx

The reaction for the regeneration cycle is also similar to that of the *EMx* catalyst. The regeneration gas used for the *EMx* and ESx catalyst is the same, allowing them to be regenerated simultaneously.

$$[4SO_3 + SORBER] + 4H2 + CO_2 \rightarrow 4SO_2 + CO_2 + 2H_2O + SORBER$$

The regeneration reaction illustrates that the sorbed SO_2 is not destroyed, but released; hence, the result of the regeneration step is a concentrated stream of SO_2 that can be disposed of or returned to the exhaust downstream of the *EMx* catalyst.

The sulfur dioxide in the above reaction may be removed by passing the spent regeneration gas through a dry scrubber before it is piped into the HRSG to be exhausted to the atmosphere. Capture of sulfur compounds from an exhaust stream using the ESx process has been proven in the laboratory to be on the order of 90% or higher.

Steam Reforming Chemistry

The methane and steam are combined and react over the steam reforming catalyst surface as indicated in the equation below, forming two to four percent hydrogen in the steam carrier gas.

$$CH_4 + 2H2O \rightarrow 4H_2 + CO2$$

APPENDIX B – Required Utilities

The following are the utility consumption rates for four (4) LM-6000 units firing at 100% load.

Utility	Quantity	Pressure	Other
Natural Gas (to produce H_2 gas used in the regen process)	6,681 scfh	15 or 60 psig	pipeline quality
Steam (used to combine with H_2 to be used as regen gas)	35,000 lb/hr	15 psig	Saturated steam
Electricity (regen gas blower and H_2 generator)	37.5 kWh		480 volt, 3-phase
Compressed Air (for actuators on reactor isolation dampers, regen gas block valves and H_2 generator)	315 scfh.	80 psig (100 psig max.)	
DI Water (for use to create H_2)	3.75 gpm		10 mega ohm/cm resistivity
Cooling Water (used to cool off the H_2 generator equipment)	75 gpm		
Boiler Makeup Water (used to create regen gas steam)	7 gpm		RO quality

ATTACHMENTS

Information specific to this EMx™ installation is provided under the following subheadings.

A. Piping and Instrumentation Drawings

Preliminary P&IDs are attached.

B. EMx™ System Performance Warranty

EmeraChem warrants the products provided in accordance with Section III, "Warranty", of EmeraChem Selling Policy 8130.

Mechanical parts provided by EmeraChem subcontractors are warranted to be free of defects in workmanship, material, or title for a minimum period of one (1) year on a pass through basis.

C. Terms & Conditions

The detailed Terms and Conditions are provided in EmeraChem Selling Policy 8130

D. Field Service Policy and Rate Schedule

EmeraChem field service engineers will provided in accordance with EmeraChem's Selling Policy 8190, "Technical Field Services" and Price List PL8199.

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 CANYON POWER PLANT PROJECT*	**Docket No. 07-AFC-9** **PROOF OF SERVICE** (REVISED 7/31/2008)

INSTRUCTIONS: All parties shall either (1) send an original signed document plus 12 copies or (2) mail one original signed copy AND e-mail the document to the address for the Docket as shown below, AND (3) all parties shall also send a printed or electronic copy of the document, which includes a proof of service declaration to each of the individuals on the proof of service list shown below:

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Attn: Docket No. 07-AFC-9
1516 Ninth Street, MS-15
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DECLARATION OF SERVICE

I, Ashley Y. Garner, declare that on January 28, 2009, I deposited copies of the attached **APPLICATION FOR THE CANYON POWER PLANT** in the United States mail at Sacramento, CA with first-class postage thereon fully prepaid and addressed to those identified on the Proof of Service list above.

OR

Transmission via electronic mail was consistent with the requirements of California Code of Regulations, title 20, sections 1209, 1209.5, and 1210. All electronic copies were sent to all those identified on the Proof of Service list above.

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

Ashley Y. Garner