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APPENDIX 8.1F

BACT Analysis

8.1F.0 Evaluation of Best Available Control Technology

The SMAQMD does not publish a BACT guideline. Consequently, to assist in the evaluation of BACT for the proposed turbines, the San Joaquin Valley Unified APCD (SJVUAPCD) BACT guideline for large gas turbines (heat input rating greater than 374 MMBtu/hr) was reviewed. The relevant BACT determinations for this analysis are shown in Table 8.1F-1.

TABLE 8.1F-1
SJVUAPCD BACT Guideline For Large Gas Turbines

Pollutant	Achieved in Practice or Contained in SIP	Technologically Feasible
Nitrogen Oxides	2.5 ppmvd, 1 hr avg, excluding startup and shutdown. SCR or equal and natural gas fuel.	2.5 ppmvd, 1 hr avg, excluding startup and shutdown. SCR or equal and natural gas fuel.
Sulfur Dioxide	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more than 0.75 g S/100 dscf.	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more than 0.75 g S/100 dscf 3. LPG
Carbon Monoxide	6.0 ppmv Oxidation catalyst and natural gas fuel	4.0 ppmv Oxidation catalyst and natural gas fuel or LPG
VOC	2.0 ppmv and natural gas fuel	2.0 ppmv and natural gas fuel
PM_{10}	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel	Air inlet cooler/filter, lube oil vent coalescer and natural gas fuel or LPG

Notes: (1) Technologically feasible and cost effective
(2) Achieved in practice

The EPA RACT-BACT-LAER Clearinghouse (RBLC) was also consulted to review recent EPA BACT decisions for gas-fired gas turbines. These recent BACT decisions are summarized in Table 8.1F-2 below. NOx levels shown in these BACT determinations are very high, although EPA has recently stated that a 2.5 ppm limit is achievable in practice. CO levels in this listing are also relatively high, and do not indicate that oxidation catalysts have been considered BACT for CO or VOCs.

The ARB's BACT Clearinghouse Database was also reviewed for recent BACT decisions regarding large gas turbine projects in California. Relevant BACT decisions are summarized in Table 8.1F-3. NOx levels shown in these determinations range from 5 to 2.5 ppm.

Finally, the ARB's Guidance for Power Plant Sitting and Best Available Control Technology was also reviewed. The relevant BACT levels recommended in the ARB power plant guidance document are summarized in Table 8.1F-4.

The Project proposes to use dry low-NOx combustors with selective catalytic reduction technology that will achieve a NOx exhaust concentration of 2.5 ppmv or less (1-hr average), 2.0 ppmv (annual average), and a CO exhaust concentration of 6 ppmv. The gas turbines will be fueled with natural gas to minimize SO_2 and PM_{10} emissions. VOC levels are inherently very low for the turbines (i.e., 2 ppmv) and no further reductions are needed to comply with BACT. These pollutant levels will achieve emission reductions consistent with the BACT definition contained in SMAQMD regulations, and with the published SJVUAPCD and ARB BACT guidelines for gas turbine power plants. The control systems will also achieve an ammonia slip of 10 ppmv (3-hour average). A more detailed top down analysis for BACT for NOx and ammonia emissions is included as Attachment 8.1F-1.

TABLE 8.1F-2
Gas Turbine BACT Determinations For EPA RBLC Clearinghouse

FACILITY/LOCATION	DATE PERMIT ISSUED	EQUIPMENT/RATING	NOX LIMIT/CONTROL TECHNOLOGY	CO LIMIT/CONTROL TECHNOLOGY
Alabama Power Company McIntosh, AL	7/10/97	100 MW combustion turbine w/ duct burner	15 ppm (dry low-NOx burners)	n/a
Lordsburg L.P. Lordsburg, NM	6/18/97	100 MW combustion turbine	15 ppm (dry low-NOx technology)	50 ppm (dry low-NOx technology)
Mead Coated Board, Inc. Phenix City, AL	3/12/97	25 MW combustion turbine w/ fired HRSG	25 ppm (dry low-NOx combustor)	28 ppm (proper design and good combustion practices)
Northern California Power Agency Lodi, CA	10/02/97	GE Frame 5 gas turbine	25 ppm	n/a
Portside Energy Corp. Portage, IN	5/13/96	63 MW gas turbine w/ unfired HRSG	n/a	10 ppm (good combustion)
Southwestern Public Service Hobbs, NM	2/15/97	Gas turbine	15 ppm w/o power augmentation 25 ppm w/ augmentation	good combustion practices

TABLE 8.1F-3
Summary Of BACT Determinations From ARB BACT Clearinghouse

FACILITY/DISTRICT	PERMIT NO.	EQUIPMENT/RATING	NOX LIMIT/CONTROL TECHNOLOGY	VOC/HC LIMIT/CONTROL TECHNOLOGY
Sacramento Cogeneration Authority Sacramento Metropolitan AQMD	A330-849-98 A330-850-98 A330-851-98	GE LM6000 combined-cycle gas turbine w/ supplemental firing (42 MW each)	5 ppm (water injection and SCR)	oxidation catalyst (10% destruction efficiency)
Sacramento Power Authority Sacramento Metropolitan AQMD	A330-852-98	Siemens V84.2 combined-cycle gas turbine w/ supplemental firing (103 MW)	3 ppm (dry low- NOx and SCR)[1]	oxidation catalyst (5% destruction efficiency)
Central Valley Financing Authority Sacramento Metropolitan AQMD	A330-854-98	GE LM6000 combined-cycle gas turbine w/ supplemental firing (42 MW)	5 ppm (water injection and SCR)	oxidation catalyst (10% destruction efficiency)
SEPCO	A330-855-98	GE Frame 7EA gas turbine w/ supplemental firing (82 MW)	5 ppm (dry low-NOx combustion and SCR)[2]	oxidation catalyst (5% destruction efficiency)
La Paloma Generating Company, LLC	S-3412-1	ABB Model GT-24 gas turbine w/o supplemental firing (262 MW each)	2.5 ppm (dry low-NOx combustion and SCR)	
Sutter Power Plant	A330-882-99	Westinghouse 501F gas turbine w/ supplemental firing (250MW each)	2.5 ppm (dry low-NOx combustion and SCR)	
Crockett Cogeneration	A330-859-98	GE Frame 7FA gas turbine w/ supplemental firing (240MW)	5 ppm (dry low-NOx combustion and SCR)	

Note: 1. District indicates that applicant proposed 2.6 ppm to lower offset liability.
2. Project was never constructed.

TABLE 8.1F-4
ARB BACT Guidance For Power Plants

POLLUTANT	BACT
Nitrogen Oxides	2.5 ppmv @ 15% O2 (1-hour average) 2.0 ppmv @ 15% O2 (3-hour average)
Sulfur Dioxide	Fuel sulfur limit of 1.0 grains/100 scf
Carbon Monoxide	Nonattainment areas: 6 ppmv @ 15% O2 (3-hour average) Attainment areas: District discretion
VOC	2 ppmv @ 15% O2 (3-hour average)
NH_3	5 ppmv @ 15% O2 (3-hour average)
PM10	Fuel sulfur limit of 1.0 grains/100 scf

Attachment 8.1F-1
Top Down Analysis for BACT for NOx and Ammonia Emissions

BACT is defined in SMAQMD Rule 202, Section 207, as:

"207.1 For any emissions unit the most stringent of:

a. The most effective emission control device, emission limit, or technique, singly or in combination, which has been required or used for the type of equipment comprising such an emissions unit unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such limitations required on other sources have not been demonstrated to be achievable in practice.

b. Any alternative basic equipment, fuel, process, emission control device or technique, singly or in combination, determined to be technologically feasible and cost-effective by the Air Pollution Control Officer.

207.2 In making a BACT determination for each affected pollutant, the Air Pollution Control Officer may consider the overall effect of the determination on other affected pollutants. In some cases the lowest emission rates may be required for one or more affected pollutants at the cost of not achieving the lowest emission rate for other pollutants. The Air Pollution Control Officer shall discuss these considerations in the Preliminary Decision prepared pursuant to Section 405.

207.3 Under no circumstances shall BACT be determined to be less stringent than the emission control required by an applicable provision of district, state or federal laws or regulations, or contained in the implementation plan of any State for such class or category of stationary source unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such limitations are not achievable.

Of these "prongs" of the BACT definition, the first and second (achieved in practice and technologically feasible) 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
5. Select BACT

This procedure is followed for each of the two pollutants evaluated in this analysis. While BACT is not required for ammonia emissions, this analysis includes an evaluation of ammonia as a corollary environmental impact in the assessment of BACT for NOx.

1. Control of Nitrogen Oxides

a. Identify All Control Technologies

The maximum NOx emission rate for this analysis is considered to be 75 ppmvd @ 15% O_2, based on the governing new source performance standard (40 CFR 60 Subpart GG). This maximum emissions rate provides the frame of reference for the evaluation of control effectiveness and feasibility. The maximum degree of control, resulting in the minimum emission rate, is a combination of dry low-NOx combustors and either selective catalytic reduction or SCONOx to achieve a long term NOx limit of approximately 1 ppmvd. Intermediate levels of control are also evaluated.

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 gas turbines include the following:

Wet combustion controls

$ Water injection

$ Steam injection

Dry combustion controls

$ Dry low-NOx combustor design

$ Catalytic combustors (e.g., XONON)

$ Other combustion modifications

Post-combustion controls

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

b. Eliminate Technically Infeasible Options

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

Combustion Modifications

(i) 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. The water or steam-to-fuel injection ratio is the most significant factor affecting the performance of wet controls. Steam injection techniques can reduce NOx emissions in gas-fired gas turbines to between 15 and 25 ppmv at 15% O_2; the practical limit of water injection has been demonstrated at approximately 25-42 ppmv @ 15% O_2 before combustor damage becomes significant. Higher diluent:fuel ratios (especially with steam) result in greater NOx reductions, but also increase emissions of CO and hydrocarbons, reduce turbine efficiency, and may increase turbine maintenance requirements. The principal NOx control mechanisms are identical for water and steam injection. Water or steam is injected into the primary combustion chamber to act as a heat sink, lowering the peak flame temperature of combustion and thus lowering the quantity of thermal NOx formed. The injected water or steam exits the turbine as part of the exhaust.

Since steam has a higher temperature/enthalpy than water, more steam is required to achieve the same quenching effect. Typical steam injection ratios are 0.5 to 2.0 pounds steam per pound fuel; water injection ratios are generally below 1.0 pound water per pound fuel. Because water has a higher heat absorbing capacity than steam (due to the temperature and to the latent heat of vaporization associated with water), it takes more steam than water to achieve an equivalent level of NOx control.

Although the lower peak flame temperature has a beneficial effect on NOx emissions, it can also reduce combustion efficiency and prevent complete combustion. As a result, CO and VOC emissions increase as water/steam-to-fuel ratios increase. Thus, the higher steam-to-fuel ratio required for NOx control will tend to cause higher CO and VOC emissions from steam-injected turbines than from water-injected turbines, due to the kinetic effect of the water molecules interfering with the combustion process. However, steam injection can reduce the heat rate of the turbine, so that equivalent power output can be achieved with reduced fuel consumption and reduced SO_2 emission rates.

Water and steam injection have been in use on both oil- and gas-fired turbines in all size ranges for many years so these NOx control technologies are clearly technologically feasible and widely available.

(ii) 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. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor primary combustion zone to cool the flame, thereby reducing the rate of thermal NOx formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NOx formation.

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. This technology is effective in achieving NOx emission levels comparable to levels achieved using wet injection without the need for large volumes of purified water and without the increases in CO and VOC emissions that result from wet injection. Several turbine vendors have developed this technology for their engines, including the engine proposed for this project. This control technique is technically feasible.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5 MW natural gas-fired turbine in California and commercial availability of the technology for a 200 MW GE Frame 7G natural gas-fired turbine had previously been announced for one project. The combustor used in the demonstration engine is generally comparable in size to that used in GE Frame 7F engines; however, the technology has not been announced commercially for the Frame 7F engines proposed for this project, and the use of XONON technology is no longer proposed for the previously-announced 7G application. General Electric has indicated the technology is not yet commercially available. XONON is reported to be commercially available for 10 MW turbines manufactured by GE. No turbine vendor, other than General Electric, has indicated the commercial availability of catalytic combustion systems at the present time; therefore, catalytic combustion controls are not available for this specific application and are not discussed further.

(iii) 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. NOx conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NOx combustion controls. SCR requires the consumption of a reagent (ammonia or urea), and requires periodic catalyst replacement. Estimated levels of NOx control are in excess of 90%.

Selective non-catalytic reduction (SNCR) involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1200° to 2000° F and is most commonly used in boilers. The exhaust temperature for the proposed gas turbine ranges from 1087° to 1200° F, well below the minimum SNCR operating temperature. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for this application. Even when technically feasible, SNCR is unlikely to achieve NOx reductions in excess of 80%-85%.

Nonselective catalytic reduction (NSCR) uses a catalyst without injected reagents to reduce NOx emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16 percent. For this reason, NSCR is not technologically feasible for this application.

SCONOx 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, CO, and VOCs and adsorbs NO_2 onto the catalyst surface where they are stored as nitrates and nitrites. The catalyst is a monolith design, made from a ceramic substrate, with a platinum-based catalyst and a potassium carbonate coating. The SCONOx catalyst has a limited adsorption capability, and requires regeneration on a cycle of approximately 12-15 minutes.[1] Regeneration occurs by dividing the SCONOx catalyst system in a series of sealable compartments. At any point in time, approximately 20% of the compartments in a SCONOx system would be in regeneration mode, and the remaining 80% of the compartments would be in oxidation/absorption mode.[2]

Regeneration of the SCONOx catalyst must occur in an oxygen-free environment. Consequently, each SCONOx compartment is equipped with front and rear seals to isolate the compartment from the exhaust gas stream during regeneration operation.

Regeneration is accomplished by passing a gas mixture (regeneration gases) containing methane, carbon dioxide and hydrogen over the catalyst beds.[3] Regeneration gases are created using a separate, external reformer. Initial attempts to create regeneration gases from natural gas and steam

[1] Personal communication, ABB Environmental, 1/18/00.
[2] Stone & Webster, "Independent Technical Review – SCONOx Technology and Design Review", February 2000.
[3] Stone & Webster, op cit

within the SCONOx catalyst bed (internal autothermal regeneration) failed to produce consistent results; this technology is not being proposed by ABB Environmental at the present time.[4]

The SCONOx catalyst bed, as designed for F-class gas turbines, includes a SCOSOx catalyst (or guard bed) followed by two or more SCONOx catalysts in series. The SCOSOx catalyst is intended to remove trace quantities of sulfur-bearing compounds from the exhaust gas stream, so as to avoid poisoning of the SCONOx catalyst. Like the SCONOx catalyst, the SCOSOx catalyst is regenerated. The regeneration for the two catalyst types occurs at the same time, with the same regeneration gas supply provided to both. Regeneration gases for the SCOSOx catalyst exit the module separately from the SCONOx regeneration gases; however, both regeneration gases are returned to the gas turbine exhaust stream downstream of the SCONOx module.[5]

The external reformer used to create the regeneration gases is supplied with steam and natural gas. For one F-class turbine, an estimated 15,000 to 20,000 lbs/hr of 600°F steam is required, along with approximately 100 pounds per hour (2.2 MMbtu/hr) of natural gas.[6] To avoid poisoning the reformer catalyst, the natural gas supplied to the reformer passes through an activated carbon filter to remove sulfur-bearing compounds.[7]

To properly treat the exhaust gas without undue backpressure, an estimated 40-60 catalyst modules would be required for an F-class machine.[8] (These modules are assembled, four to a shelf, to create 10-15 shelves.) The pressure drop associated with a NOx removal efficiency of 90% is approximately 5" of water.[9] The estimated space velocity for such a system is 22,000/hour.[10]

The regeneration cycle time is expected to be controlled using a feedback system based on NOx emission rates.[11] That is, the higher the NOx emissions are relative to the design level, the shorter the absorption cycle, and regeneration cycles will occur more frequently. This is analogous to the use of feedback systems for controlling reagent (ammonia or urea) flow rates in an SCR system.

Maintenance requirements for SCONOx systems are expected to include periodic replacement of the reformer fuel sulfur carbon unit, periodic replacement of the reformer catalyst, periodic washings of the SCOSOx and SCONOx catalyst beds, and periodic replacement of the SCOSOx and SCONOx catalyst beds. The replacement frequency for the reformer sulfur carbon unit and reformer catalyst are unknown to SMUD at present. The SCOSOx catalyst is expected to require washing once per year. The lead SCONOx catalyst bed is expected to require washing once per year, while the trailing SCONOx catalyst bed(s) are expected to require washing once every three years. The annual catalyst washing process is expected to take approximately three days for an F-class machine, with an estimated annual cost of $200,000.[12] The estimated catalyst life is reported to be 7 washings[13]; the guaranteed catalyst life is 3 years[14]

The absorption operating range for the SCONOx system is 300°F to 700°F, with an optimal temperature of approximately 600°F.[15] However, regeneration cycles are not initiated unless the

[4] ABB Environmental, op cit
[5] ABB Environmental, op cit
[6] Ibid
[7] Stone & Webster, op cit
[8] ABB Environmental, op cit
[9] Ibid
[10] Ibid
[11] Ibid
[12] Ibid
[13] Ibid
[14] Letter from ABB Alstom Power to Bibb & Associates dated May 5, 2000. (ABB Three Mountain Power or ABB TMP)
[15] Ibid

catalyst bed temperature is above 450°F to avoid the creation of hydrogen sulfide during the regeneration of the SCOSOx catalyst.[16]

Estimates of control system efficiency vary. ABB Environmental has indicated that the SCONOx system is capable of achieving a 90% reduction in NOx, a 90% reduction in CO to a level of 2 ppm, and an 80%-85% reduction in VOC emissions.[17] (This VOC reduction is not likely to be achieved with low VOC inlet concentrations, in the 1 – 2 ppm range.[18]) Commercially quoted NOx emission rates for the SCONOx system range from 2.0 ppm on a 3-hour average basis, representing a 78% reduction[19], to 1.0 ppm with no averaging period specified (96% reduction)[20]. The SCONOx system does not control or reduce emissions of sulfur oxides or particulate matter from the combustion device.[21]

The SCONOx system has been applied at the Sunlaw Federal Cogeneration Plant in Vernon, California since December 1996, at the Genetics Institute Facility in Massachusetts, and at a facility at San Diego State University (SDSU). The Sunlaw facility uses an LM-2500 gas turbine, rated at a nominal 23 MWe, the Genetics Institute facility has a 5 MWe Solar gas turbine, and the SDSU facility uses a small Solar gas turbine. The SCONOx system was proposed for use by PG&E Generating Company at its La Paloma and Otay Mesa facilities; however, PG&E Generating is constructing the La Paloma facility using SCR systems[22], and the current owner of the Otay Mesa project no longer plans to use the SCONOx system at that site. In addition, the technology's co-developer, Sunlaw, had proposed to use the technology in conjunction with ABB gas turbines at the Nueva Azalea site in Southern California; however, that project has been suspended by the project developer. Finally, SCONOx is proposed for use at a 43 MW gas turbine under construction in Redding, California.

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
- SCONOx

c. Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies are ranked by NOx control effectiveness in Table 8.1F-5.

[16] ABB Environmental, op cit. Stone & Webster, op cit
[17] ABB Environmental, op cit
[18] Ibid
[19] ABB TMP, op cit
[20] Letter from ABB Alstom Power to Sunlaw Energy Corporation dated February 11, 2000. (ABB Sunlaw)
[21] ABB Environmental, op cit
[22] Ibid

TABLE 8.1F-5
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
SCONOx	Yes[1]	Yes[2]	>90% reduction 1 – 2.5 ppm	Reduced CO; potential reduction in VOC	Decreased efficiency

Notes:

1. There are no standard, commercial guarantees for utility-scale projects for this technology available in the public domain.
2. Technology has been used on small (5 MW and 22 MW) gas turbines for a limited period of time, and with limited success. Has not been used on utility-scale gas turbines.

d. Evaluate Most Effective Controls and Document Results

Water and steam injection are control technologies that, for large gas turbines, have been largely superseded by dry low-NOx combustors, due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of this technology. Since the project proposes to use dry low NOx combustors, no further discussion of water injection, steam injection, or dry low NOx combustors is necessary.

The potential performance of SCR and SCONOx, 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). 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 SMAQMD has not established formal criteria in its BACT policy for determining when emission control technologies should be considered achieved in practice (AIP) for the purposes of BACT determinations. The SJVUAPCD criteria include the following elements:

<u>Comparable Equipment:</u> The rating and capacity of the unit where the control has been achieved must be approximately the same as that of the proposed unit.

<u>Class of Source:</u> The type of business (that is, class of source) where the emissions units are

utilized must be the same.

Availability of Resources: The availability of resources (water, fuel, etc.) necessary for the control technology must be approximately the same.

Other factors considered in this evaluation, based in part on the achieved in practice criteria adopted by the South Coast AQMD (SCAQMD) are as follows:

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

Reliability: All control technologies should 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 should have at least 183 cumulative days of operation. During this period, the basic equipment should 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 should 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 should be identified. The verification should be based on a performance test or tests, when possible, or other performance data.

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

Discussion of SCR-Based Limits – Achieved in Practice Criteria

SCR has been achieved in practice at numerous gas turbine installations throughout the world. Although there are a large number of gas turbines equipped with SCR systems, there are relatively fewer systems in operation that are designed to meet low NOx permit limits of 2.5 ppm or less.

Available CEMS data from the Sacramento Power Authority (SPA) plant in Sacramento, California, indicate NOx control levels on a continuous basis that are in compliance with a 3.0 ppm limit. Actual NOx levels from that facility, which is equipped with a 120 MW (nominal) Siemens V84.2 turbine, are comfortably below that limit, at approximately 2.5 ppm. This facility has experienced a limited number of events above the permit limit; in each case, the excursion has been associated with a trip of the gas turbine from pre-mix, or low-NOx, mode into diffusion mode. The permit for the facility has since been modified to accommodate up to ten hours per year of excursions above the 3 ppm permit limit under specified conditions.

The extrapolation of SCR experience gained at higher NOx concentrations (3-5 ppm), where there are more sites in operation, to lower NOx permit limits depends on controlling turbine exhaust (SCR inlet) NOx concentrations, increasing catalyst size, improving feed-forward and feed-back control system design to ensure better process control, and ensuring good distribution of reagent to match the distribution of NOx levels. The experience at the SPA site, however, indicates that the ability of the SCR system to track NOx emissions changes upstream of the catalyst is further challenged at progressively lower concentrations.

A further exacerbating factor is related to measurement uncertainty. The South Coast AQMD has indicated that current NOx measurement methods for stationary sources are accurate to ±1 ppm,[23] which becomes problematic at NOx permit levels of 5 ppm and lower.

The following paragraphs evaluate the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.5 ppm and lower) using SCR technology.

Comparable Equipment: SCR has been widely used on units of similar rating and capacity as that of the proposed units.

Class of Source: SCR has been widely used on utility-scale gas turbines, the same class of source as what is proposed for this project.

Availability of Resources: The necessary resources and other materials that are needed for the effective operation of SCR technology are available at the Project site.

Additional achieved in practice considerations are as follows:

Commercial availability: SCR technology is available with standard commercial guarantees for NOx levels at least as low as 1 ppm. Consequently, this criterion is satisfied.

Reliability: SCR technology has been shown to be capable of achieving NOx levels consistent with a 3 ppm permit limit during extended, routine operations of the SPA facility. 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 below 3 ppm. At the SPA site, short-term excursions have resulted in NOx concentrations above 3 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. Consequently, the application of SCR technology to achieve extremely low NOx levels should reflect the potential for infrequent NOx excursions, under specified conditions. Permits have been issued for at least two utility-scale projects that limit NOx emissions to not more than 2.0 ppm on a 1-hour average basis. However, neither of these facilities has commenced operation, and no assessment can be made of their ability to meet a 2.0 ppm, 1-hour average limit on a consistent basis.

Conclusion: SCR technology capable of achieving NOx levels below 3 ppm is considered to be achieved in practice. The proposed permit limits for the Project includes a NOx limit of 2.5 ppm on a 1-hour average basis. This proposed limit is consistent with the available data. The achievement of NOx concentrations below this level, on either a short term or long term basis, is not demonstrated in practice.

Discussion of SCONOx-Based Limits – Achieved in Practice Criteria

SCONOx has been demonstrated in service in three applications: the Federal Cogeneration Facility in Vernon, California, the Genetics Institute Facility in Massachusetts, and the SDSU facility in San Diego, CA. Because these turbines are much smaller than those proposed for the Project, issues related to the application of SCONOx technology to the Project need to be evaluated, in addition to a review of other criteria.

Comparable Equipment: The ratings and capacities of the units where SCONOx has been achieved are much smaller than those of the proposed units. Therefore, this criterion is not met.

[23] See, e.g., South Coast AQMD Protocol for Rule 2012.

Class of Source: None of the existing demonstration turbines is a utility-scale gas turbine. As the type of business (that is, class of source) where the emissions units are utilized are not the same, this criterion is not met.

Availability of Resources: SCONOx requires more water for washing of the reactor beds, and thus results in more wastewater for disposal. Although the water and fuel needed for operation of SCONOx technology are available at the Project site, the additional wastewater that would need to be treated and disposed of onsite is an environmental impact that should be considered.

Continuous emissions monitoring (CEMS) data from the Federal Vernon facility have been evaluated in stages, as the data have been made public. The results of these evaluations are presented below.

Available CEMS data from the Federal Vernon facility were obtained from EPA, covering the period July through December 1997. EPA had indicated that this time period reflected the improved performance of the SCONOx system, and led to EPA's March 23, 1998 letter regarding BACT and LAER requirements for combined cycle gas turbines.

A review of the available SCONOx data for the last half of 1997 indicates that, at the Federal site, up to 12 exceedances per year could be expected above a 3.0 ppm, 3-hour average limit, even when exceedances related to startups and shutdowns were excluded.[24]

EPA and the California Air Resources Board have recommended BACT/LAER levels for combined cycle gas turbines of either 2.0 ppm on a 3-hour average basis, or 2.5 ppm on a 1-hour average basis. Under the BACT/LAER levels recommended by these agencies, the 1997 SCONOx data from the Federal site indicate that a 3-hour average limit of 2.0 ppm would be exceeded 44 times per year, and a 1-hour average limit of 2.5 ppm would be exceeded 24 times per year. Again, these data exclude exceedances associated with startups and shutdowns, as described above.

The data supporting these conclusions are shown in Table 8.1F-6.

The first part of this table shows, by month and quarter, the number of all 1-hour and 3-hour exceedances of various NOx emissions levels associated with operation of the SCONOx system during the period that resulted in EPA's March 1998 letter. The second part of the table shows exceedances that were not due to turbine startups or shutdowns.

[24] For the purposes of the reviews of SCONOx presented in this report, a startup for the LM-2500 gas turbine at the Federal Vernon facility was defined as a period not to exceed 120 minutes; a shutdown was defined as a period not to exceed 60 minutes. These definitions are conservative in that aeroderivative gas turbines, such as those in use at the Vernon facility, are generally capable of completing a startup, with all emission control systems active, within 30 minutes, and are capable of completing a shutdown within 15 minutes. Permits for many LM-2500 combined cycle facilities expressly limit startups to not more than 30 or 60 minutes.

TABLE 8.1F-6
SCONOx Performance – Summary Prepared by Sierra Research
July 1, 1997 to December 31, 1997

SCONOx Excursions Review										
All excursions:										
	No. of Valid	CEMS	No. of 1-hr periods exceeding			No. of 3-hr periods exceeding			Highest reading	
Month	CEMS Hrs	Avail, %	2.0 ppmc	2.5 ppmc	3.0 ppmc	2.0 ppmc	2.5 ppmc	3.0 ppmc	1-hr avg	3-hr avg
Jul	739.00	99.33	3	3	2	1	0	0	4.2	2.3
Aug	741.00	99.60	4	3	2	5	0	0	4.4	2.2
Sept	715.00	99.31	3	2	2	3	2	2	5.0	3.7
Quarter	**2195.00**	**99.41**	**10**	**8**	**6**	**9**	**2**	**2**	**5.0**	**3.7**
Oct	731.00	98.25	9	5	5	10	9	8	10.9	7.5
Nov	716.00	99.44	18	16	14	29	19	14	9.6	6.3
Dec	723.00	97.18	6	4	2	7	4	1	5.4	3.2
Quarter	**2170.00**	**98.28**	**33**	**25**	**21**	**46**	**32**	**23**	**10.9**	**7.5**
Excursions not due to startups or shutdowns:										
	No. of Valid	CEMS	No. of 1-hr periods exceeding			No. of 3-hr periods exceeding			Highest reading	
Month	CEMS Hrs	Avail, %	2.0 ppmc	2.5 ppmc	3.0 ppmc	2.0 ppmc	2.5 ppmc	3.0 ppmc	1-hr avg	3-hr avg
Jul	739.00	99.33	1	1	0	0	0	0	2.6	1.8
Aug	741.00	99.60	3	2	1	4	0	0	3.5	2.2
Sept	715.00	99.31	1	0	0	0	0	0	2.2	2.0
Quarter	**2195.00**	**99.41**	**5**	**3**	**1**	**4**	**0**	**0**	**3.5**	**2.2**
Oct	731.00	98.25	5	3	3	5	5	5	10.9	7.5
Nov	716.00	99.44	5	4	3	8	2	1	8.6	3.8
Dec	723.00	97.18	4	2	1	5	2	0	4.0	2.8
Quarter	**2170.00**	**98.28**	**14**	**9**	**7**	**18**	**9**	**6**	**10.9**	**7.5**
Note:	All NOx readings corrected to 15% oxygen.									

In this analysis, no more than 2 hours of NOx emissions following a startup were treated as part of the startup. For the 3-hour averages, any average that included a startup hour was attributed to the startup. This is in contrast with the approach taken by Goal Line Environmental Technologies (GLET) in its comments accompanying the data reports, in which it is clear that startup periods were considered to extend as much as 6 hours. (This is particularly unsuitable for aeroderivative turbines such as those used at the Federal facility, which are known for their ability to start within tens of minutes.) NOx emissions greater than 2 ppm occurring during these long startup periods were reported by GLET, but were not considered to be exceedances.

In summary, using a 2-hour startup period for aeroderivative gas turbines, the data reported by GLET to EPA for 1997 do not support a BACT determination below 3 ppm. Based solely on the SCONOx data presented to EPA, even a NOx limit at 3.0 ppm would have to provide for excursions, other than startups and shutdowns, above that limit. The number of excursions needed would depend upon the NOx limit selected and the emission control technology employed.

Additional data have been generated at the Federal site, and were provided to EPA Region IX by CURE.[25] These data were for the period April 1, 1999 through December 31, 1999, and were provided to Sierra Research by EPA Region IX.[26] The more recent data are consistent with the

[25] Letter dated March 14, 2000, from Katherine Poole, Adams Broadwell Joseph & Cardozo, to Steve Branoff, EPA Region IX.
[26] Letter dated June 28, 2000 from Duong Nguyen, EPA Region IX, to Nancy Matthews, Sierra Research.

earlier data, and are summarized in Table 8.1F-7.

The 1999 CEMS data from the Federal facility indicated that the turbine equipped with SCONOx was operated fewer than 2,600 hours during the nine-month period for which data were provided. During this period, the turbine was started 149 times. The CEMS data for CO, in particular, are suspect; more than 60% of the CO values reported were less than zero, indicating that the CO analyzer was not properly calibrated on a daily basis. For this reason, the CO data for this period were not analyzed further.

The NOx emissions data for this period were analyzed to evaluate compliance with five hypothetical emission limits (3.0, 2.5, 2.0, 1.5, and 1.3 ppm) and three compliance averaging periods (15 minute, 1 hour, 3 hour). Valid data periods were considered to be those that excluded startups, shutdowns, and initiation of fuel flow to the engine, and lasting until the NOx emission limit under evaluation was met, but not exceeding a period of two hours. Shutdown periods were defined to be periods ending with the cessation of documented CEMS maintenance. Startups were defined to be periods commencing with the fuel flow to the engine and starting when the NOx emission limit under evaluation was no longer met, but not exceeding a period of 30 minutes. A valid 1-hour average period was defined to require at least two valid 15-minute periods; a valid 3-hour average period was defined to require at least two valid 1-hour average periods. All of the above definitions are typical for utility-scale gas turbine CEMS systems.

TABLE 8.1F-7

SCONOx Performance – Summary Prepared by Sierra Research

April 1, 1999 to December 31, 1999

Plant Statistics

Total Hours in Review Period	6,400	
Number of Operating Hours	2,583	
Number of Turbine Starts	149	
Number of CEM Data Periods with Turbine Operating	10,331	
Number of negative CEM values		
NOx:	0	0%
CO:	6,494	63%

Valid Data Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) -> Averaging Period	**3.0**	**2.5**	**2.0**	**1.5**	**1.3**
15 min	9,861	9,813	9,742	9,649	9,607
1 hour	2,501	2,491	2,470	2,445	2,434
3 hour	2,498	2,488	2,468	2,445	2,434

Exceedance Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) -> Averaging Period	**3.0**	**2.5**	**2.0**	**1.5**	**1.3**
15 min	71	77	92	111	124
1 hour	18	21	24	29	32
3 hour	20	22	26	32	36

The data indicated that there were 9,600 to 9,900 valid 15-minute periods, excluding startups, shutdowns, and CEMS maintenance, depending on the NOx limit being evaluated. There were numerous exceedances of the hypothetical NOx limits during these periods, ranging from 71 periods in which NOx emissions exceeded 3.0 ppm to 124 periods in which NOx emissions exceeded 1.3 ppm.

There were approximately 2,500 valid 1-hour average periods in the data set, excluding startups, shutdowns, and CEMS maintenance. For 1-hour average limits, the data again showed numerous exceedances, ranging from 18 exceedances of a 3.0 ppm NOx limit to 32 exceedances of a 1.3 ppm limit. Finally, during the approximately 2,500 valid 3-hour average periods in the data set, there were 20 exceedances of a 3.0 ppm limit and 36 exceedances of a 1.3 ppm NOx limit.

In summary, these more recent data fail to support the conclusion that the SCONOx system at the Federal facility is capable of consistently maintaining low NOx levels of 3.0 ppm or less. Depending on the NOx limit evaluated, the periods of non-compliance over a nine-month period ranged from 18 to 32 hours, excluding periods of turbine startup, shutdown, and CEMS maintenance. While each of the exceedances was accompanied in the data file with an explanation, these explanations do not eliminate the exceedances. In fact, of the 24 exceedances of a 3.0 ppm NOx limit on a 1-hour average basis observed in the 1999 data, 14 were explicitly attributed to problems with the SCONOx system in the file presenting the CEMS data.

More recently, Goal Line Environmental has made available CEMS data from a five-month period in 2000. The 2000 CEMS data from the Federal facility indicated that the turbine equipped with SCONOx was operated for approximately 2,000 hours during this five-month period. During this period, the turbine was started 135 times. The CEMS data for CO remain suspect; approximately 28% of the CO values reported were less than zero, indicating that the CO analyzer was not properly calibrated on a daily basis. For this reason, the CO data for this period were not analyzed further.

As with the 1999 data, the NOx emissions data for this period were analyzed to evaluate compliance with five hypothetical emission limits (3.0, 2.5, 2.0, 1.5, and 1.3 ppm) and three compliance averaging periods (15 minute, 1 hour, 3 hour). The same criteria used for the 1999 data for determining valid data periods, startup periods, and shutdown periods were used for the 2000 CEMS data. The data for 2000 are shown in Table 8.1F-8.

Table 8.1F-8

Sunlaw Cogeneration Partners
SCONOx Performance - Summary Prepared by Sierra Research
April 1, 2000 to August 31, 2000

Plant Statistics

Total Hours in Review Period	3,672	
Number of Operating Hours	2,021	
Number of Turbine Starts	135	
Number of CEM Data Periods with Turbine Operating	18,995	
Number of negative CEM values		
NOx:	0	0%
CO:	5,330	28%

Valid Data Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) ->	**3.0**	**2.5**	**2.0**	**1.5**	**1.3**
Averaging Period					
15 min	7,690	7,615	7,532	7,422	7,371
1 hour	2,003	1,994	1,967	1,931	1,913
3 hour	2,001	1,992	1,963	1,927	1,908

Exceedance Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) ->	**3.0**	**2.5**	**2.0**	**1.5**	**1.3**
Averaging Period					
15 min	45	50	59	74	84
1 hour	15	18	20	22	27
3 hour	16	19	21	25	29
Annualized Basis					
Averaging Period					
15 min	108	120	142	178	202
1 hour	36	43	48	53	65
3 hour	38	46	50	60	70

The data indicated that there were 7,300 to 7,700 valid 15-minute periods, excluding startups, shutdowns, and CEMS maintenance, depending on the NOx limit being evaluated. There were numerous exceedances of the hypothetical NOx limits during these periods, ranging from 108 periods in which NOx emissions exceeded 3.0 ppm to 202 periods in which NOx emissions exceeded

1.3 ppm.

There were approximately 2,000 valid 1-hour average periods in the data set, excluding startups, shutdowns, and CEMS maintenance. For 1-hour average limits, the data again showed numerous exceedances, ranging from 36 exceedances of a 3.0 ppm NOx limit to 65 exceedances of a 1.3 ppm limit. Finally, during the approximately 2,000 valid 3-hour average periods in the data set, there were 38 exceedances of a 3.0 ppm limit and 70 exceedances of a 1.3 ppm NOx limit.

As was the case with the 1999 CEMS data, the 2000 CEMS data fail to demonstrate that the SCONOx system is capable of achieving NOx levels considered to represent BACT on a consistent basis.

Table 8.1F-9 compares the results of the analyses of the 1997, 1999, and 2000 data, with all three data sets normalized to predict exceedances over a 12-month period.

The more recent data do not indicate improved performance as compared with the 1997 CEMS data.

Table 8.1F-9
Comparison of 1997, 1999 and 2000 SCONOx CEMS Data
Exceedances of Hypothetical Permit Limits – Annualized Basis
(Excluding startups/shutdowns/CEMS maintenance)

Data Set	1-hour average			3-hour average		
	3.0 ppm limit	2.5 ppm limit	2.0 ppm limit	3.0 ppm limit	2.5 ppm limit	2.0 ppm limit
1997	16	24	38	12	18	44
1999	24	28	32	26	29	34
2000	36	43	48	38	46	50

In addition to performance-related issues regarding SCONOx, there are concerns regarding the demonstration of durability of the regeneration gas and damper/sealing systems, and the ability of the SCONOx system to respond to transient conditions that result in changes in turbine-exhaust NOx levels.

With respect to the damper/sealing system, there have been three different designs discussed in technical literature regarding SCONOx. Table 8.1F-10 summarizes these designs.

Table 8.1F-10
Summary of SCONOx Installations

	Federal Cogeneration[1]	Genetics Institute[1]	Proposed Future (F-class turbine)
Regeneration Gas System			
Regeneration system type	Direct hydrogen injection	External reformer	External reformer
Regen Gas Flow Rate	1520 acfm	1050 acfm	
SCOSOx (Guard Bed) Catalyst System			
Cell Density	Not installed (periodic water washing of catalyst is performed instead)		
Substrate			
Catalyst Volume		26.25 cu ft	
Space Velocity			
- Absorption		116,630	114,000
- Regeneration		6,000	4,000
Cycle Times			
- Absorption		12 min	
- Regeneration		3 min	
SCONOx Catalyst System			
Cell Density	230	230	
Substrate	Ceramic	Ceramic	
Catalyst Volume	294 cu ft	157.5 cu ft	
Space Velocity			
- Absorption	11,100	19,440	22,000
- Regeneration	275	1,000	750
Cycle Times			
- Absorption	12 min	12 min	
- Regeneration	4 min	3 min	
Damper/Seal Systems			
Number of Modules	4	5	40-60[2]
Number of Dampers	12	10	80-120[2]
Damper Type	Louver, flap type	Louver, flap type	Louver, flap type
Damper Support	End supported	Center supported	Center supported
Misc			
Seal Material/Type	316 SS, ‘S’ type	Fiberglass/stainless steel wool tadpole design	
Actuator Type	Electrical	Electrical	

Notes:
1. Stone & Webster, op cit
2. Modules are joined, four together, to form linked “shelves.”

Stone and Webster reported that the initial operation of the SCONOx system at the Genetics Institute facility resulted in a rapid loss of performance due to a lack of regeneration. This problem was traced to mechanical deficiencies, including seal and gasket leakage. Corrective actions taken included replacement of the flexible metal damper seals with tadpole seals, installation of a manual throttling valve in the gas return line, re-gasketing and re-sealing of the heat exchanger flanges, and adjustment of the damper actuators. Further changes to the overall system included adding an external reformer, adding a sulfur filter to remove sulfur from the gas that feeds the external reformer, and modifying the damper/seal system.

Although the damper/sealing system was subjected to a 101,000 cycle test (equivalent to approximately 25,000 operating hours based on 15-minute cycle times), Stone & Webster reported that a number of damper/seal design changes have been proposed by ABB based on those test results. These changes include a modification to the tadpole design to avoid excessive stress at the location where the damper blade rests on the seal, and modifications to the shaft design to preclude leaks associated with fabric failure near the shaft-seal interface.

As of the date of their report (February 22, 2000), Stone & Webster indicated that full-scale testing of the new seal design had not been performed. In particular, Stone & Webster noted that "the use of fiberglass in the temperature range of 600°F to 700°F with frequent flexing and relaxing, over the expected design period of three years, is yet to be demonstrated." Although ABB has issued a subsequent letter report addressing the concerns raised by Stone & Webster, there is no supplemental, independent engineering review in the public domain to confirm ABB's conclusions.

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

Commercial availability: It is not clear whether SCONOx technology is presently available with standard commercial guarantees for NOx levels at least as low as 2.5 ppm. A request for a copy of the guarantee for SCONOx performance from the original developers of the Otay Mesa Generating Project was rejected, and the current owners of that project have elected to use SCR technology. An excerpt of the guarantee from the system vendor to Sunlaw Energy, a co-developer of the SCONOx system, was included as an appendix to the Application for Certification for the Nueva Azalea project. However, this guarantee is between two parties with a common financial interest in the demonstration and sale of the SCONOx system, and thus is not necessarily representative of a standard commercial guarantee. Public statements by ABB Environmental, a licensee of the SCONOx system for gas turbines with a capacity greater than 100 MW, indicate that standard commercial performance guarantees will be provided for this system upon request. It is unclear, however, whether this guarantee will be passed on by the HRSG vendors and/or EPC contractors, as is standard in the industry. In fact, a potential supplier of an HRSG system for a power plant project in California has indicated, in writing, that the supplier would not back up ABB's performance guarantees or warranty claims because the supplier was "not comfortable with the scale up from the existing size of the current technology."[27] Thus, it is possible that this criterion is satisfied but, as yet, there is no publicly available documentation to support such a conclusion. The only publicly available documentation indicates that SCONOx is <u>not</u> commercially available for F-class turbines with standard commercial performance guarantees.

Reliability: To date, there have been no unqualified demonstrations of the ability of the SCONOx system to meet NOx levels of 3 ppm or lower over extended periods of time. The demonstrations at the Federal Cogeneration facility have indicated numerous circumstances under which a 3 ppm level would be exceeded (excluding startup and shutdown conditions), with data

[27] Telefax message dated June 15, 2000 from Aalborg Industries to Duke/Fluor-Daniel.

from as recently as 2000 having been evaluated. Furthermore, the SCONOx system at the Federal facility uses a different scheme for catalyst regeneration, sulfur protection, and dampers/sealing than that proposed for use in a full-scale, commercial project. The catalyst regeneration system used at the Federal facility involved direct hydrogen injection to the catalyst bed; this system appears to have been rejected for use by ABB Environmental for larger, utility-scale applications. The current sulfur protection system for the SCONOx catalyst (the SCOSOx guard bed system) was not used at the Federal facility, and the sulfur protection system used at the Federal facility (periodic water washing of catalyst elements) appears to have been rejected by ABB Environmental for larger, utility-scale applications. Finally, the end-supported damper system with metal seals used at the Federal facility appears to have been rejected by ABB Environmental for larger, utility-scale applications. Consequently, the Federal facility is not indicative of the reliability of the SCONOx system for utility-scale applications.

The SCONOx installation at the Genetics Institute facility currently uses the new designs for catalyst regeneration, sulfur protection, and dampers/sealing. However, problems associated with that facility's ability to consistently meet NOx levels lower than 2.5 ppm were reported as recently as January 2001.[28] As a result of these problems, the Genetics Institute has sought and received a permit modification that extends the SCONOx demonstration period through April 2002. The current NOx permit limit applicable to the Genetics Institute SCONOx facility is 25 ppm. Consequently, the Genetics Institute facility does not yet constitute a demonstration that the SCONOx system can reliably meet NOx levels of less than 2.5 ppm.

Furthermore, the revised damper/seal system in use at the Genetics Institute facility has not been fully tested in field service, as noted by Stone & Webster. The next-prior version of the damper/seal system, which was tested for ABB Environmental in a test facility, exhibited failures of various kinds after approximately 60,000 cycles. Improvements to the damper/seal system to address those failures have not been similarly tested (or, at least, the reports of any such tests have not been presented publicly). Since an F-class gas turbine is expected to require the use of 40-60 modules, with 40-60 pairs of dampers/seals, 40-60 shaft actuators, and approximately 2.7 million damper-cycles per turbine per year,[29] it is unclear that the performance tests conducted to date demonstrate the ability of this portion of the system to ensure compliance with sub-3 ppm NOx levels on a continuous basis.

Finally, there is no publicly available data demonstrating the performance of the SCONOx system at the SDSU facility.

Effectiveness: As discussed above, the Federal facility uses different catalyst regeneration, sulfur protection, and sealer/damper systems than those being offered for F-class turbines by ABB Environmental. Thus, it is not clear that the Federal installation can be used to demonstrate the effectiveness of the systems being proposed for larger, utility-scale projects. The SCONOx configurations at the Genetics Institute and SDSU facilities are more similar to that proposed for larger turbines; however, the Genetics Institute facility "has met or exceeded the performance requirement of 2.5 ppm [NOx] for approximately 330 hours, out of the total hours of operation of approximately 410 hours for which valid data is available."[30] This means that the 2.5 ppm NOx performance target was not met during approximately 20% of the hours within this period. As noted above, many of the exceedances of the 2.5 ppm NOx level at the Genetics Institute site were

[28] Letter dated January 15, 2001 from Genetics Institute to EPA Region I indicating that NOx emissions in excess of 2.5 ppm were experienced during 13.7% of the plant's operating time in the fourth quarter of 2000 due to control equipment problems.

[29] Calculated as 40 pairs of dampers per turbine, 2 dampers per pair, 4 cycles per damper per hour, 8400 operating hours per year: 40 x 2 x 4 x 8400 = 2,688,000 damper cycles per year per turbine.

[30] Stone & Webster, op cit

attributable to operation of the gas turbine's transient pilot. More recent data from the Genetics Institute site indicate that a NOx permit limit of 2.5 ppm would have been exceeded during 14% of operating hours in the fourth quarter of 2000 due to control equipment problems. Consequently, the available data from that site are not sufficient to conclude that NOx levels of 2.5 ppm or less can be achieved using the SCONOx system on a consistent basis, nor are the available data from the Federal site suitable for reaching such a conclusion. At a minimum, if SCONOx technology were used to achieve extremely low NOx levels, permit conditions would need to reflect the potential for frequent NOx excursions under specified conditions. As noted above, the current NOx permit limit for the Genetics Institute turbine equipped with SCONOx is 25 ppm.

Conclusion: SCONOx technology has been found to be capable of achieving NOx levels below 2.5 ppm by the South Coast AQMD and EPA. However, the presently available technical information does not support a conclusion that this technology is achieved in practice based on the applicable guidelines.

e. Select BACT

Based on the above analysis, both SCR and SCONOx-based systems are considered, in general, to be technologically capable of achieving NOx levels below 2.5 ppm, given appropriate consideration to turbine outlet NOx levels, catalyst volume (space velocity) and control system design. For both types of systems, some provision will be necessary to accommodate short-term excursions above permit limits, and for both types of systems, particular attention to CEMS design will be necessary to ensure that low permit limits can be monitored on a continuous and accurate basis.

Based on this information, BACT for NOx is considered to be the use of either SCR or SCONOx systems to achieve NOx levels not higher than 2.5 ppm on a 1-hour average basis, or 2.0 ppm on a 3-hour average basis. The Project proposes to use SCR technology to meet a NOx level of 2.5 ppm on a 1-hour average basis, and 2.0 ppm on an annual average basis. Consequently, the Project is consistent with BACT requirements.

2. <u>Control of Ammonia Emissions</u>

a. Identify all control technologies

Ammonia emissions result from the use of ammonia-based NOx control technologies. Consequently, only an abbreviated discussion of these technologies is restated here.

There are three basic means of controlling NOx emissions from combustion turbines: wet combustion controls, dry combustion controls, and post-combustion controls. These technologies were discussed above.

Water and steam injection are control technologies that, for large gas turbines, have been largely superseded by dry low-NOx combustors, due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of this technology. Since the project proposes to use dry low NOx combustors, no further discussion of water injection, steam injection, or dry low NOx combustors is necessary.

b. Eliminate technically infeasible options

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

c. Rank remaining control technologies by control effectiveness

SCONOx results in no emissions of ammonia, while SCR results in ammonia slip levels of up to 10 ppm. The following discussion evaluates potential ammonia slip limits of 10 ppm, 5 ppm, 2 ppm, and 0 ppm. The latter limit would be achievable, at the present time, only through the use of

SCONOx technology.

d. Evaluate most effective controls and document results

SCR has been achieved in practice at numerous gas turbine installations throughout the world. Although there are a large number of gas turbines equipped with SCR systems, there are relatively fewer operating systems that are designed to meet low NOx permit limits of 3.0 ppm or less. 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., 2.5 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 2.5 ppm. During the early period of performance, ammonia slip from an SCR catalyst is typically less than 1-2 ppm, and will approach the guarantee level only towards the end of the catalyst life.

Early SCR installations, as well as some later installations, have been associated with ammonia slip levels of 10 ppm. In August 1999, the California Air Resources Board adopted a BACT guideline for large gas turbines that proposed to limit ammonia slip to not more than 5 ppm. Ammonia slip levels of 2 ppm have been required in several permits issued in the eastern United States. However, these permits have typically been associated with higher NOx levels than are proposed here. In particular, the 2 ppm ammonia slip limits have been proposed in conjunction with NOx levels that range between 2.0 and 3.5 ppm, depending on operating mode. Although the Project is proposing a 1-hour average NOx limit of 2.5 ppm, the facility is also proposing an annual average goal of 2.0 ppm.

Finally, SCONOx has the potential to achieve this low a NOx level without any ammonia slip.

Consequently, the following discussion compares the use of SCR with a 10 ppm ammonia slip level with SCONOx to meet comparable NOx levels, but without any ammonia slip.

SCR technology is available with standard commercial guarantees with ammonia slip levels of 10, 5, and 2 ppm, in conjunction with NOx levels at least as low as 2 ppm.

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. However, this demonstration has not been made in conjunction with NOx levels as low as 2.5 ppm. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.

The SJVUAPCD's web site lists two SCR-based BACT determinations for ammonia slip from the mid-90s. These projects were permitted at 20 and 25 ppmvd NH_3 @ 15% O_2. More recent permit decisions have included 10 ppm ammonia slip levels, consistent with the level proposed for the Project.

One of these more recent SCR-based BACT determinations for ammonia slip is for the La Paloma Generating project, which was approved by the District in October 1999. This project is required to meet a 10 ppm ammonia slip limit on a 24-hour average basis in conjunction with a 2.5 ppm NOx limit on a 1-hour average basis.

These permits indicate that, as recently as one year ago, ammonia slip limits of 10 ppm were considered best available control technology. The rapid changes during the last year are indicative of increasing confidence of SCR system vendors in sustaining low ammonia slip rates in conjunction with low NOx emission rates. However, given the lack of any real-world demonstration of these low NOx and ammonia slip levels at the present time, BACT for ammonia slip using SCR-based controls is still considered to be 10 ppm for this project.

Consequently, if an SCR-based control system is selected, the associated limit for ammonia slip should be an emission limit of 10 ppm.

Since SCONOx 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 a SCONOx 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, even though an oxidation catalyst is not proposed for the Project, because the performance of the SCR and oxidation catalyst systems is theoretically comparable to that proposed for SCONOx with respect to NOx and CO emission levels for this project.)

As shown in Tables 8.1F-11a through 11d, the results of this analysis indicate that the incremental cost/effectiveness of the SCONOx system for the purpose of reducing ammonia emissions is nearly $50,000 per ton.

The SJVUAPCD publishes cost/effectiveness criteria for use in performing BACT analyses. The BACT cost/effectiveness threshold for PM_{10}, $5700/ton, is used to provide a reference for the calculated cost/effectiveness of SCONOx as an ammonia control device. (The SMAQMD has an old, draft BACT cost/effectiveness guideline that contains a cost/effectiveness threshold of $2600/ton for PM_{10}.) Since ammonia is an unregulated precursor to PM_{10}, this value is used to represent a BACT cost/effectiveness threshold for ammonia control.

While this value is not, by itself, determinative, it indicates that the cost/effectiveness of using SCONOx to eliminate ammonia emissions is well in excess of the cost that is normally required for the control of PM_{10} in BACT determinations in the Central Valley, where the state and/or federal PM_{10} air quality standards are exceeded.

e. Select BACT

Based on the above information, an appropriate ammonia slip limit is believed to be 10 ppm. SCONOx has the potential to eliminate ammonia emissions; however, this candidate technology was rejected for the reasons discussed above.

The Project proposes to use SCR technology to meet an ammonia slip limit of 10 ppm on a 3-hour average basis, in conjunction with NOx levels of 2.5 ppm on a 1-hour average basis and 2.0 ppm on an annual average basis. Consequently, the Project’s proposal is consistent with the appropriate level for ammonia emissions.

Table 8.1F-11a
SCR Costs (per gas turbine/HRSG)

Description of Cost	Cost Factor	Cost ($)	Notes
Direct Capital Costs (DC):			
Purchased Equip. Cost (PE):			
Basic Equipment:			
Auxiliary Equipment: HRSG tube/fin modifications			
Instrumentation: SCR controls			
Ammonia storage system:			
Taxes and freight:			
PE Total:		$1,620,000	1
Direct Install. Costs (DI):			
Foundation & supports:	0.08 PE	$129,600	2
Handling and erection (included in PE cost):		$0	1
Electrical (included in PE cost):		$0	1
Piping (included in PE cost):		$0	1
Insulation (included in PE cost):		$0	1
Painting (included in PE cost):		$0	1
DI Total:		$129,600	
Site preparation for ammonia tanks		$10,000	1
DC Total (PE+DI):		$1,759,600	
Indirect Costs (IC):			
Engineering:	0.10 PE	$162,000	2
Construction and field expenses:	0.05 PE	$81,000	2
Contractor fees:	0.10 PE	$162,000	2
Start-up:	0.02 PE	$32,400	2
Performance testing:	0.01 PE	$16,200	2
Contingencies:	0.05 PE	$81,000	1
IC Total:		$534,600	
Less: Capital cost of initial catalyst charge		-$975,000	
Total Capital Investment (TCI = DC + IC):		$1,319,200	
Direct Annual Costs (DAC): 0.5 hr/SCR per shift	hr/yr: 4,380		
Operating Costs (O): sched. (hr/day 24 day/week: 7	wk/yr: 52		
Operator: hr/shift: 1.0 operator pay ($/hr):	39.20	$42,806	2
Supervisor: 15% of operator		$6,421	2
Maintenance Costs (M): 0.5 hr/SCR per shift			
Labor: hr/shift: 1.0 labor pay ($/hr):	39.2	$42,806	2
Material: % of labor cos 100%		$42,806	2
Utility Costs:			
Perf. loss: (kwh/unit): 347.6			1
Electricity cost ($/kwh): 0.0336 Performance loss cost penalty:		$102,311	5
Ammonia based on 153 lbs/hr of 24.5% wt aqueous ammonia, $0.05/lb		$73,883	1, 4
Catalyst replace: based on 3 year catalyst life		$325,000	1
Catalyst dispose: based on 2,750 ft^3 catalyst, $15/$ft^3$, 3 yr. Life		$13,750	1
Total DAC:		$649,784	
Indirect Annual Costs (IAC):			
Overhead: 60% of O&M		$80,904	2
Administrative:	0.02 TCI	$26,384	2
Insurance:	0.01 TCI	$13,192	2
Property tax:	0.01 TCI	$13,192	2
Total IAC:		$133,672	
Total Annual Cost (DAC + IAC):		$783,456	
Capital Recovery (CR):			
Capital recovery: interest rate (%) 10			
period (years): 15	0.1315	$173,440	2
Total Annualized Costs		$956,897	

Table 8.1F-11b

Oxidation Catalyst Costs (per gas turbine/HRSG)

Description of Cost	Cost Factor	Cost ($)	Notes
Direct Capital Costs (DC):			
Purchased Equip. Cost (PE):			
Basic Equipment:			
Auxiliary Equipment: HRSG tube/fin modifications			
Instrumentation: oxidation cat. Controls			
Taxes and freight:			
PE Total:		$725,000	1
Direct Install. Costs (DI):			
Foundation & supports:	0.08 PE	$58,000	2
Handling and erection (included in PE cost):		$0	1
Electrical (included in PE cost):		$0	1
Piping (included in PE cost):		$0	1
Insulation (included in PE cost):		$0	1
Painting (included in PE cost):		$0	1
DI Total:		$58,000	
DC Total (PE+DI):		$783,000	
Indirect Costs (IC):			
Engineering:	0.10 PE	$72,500	2
Construction and field expenses:	0.05 PE	$36,250	2
Contractor fees:	0.10 PE	$72,500	2
Start-up:	0.02 PE	$14,500	2
Performance testing:	0.01 PE	$7,250	2
Contingencies:	0.05 PE	$36,250	1
IC Total:		$239,250	
Less: Capital cost of initial catalyst charge		-$350,000	
Total Capital Investment (TCI = DC + IC):		$672,250	
Direct Annual Costs (DAC):	hr/yr: 4,380		
Operating Costs (O): sched. (hr/day 24	day/week: 7 wk/yr: 52		
Operator: hr/shift: 0.0	operator pay ($/hr): 39.20	$0	2
Supervisor: 15% of operator		$0	2
Maintenance Costs (M): 0.5 hr/oxidation cat. per shift			
Labor: hr/shift: 0.0	labor pay ($/hr): 39.2	$0	2
Material: % of labor cos 100%		$0	2
Utility Costs:			
Perf. loss: (kwh/unit): 172.5			1
Electricity cost ($/kwh): 0.0336	Performance loss cost penalty:	$50,773	5
Catalyst replace: based on 3 yr. Life		$116,667	1
Catalyst dispose: based on 240 ft^3 catalyst, $15/$ft^3$, 3 yr. Life		$1,200	1
Total DAC:		$168,640	
Indirect Annual Costs (IAC):			
Overhead: 60% of O&M		$0	2
Administrative:	0.02 TCI	$13,445	2
Insurance:	0.01 TCI	$6,723	2
Property tax:	0.01 TCI	$6,723	2
Total IAC:		$26,890	
Total Annual Cost (DAC + IAC):		$195,530	
Capital Recovery (CR):			
Capital recovery factor (CRF): interest rate (%): 10			
period (years): 15	0.1315	$88,383	2
Total Annualized Costs		$283,913	

Table 8.1F-11c

SCONOx Cost and Cost/Effectiveness (per gas turbine/HRSG)

Description of Cost		Cost ($)	Notes
Direct Capital Costs			
	Capital (less cost of initial catalyst charge)	$3,900,000	3, 7
	Installation	$1,700,000	3
Indirect Capital Costs			
	Engineering	$200,000	3
	Contingency	$250,000	3
	Other	-	
Total Capital Investment		$6,050,000	
Direct Annual Costs			
	Maintenance	$250,000	3
	Ammonia	-	3
	Steam/Natural Gas	$400,000	3
	Pressure Drop	$226,000	3
	Catalyst Replacement (based on 3-yr catalyst life)	$3,033,333	7, 8
	Catalyst Disposal	$0	
Total Direct Annual Costs		$3,909,333	
Indirect Annual Costs			
	Overhead	-	3
	Administrative, Tax & Insurance	$225,000	3
Total Indirect Annual Costs		$225,000	
TOTAL ANNUAL COST		$4,134,333	
Capital Recovery Factor		0.1315	2
Capital Recovery		$795,416	
TOTAL ANNUALIZED COSTS		$4,929,750	

SCONOx Ammonia Cost Effectiveness (per gas turbine/HRSG)

Description of Cost		Cost ($)	Notes
SCONOx Annualized Costs		$4,929,750	
SCR Annualized Costs		$956,897	
Oxidation Cat. Annualized Costs		$283,913	
SCR/Oxidation Cat. Annualized Costs		$1,240,809	
Incremental Annualized Costs		$3,688,940	
Annual Ammonia Emissions with SCR (tons/yr)		74.02	6
Annual Ammonia Emissions with SCONOx (tons/yr)		0	
Reduction in Ammonia Emissions (tons/yr)		74.02	
SCONOx COST EFFECTIVENESS ($/ton removed)		$49,836	

Table 8.1F-11d

Notes: SCONOx Ammonia Cost Effectiveness Analysis

Note No.	Source
1	Based on information from Duke/Fluor Daniel.
2	From EPA/OAQPS Control Cost Manual. EPA-450/3-90-006. January 1990.
3	From April 12, 2000 letter from ABB Alstom Power to Matt Haber EPA Region IX (SCONOx capital cost of $13,000,000).
4	Based on anhydrous ammonia cost of $450/ton.
5	Based on current average price of power in the project area.
6	Based on G.E. 7FA Gas Turbine/HRSG operating at 100% load, 43 deg. F ambient, duct burner on, ammonia slip of 5 ppm @ 15% O2, operating 24 hours per day, 365 days per year.
7	Based on information from May 8, 2000 "Testimony of J. Phyllis Fox, Ph.D. on Behalf of the California Unions for Reliable Energy on Air Quality Impacts of the Elk Hills Power Project", cost of replacement catalyst for SCONOx is 70% of initial capital investment.
8	Based on information from May 5, 2000 letter from ABB Alstom Power to Bibb and Associates indicating that SCONOx catalyst life is guaranteed for a 3-year period.