4.0 Combustion Turbine NO_x BACT Analysis

The objective of this analysis is to determine the BACT for NO_x emissions from the simple cycle combustion turbine, considering the unique aspects of Combustion Turbine Unit 4. These unique aspects are the following:

- Fuel oil fired only.
- Daily start-ups (over 200 per year).
- Extended hours of operation on oil.
- Need for high reliability because of limited transmission connection.
- Seaside island location.

Unless otherwise noted, the NO_x emission rates described in this section are corrected to 15 percent oxygen.

4.1 NO_x BACT/LAER and Technology Review

A summary of the pertinent BACT/LAER and other NO_x control technology decisions for simple cycle combustion turbines burning only fuel oil is attached in Appendix A. A review of BACT/LAER and other NO_x control technology decisions for simple cycle combustion turbines firing fuel oil as a primary or backup fuel has identified water injection as the primary form of NO_x control while firing oil. This review further indicates that selective catalytic reduction (SCR) is being used on only two simple cycle projects where oil is permitted, and in both of these situations, oil has been fired only in minimal amounts (750 hours over 2 years for one project and 200 hours per year for the other project) and represents very limited operational experience. Discussion of the relevant history of SCR on fuel oil units is included in Subsection 4.2.6.

4.2 Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. NO_x emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

Nitrogen oxide control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NO_x formed in the combustion process.

A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The six different types of emission controls reviewed by this BACT analysis are as noted below.

- In-Combustor Type:
  - Water/Steam Injection.
  - Dry Low-NO_x (DLN) Burners.
  - Xonon.
- Post-Combustion Type:
  - Selective Non-Catalytic Reduction (SNCR).
  - $SCONO_x$.
  - Selective Catalytic Reduction (SCR).

The rationale behind whether the above technologies are evaluated as NO_x control for BACT is included in the following subsections.

4.2.1 Water or Steam Injection

NO_x emissions from Combustion Turbine Unit 4 can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine. Since the combustion turbine NSPS was last revised in 1982, manufacturers have improved combustion turbine tolerances to the water necessary to control NO_x emissions below the current NSPS level. A limit exists, however, on the amount of water that can be injected into the system before reliability of the combustion turbine is seriously degraded and operational life is affected. This type of control can also be counterproductive with regard to carbon monoxide (CO) and volatile organic compound (VOC) emissions that are formed as a result of incomplete combustion.

The development of dry low-NO_x burners has replaced the use of wet controls, except for certain cases such as oil firing. Since Unit 4 will fire only low sulfur fuel oil, water injection will be considered for control of NO_x formation in this BACT analysis.

4.2.2 Dry Low-NO_x Burners

NO_x can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low-NO_x (DLN) burners as a way to reduce flame temperature is one

common NO_x control method. These combustor designs are called DLN burners because, when firing fuel, injecting water into the combustion chamber is not necessary to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion system as the state of the art for NO_x controls in combustion turbines. This method is exclusively utilized when firing natural gas. This application will, therefore, not be reviewed further as a BACT alternative for the fuel oil fired Combustion Turbine Unit 4.

4.2.3 XONON

Another form of in-combustor control is XONON. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2,700°F at full power generation, which significantly reduces NO_x emissions without raising, and possibly even lowering, emissions of CO and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine. This emerging technology is being commercialized by several joint ventures that Catalytica has with turbine manufacturers.

Although this technology has been applied to small turbines, such as a Kawasaki M1A-13X (1.5 MW) combustion turbine, it has not been applied to utility size combustion turbines or combustion turbines firing fuel oil, such as proposed for the Combustion Turbine Unit 4. It is expected that application of this technology to utility size combustion turbines will require a period of "scale up" and testing before it can be determined that this technology can demonstrate in practice a given NO_x emission limit. Because this technology has not been applied to utility size combustion turbines firing fuel oil, it is not considered to be technically feasible for Combustion Turbine Unit 4. As such, this method of combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

4.2.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injector location and temperature to achieve proper reagent/flue gas mixing for maximum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x reduction efficiency. The optimum temperature range for injection of ammonia or urea is 1,500° to 1,900°F. The NO_x reduction efficiency of

an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia emissions (ammonia slip). Operation above the temperature window results in increased NO_x emissions.

Because the exhaust temperature at the exit of the combustion turbine proposed for this project (approximately 837°F) is less than the optimum temperature range for the application of this technology, it is not technically feasible to apply this technology to this project and it will be eliminated from further evaluation in this BACT analysis.

4.2.5 SCONOx

A second, relatively new post-combustion technology from Goal Line Environmental Technologies in conjunction with ABB Alstom Power is $SCONO_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. The South Coast Management District in California recently determined LAER for NO_x to be 2.0 ppmvd at 15 percent O_2 using this technology for gas fired combustion turbines.

The $SCONO_x$ system utilizes hydrogen (H_2) (which is created by reforming natural gas) as the basis for a proprietary catalyst regeneration process. The system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize both NO_x and CO, thereby reducing total plant emissions. CO emissions are decreased by the oxidation of CO to carbon dioxide (CO_2). The catalyst is installed in the flue gas at a point where the temperature is between 300° to 700°F. ABB Alstom/Goal Line guarantees the performance of the catalyst for 3 years. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst.

The $SCONO_x$ catalyst is very susceptible to fouling by sulfur in the flue gas. The impact of sulfur can be minimized by a sulfur absorption $SCOSO_x$ catalyst. The $SCOSO_x$ catalyst is located upstream of the $SCONO_x$ catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the $SCOSO_x$ catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The $SCOSO_x$ catalyst is regenerated along with the $SCONO_x$ catalyst.

The $SCONO_x$ catalyst will require that it be re-coated or "washed" every 6 months to 1 year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the $SCOSO_x$ catalyst. The "washing" consists of removing the catalyst modules from the unit and placing each module in a potassium carbonate reagent tank, which is the active ingredient of the catalyst. The $SCOSO_x$ catalyst will also require washing, but due to limited operating experience with the $SCOSO_x$ catalyst, it is

uncertain how often this will be required. However, it is expected that the $SCOSO_x$ catalyst will require annual washing.

The current $SCONO_x$ catalyst technology is in its second generation. The first generation operated for approximately 10 months on a small LM-2500 combined cycle combustion turbine unit before the $SCONO_x$ system was taken out of service because of poor regeneration gas distribution.

The USEPA has stated its concerns (November 19, 1999 letter from USEPA Region I) with the technical uncertainties of the $SCONO_x$ system and was apprehensive about applying $SCONO_x$ technology to large combined cycle turbines that burn primarily natural gas. The combustion turbine proposed for this project is approximately 48 MW, which is within the operating range (32 MW) of the $SCONO_x$ system currently operating at the Federal Cold Storage Cogeneration facility in California. However, Combustion Turbine Unit 4 will fire low sulfur fuel oil for which $SCONO_x$ has no applications.

As discussed above, the $SCONO_x$ technology may have future promise. The application of this technology is currently limited to natural gas combined cycle combustion turbine units under 40 MW. This $SCONO_x$ method of post-combustion control is not considered technically feasible and, therefore, is not included in this BACT analysis to control NO_x emissions.

4.2.6 Selective Catalytic Reduction

Another post-combustion method is selective catalytic reduction (SCR). The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades, ammonia slip will increase. As the ammonia slip approaches the permitted ammonia emissions level, catalyst replacement will be required to maintain compliance with the permit.

4.2.6.1 SCR Operational Issues While Firing Fuel Oil. The ability to promote the chemical reaction converting NO_x and NH_3 to nitrogen and water of a catalyst degrades over time in all applications. The reduced activity, reduced effectiveness, and degradation of the SCR catalyst while firing oil in a simple cycle unit is greatly increased in comparison to standard combined cycle natural gas applications. In addition, frequent start-ups reduce activity, reduce effectiveness, and increase degradation of the catalyst. A marine environment may also accelerate reduced effectiveness and increased degradation. Ultimately, such degradation and reduced effectiveness lead to the requirement to replace catalyst in the reactor vessel at more frequent intervals than a similar application firing natural gas or without frequent start-ups.

The primary causes of SCR catalyst degradation include fouling and sooting, mechanical failures, thermal degradation, and poisoning, as more fully described below.

4.2.6.1.1 Fouling and sooting. Fouling occurs when solids build up on the catalyst surface, blocking the small pores of the active sites. Due to the constituents of distillate fuel oil, the unit produces a sooty residue on the SCR catalyst during times of incomplete combustion. While this occurs during normal operations, it is more pronounced during frequent start-ups, which are expected with the Stock Island Combustion Turbine Unit 4. A sooty residue has much the same affects as fouling. The majority of SCR applications utilizing fuel oil are based upon the unit primarily firing natural gas and being limited in operating hours while firing fuel oil. These applications, due to a limited number of hours on fuel oil firing, would have few startup scenarios on oil, thereby minimizing the impacts of the secondary fuel oil firing on the SCR catalyst. Combustion Turbine Unit 4 can be expected to have startups in excess of 200 times within a calendar year and would, therefore, experience problems because of sooty residue.

Another form of fouling is ammonium bisulfate formation. This is a sticky substance, which can form when ammonia is injected in the presence of SO_3 at low flue gas temperatures as a result of maldistribution of the tempering air. Most of the ammonium bisulfate deposits would be removed from the catalyst surface when flue gas temperature is increased above approximately 660° F upon correction of the distribution problem, so permanent fouling of the catalyst by ammonium bisulfate should be minimal. The ammonia bisulfate is removed through evaporation, which can take several hours.

4.2.6.1.2 Mechanical failures. Mechanical failures are cracks or debonding of the catalyst from the substrate material, leaving small voids or channels of reduced catalyst in the SCR grid. Mechanical failures can occur from thermal stresses associated with frequent starts (which are expected for the Stock Island Combustion Turbine Unit 4), as well as dynamic forces on the modules. This could result in catalyst deficient channels, which allows the exhaust gas to bypass the active catalyst sites.

4.2.6.1.3 Thermal degradation. The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. Vanadium/titanium catalysts have been used on the majority of SCR system installations. The flue gas temperature range for optimum SCR operation using a conventional vanadium/titanium catalyst is approximately 600° to 750°F. At temperatures above 800°F, permanent damage to the vanadium/titanium catalyst can occur. Either a zeolite catalyst (high temperature) or dilution tempering air is required to minimize the impact to the SCR vanadium/titanium catalyst. The flue gas temperature at the outlet of Combustion Turbine Unit 4 will typically range from 700° to 860°F, which

will require the application of dilution air tempering with utilization of the vanadium/titanium catalyst.

4.2.6.1.4 Poisoning. A number of alkali metals and trace elements, which are expected in the Combustion Turbine Unit 4 fuel oil and which are more prevalent in oil than in gas, will poison the catalyst, significantly reducing reactivity and resulting in a much shorter life span. Known catalyst poisons are as follows:

- Arsenic
- Calcium
- Potassium
- Sodium
- Lead
- Cadmium
- Beryllium
- Chromium
- Copper
- Mercury
- Manganese
- Nickel
- Thorium
- Uranium

These poisoning effects do not occur suddenly; they are a continual process over the entire life of the catalyst. For example, AP-42 identifies arsenic as being 50 times greater in fuel oil than in natural gas. Arsenic, the major poison when in the form of gaseous arsenic oxide, can be deposited on catalyst surfaces, clogging small pores of the catalyst. This limits the transport of the ammonia-NO_x mixture to the activity sites. This effect can be somewhat minimized by enlarging the pores of the catalyst to limit the blocking of active sites. However, arsenic, as well as the other poisons listed, can chemically attack (neutralize) the active sites on the catalyst surface and reduce catalyst effectiveness over time.

Another form of poisoning is caused by sodium. This has occurred in two installations. The first occurrence was at a plant with a coastal environment. It was believed that the source of the sodium originated from sea air or an aqueous ammonia supply. The second occurrence was attributed to sodium in a low quality aqueous ammonia supply. This will be greatly exacerbated at the Stock Island site due to the geographical location of the facility and a great amount of salt in the air.

While some of these operational issues can be minimized through design features, because of the daily cycling, extensive oil use, and a severe marine environment, the

Stock Island Combustion Turbine Unit 4 can be expected to need frequent catalyst replacement. The daily cycling while firing fuel oil is a significant contributor to the degradation categories of sooting, poisoning, mechanical failures, and thermal degradation. Ultimately, the need to replace catalyst will be a function of the SCR system's ability to meet the requisite NO_x and ammonia slip permit requirements.

4.2.6.2 Relevant Operating History. As indicated in Appendix A, the application of SCR on simple cycle combustion turbines firing oil is very limited. The following is a discussion of the test programs and units which have actually operated using SCR while firing fuel oil.

4.2.6.2.1 EPRI Fuel Oil Pilot Test. The Electric Power Research Institute (EPRI) has performed an analysis of SCR operation on fuel oil in both a combined cycle and simple cycle configuration, and confirmed these expected problems. The analysis report was performed in 1997 (TR-108169). A test pilot program was initiated on a slip stream SCR system at the Maalea Generating Station owned by Maui Electric Co. The LM2500 unit fired low sulfur fuel oil with less than 0.04 percent sulfur by weight. The results of the pilot plant indicated that the SCR system experienced long term operating problems for both the combined and simple cycle arrangement. For both configurations in the pilot test plant, the SCR system experienced greater than expected catalyst deactivation rates and excessive oxidation of SO_2 to SO_3. At that time, EPRI recommended that simple cycle SCR oil fired applications were not a feasible technology.

4.2.6.2.2 Shoreham Electric Generating Station – Long Island, New York. The Shoreham Electric Generating Station on Long Island, New York includes two simple cycle combustion turbines permitted to fire fuel oil only with the use of water injection and SCR for control of NO_x emissions. This facility is located in an ozone non-attainment area and would have been subject to LAER for NO_x control if New Source Review were required. The permit limits annual NO_x emissions to 22.5 tons per year, and the permit states that it does not permit the operation of a major electric generating facility. Thus, it is presumed that the applicant decided to install SCR controls as a means to avoid New Source Review. Because the facility was not subject to PSD review, a BACT analysis was not required as part of the permit application for the facility. The effective date of this facility's "Air state facility permit for a new facility (preconstruction permit)" is January 10, 2002.

Based on owner provided information, additional catalyst in excess of design was added to address concerns about reliability. Based on information contained on the USEPA Airmarkets Web site, total operation of these units through the first quarter of 2004 was less than 750 operating hours, which equates to approximately 1 month of operation. This data, along with the permit limit on annual NO_x emissions, points to the

limited use of these units. A copy of the Shoreham Electric Generation Station Permit is included in Appendix B.

4.2.6.2.3 Puget Sound Energy Fredonia – Mount Vernon, Washington. The Puget Sound Energy (PSE) Fredonia facility combustion turbines are two Pratt & Whitney FT8 (Twin Pack) units, which began operation in 2001. These units were permitted in 2003 (after the fact) to fire natural gas or distillate fuel and have a NO_x limit of 5 ppmvd, corrected to 15 percent O_2, for both fuels. Based on a conversation with an Environmental Manager at PSE, each of the units has approximately 2,000 to 3,000 hours of run time with a couple hundred hours of oil firing run time. Therefore, while these units are permitted to fire either natural gas or distillate oil, they have a limited number of hours of distillate oil firing to date.

4.2.6.2.4 PREPA – Cambalache Power Plant. The Puerto Rico Power Authority (PREPA) Cambalache Power Plant, located in Puerto Rico was originally installed with SCR catalyst in 1997, but due to repeated operation failures, the USEPA approved the removal of the SCR system in 2000 and indicated that SCR was not BACT for these units. This failure occurred more than 20 years after the first installation of SCR on oil fired utility boilers. Notwithstanding the advances in technology, the application of SCR on this unit failed after just 2 months of oil firing. Numerous attempts to correct the problems were unsuccessful. The units currently control NO_x with steam injection down to 42 ppmvd. A further discussion and a copy of the compliance order are attached as Appendix C.

4.2.6.2.5 Vendor Experience. FMPA has found no SCR packager or catalyst manufacturer that has had equipment operating in a situation like the proposed Stock Island project, a simple cycle combustion turbine firing on fuel oil only in a marine environment with daily starts and extended hours.

4.2.6.2.6 Summary of Operational Experience. As indicated above, no simple cycle combustion turbines have successfully operated while using SCR and firing fuel oil for more than 750 hours. No known simple cycle combustion turbine utilizing SCR and firing fuel oil has operated anywhere close to the 8,760 hours per year proposed for Stock Island Combustion Turbine Unit 4, leading to a lack of needed operational experience on which to project catalyst life. Nor has any such unit successfully operated in a severe tropical marine environment such as the Stock Island Power Plant.

4.2.6.3 Recent Permitting Actions.

4.2.6.3.1 PREPA San Juan Repowering Project. From the USEPA BACT/RACT/LAER Clearinghouse, the PREPA San Juan Repowering Project PSD permit was issued in March 2000. This project included the addition of two 232 MW combined cycle combustion turbines. The combustion turbines were to be fired with fuel oil only. The draft PSD permit for the repowering project included BACT as being the

use of an SCR system to control NO_x emissions. However, after further review, the USEPA determined that BACT for this project was steam injection for NO_x control. This determination was outlined in an USEPA press release dated March 24, 2000 (copy included in Appendix D). This press release included the following statements regarding the use of an SCR system with an oil fired only combustion turbine:

> "In its draft permit, proposed in March 1999, EPA included Selective Catalytic Reduction (SCR), which uses an ammonia injection system to reduce nitrogen oxide emissions, and steam injection. However, new data indicate that, on oil-fired turbines, SCR cannot consistently achieve the expected reductions in nitrogen oxide emissions. As a result, EPA has removed the SCR requirement and will instead require PREPA to install special burners, called "low NO_x burners," on the four old boilers at its facility. PREPA would still use steam injection on its turbines."
>
> "After carefully considering the feasibility of using SCR on an oil-fired plant and reviewing public comments, the choice to remove SCR was clear," said Jeanne M. Fox, EPA Regional Administrator. "We want to ensure that PREPA uses the most reliable pollution controls. Steam injection systems and low NO_x burners are both tried and true nitrogen oxide controls."

4.2.6.3.2 Virgin Islands Water and Power Authority (VIWAPA) Unit 22. The VIWAPA received a PSD construction permit from USEPA Region 2 in January 2001 for the installation of Unit 22. The PSD construction permit allowed for the installation of Unit 22, a 24 MW United Technologies FT8-1 Power Pac gas turbine at the VIWAPA St. Thomas facility. Unit 22 will operate in simple cycle mode without any secondary heat recovery. The only permitted fuel for Unit 22 is No. 2 fuel oil with a maximum sulfur content of 0.2 percent sulfur by weight. The VIWAPA St. Thomas facility was an existing PSD major stationary source. Unit 22 was PSD affected for NO_x, SO_2, CO, PM_{10}, and VOCs, and was, therefore, required to employ BACT to control emissions of these pollutants. For NO_x emissions, BACT was determined to be the use of water injection. The PSD permit includes a NO_x emissions limit of 42 ppmvd, corrected to 15 percent oxygen. A copy of the VIWAPA Unit 22 Permit is included in Appendix E.

4.2.6.3.3 Virgin Islands Water and Power Authority (VIWAPA) Unit 23. On March 5, 2004, the USEPA announced approval of an exemption of the Clean Air Act for the Territory of the United States Virgin Islands. This exemption allowed for the construction, but not operation, of Unit 23 at the VIWAPA St. Thomas facility. This exemption was sought by the US Virgin Islands Governor, on behalf of VIWAPA, so that

VIWAPA could proceed as quickly as possible with the construction of Unit 23, a 36 MW simple cycle combustion turbine. It was stated that the petitioner did not seek any exemption from obtaining a PSD permit and meeting all emission control and air quality related obligations under the CAA prior to beginning operation of the new turbine. It was also stated that the exemption will not affect any emission or any air quality requirements and that the new turbine will be held to the same emission limitations as a similar source built in another area which is attaining the NAAQS.

USEPA Region 2 issued a PSD permit for VIWAPA Unit 23 on September 8, 2004. The PSD permit lists Unit 23 as a 36 MW General Electric Frame 6 combustion turbine. The type of fuel is limited to No. 2 fuel oil or distillate fuel oil with a sulfur content of no more than 0.15 percent sulfur by weight and a nitrogen content of no more than 1,000 ppm nitrogen by weight. BACT for NO_x is the use of water injection to control NO_x emissions. The permit includes various NO_x limits, including a NO_x limit of 135 lb/hr, a NO_x limit of 84 ppmvd, corrected to 15 percent oxygen, and a NO_x limit based on a monthly average of 42 ppm with an adjustment based on the nitrogen content of the fuel oil. Based on a discussion with USEPA Region 2, the USEPA decided early on in the permitting process that SCR would not be required and identified to the applicant that they did not have to address SCR as part of their permit application. Thus, the permittee did not evaluate SCR as part of the BACT analysis. A copy of the VIWAPA Unit 23 permit and PSD Waiver is included in Appendix F.

4.2.6.3.4 Commonwealth Chesapeake Power Station – New Church, Virginia. The Commonwealth Chesapeake Power Station functions as a peaker plant with seven LM6000 simple cycle combustion turbines firing fuel oil only. This facility was permitted by the Virginia Department of Environmental Quality. The facility was issued a PSD permit in October 2000. CT 1 through 3 were installed in 2000 and CT 4 through 7 were installed in 2001. BACT for NO_x for these units was determined to be the use of water injection. The following summary is taken from a document discussing the BACT decision for the Commonwealth Chesapeake Power Station:

> "NO_x average cost for HT (high temperature) SCR control was reasonable at $1,452 per ton; however, the incremental cost at $12,354 per ton was judged too costly for BACT. Besides the large incremental cost, HTSCR system for oil fired simple cycle turbines is still in the design stage. The one permitted turbine facility that tried HTSCR system for oil fired turbines in Puerto Rico failed. USEPA, Region II removed the SCR system in the revised permit issued in 2000 – leaving control to water injection. Tentative technology, high cost, and ammonia emissions do not make HTSCR a BACT selection for the CCC peaker plant project. BACT selected as the use of water injection for NO_x control."

Permitting information for the Commonwealth Chesapeake Power Station is located in Appendix G.

4.2.6.3.5 City of Tallahassee Arvah B. Hopkins Station – Tallahassee, Florida. The Florida Department of Environmental Protection (FDEP) published an intent to issue an air construction permit on September 9, 2004, for the installation of two LM6000 simple cycle combustion turbines at the City of Tallahassee Arvah B. Hopkins Station. The draft permit for these units allows for the use of natural gas and fuel oil in the combustion turbines, with annual hours of operation limited to 5,840 hours of operation per year for each turbine, of which 4,000 hours may be with fuel oil. The draft permit requires the use of SCR for NO_x control with a NO_x emissions limit of 5 ppmvd corrected to 15 percent O_2 and an ammonia slip limit of 10 ppmvd at 15 percent O_2. As indicated in the permit application BACT economic analysis for this construction permit, the catalyst guarantee is for 1,500 hours per year of fuel oil firing. It appears that this limited fuel oil firing catalyst guarantee is reflected in the BACT economic analysis, where a catalyst life of less than 1 year is used. Naturally, since this installation is still in the permitting phase and construction has not begun, there is no SCR operational information associated with these units.

4.2.6.3.6 Permitting Summary. Out of the 95 projects identified in Appendix A, only 4 include the use of SCR. In each of these cases, SCR was voluntarily proposed by the permittee. As indicated in Appendix A, water injection continues to be the predominant method of controlling NOx emissions while firing fuel oil in a combustion turbine. For example, as recently as September 2004, EPA determined water injection was BACT for a simple cycle combustion turbine firing fuel oil.

4.2.6.4 SCR Summary. The industry, and the USEPA itself in previous rulings as noted above, has indicated reservations and concerns regarding the capability for SCR systems to provide reliable NO_x control on a unit such as Combustion Turbine Unit 4 (i.e., fuel oil only operation with a large number of operating hours each year and with frequent start-ups and shut downs in a marine environment). The only oil fired combustion turbine units that are operating with SCR have very limited operated hours.

Although some SCR vendors appear willing to offer guarantees for a three-year catalyst life on oil fired simple cycle combustion turbines while meeting SCR system emission requirement, available data regarding the degradation of catalyst in an oil fired operating project with similar vendor guarantees cannot be ignored. Based on the aforementioned concerns about catalyst degradation, the lack of long-term demonstration of use of an SCR for a simple cycle combustion turbine firing oil and the failed SCR experience at the Cambalache Plant, a one-year catalyst life is assumed for the BACT

economic analysis. This is consistent with the recently submitted BACT economic analysis for the proposed installation of simple cycle combustion turbines at the City of Tallahassee's Arvah B. Hopkins Generating Station.

4.3 Energy, Environmental, and Economic Impacts Evaluation

The following evaluation considers energy, environmental, and economic impacts for the NO_x BACT scenarios evaluated. Table 4-1 outlines the expected NO_x emissions rates from the evaluated emissions control alternatives for NO_x of water injection and SCR. SCR is considered the most stringent NO_x emissions control alternative as it achieves the lowest outlet emission rate. Based on the City of Tallahassee Arvah B. Hopkins Generating Station draft permit, the BACT analysis will be based on 5 ppmvd NO_x emissions corrected to 15 percent O_2 and an ammonia slip of 10 ppmvd at 15 percent O_2. Water injection is the next most stringent NO_x emissions control alternative and is considered the base NO_x emissions control installation for Combustion Turbine Unit 4. No other alternatives were considered. Therefore, if SCR is not found viable via energy, environmental, or economic impacts, by default water injection will be determined as BACT for Combustion Turbine Unit 4. Therefore, this section focuses on the evaluation of SCR for Combustion Turbine Unit 4 relative to it being able to achieve the associated emission rates on a reliable basis with reasonable impacts.

4.3.1 SCR Energy Impacts

The use of an SCR system impacts the energy requirements of the Project compared to use of water injection alone. An SCR system requires an ammonia storage, handling and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. The following is a breakout of the parasitic power requirements associated with an SCR system:

- Dilution air energy use--52 kW.
- Ammonia vaporization--76 kW.

In addition, an SCR system catalyst would increase the backpressure on the combustion turbine. The SCR system would add about 11.0 inches water gauge (in. w.g.) backpressure to the unit for the NO_x reduction to 5 ppmvd. This would reduce the output of the unit by approximately 0.97 percent for the Combustion Turbine Unit 4 stack outlet emission of 5 ppmvd.

Table 4-1
Estimated NO_x Emissions from Alternate Control Technologies for Combustion Turbine Unit 4

	Control Technology Alternatives	
	Water Injection	SCR (5.0 ppmvd)
NO_x Emissions		
ppmvd (at 15 percent O_2)	42.0	5.0
lb/h	69.7	8.3
lb/mmBtu	0.1643	0.0196
Tons per year (tpy)[a]	154.1	18.3
Percent reduction	N/A	88
NO_x BACT (Annual)[a] (tpy)	154.1	18.3
NO_x Emission Reduction (tpy)	N/A	135.8

[a]Total emissions are based on 13.567 million gallons per year firing low sulfur fuel oil (equivalent to 4,422 hours at 100 percent of base load) at an ambient temperature of 78° F.

In addition, due to the potential rapid deactivation of the SCR catalyst, yearly catalyst replacements are factored into the energy impact, including downtime needed during catalyst replacement. As described previously, Combustion Turbine Unit 4 is a unique installation of which unit reliability and availability are required as outlined in Section 2.0 of this BACT analysis. Increased power consumption and lost power generation are included in the annualized cost estimate.

4.3.2 SCR Environmental Impacts

The vanadium content of the SCR catalyst contributes to its classification as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures. Because of this, recycling of SCR catalysts for vanadium has become common.

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes and is also regulated by USEPA's Chemical Accident Prevention Provisions.

This BACT analysis is based on the use of aqueous ammonia that can be stored and used more safely than anhydrous ammonia. According to the Committee on Toxicology of the National Academy of Sciences and the Committee on Medical and Biological Effects of Environmental Pollutants (both of the National Research Council), the following threshold concentrations exist for ammonia:

Human Response	Concentration (ppm)
Immediate throat irritation	Equal to or greater than 400
Eye irritation	Equal to or greater than 700
Coughing	Equal to or greater than 1,700
Life threatening for short exposure	2,500 to 6,500
Rapidly fatal for short exposure	5,000 to 10,000

The Combustion Turbine Unit 4's location on a small island is a unique circumstance compared to other SCR installations. The island location significantly reduces evacuation possibility and increases the possibility of exposure to the public in case of accidental release. The aqueous ammonia would have to be trucked to the plant site on the only access road to the island. The human response thresholds would apply to the aqueous ammonia if an accidental release occurred during transportation. It is expected that Unit 4 would require one 19 percent aqueous ammonia truck shipment every 2 weeks. Due to the access to Combustion Turbine Unit 4 being the main road into Key West, any accident involving the aqueous ammonia supply truck would result in closure of the main roadway for many hours. Typically, if the public is leaving an area because of an ammonia spill, citizens would want to escape from the point of the spill. However, Stock Island is between Key West and the only road out of Key West. Key West is at the tip of US Highway 1, any ammonia spill at Stock Island may cause a concern that the citizens of Key West would not be able to evacuate the area and could be trapped by the ammonia release with no where to go. While aqueous ammonia inherently is not fatal like anhydrous ammonia, a public relations issue could exist concerning limited evacuation routes.

Some ammonia slip from the Combustion Turbine Unit 4 stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd, unless that limit is shown to be inappropriate. Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst life. Therefore, lower

ammonia slip requirements ultimately limit catalyst life and dictate associated catalyst replacement. Consistent with NESCAUM's recommendation, FDEP recently proposed an ammonia slip of 10 ppmvd for a similar simple cycle unit utilizing SCR. A design value of 10 ppmvd is appropriate for the low sulfur fuel oil to be used with Combustion Turbine Unit 4. Although with fresh catalyst, ammonia slip emissions will be lower; ammonia slip will increase as the catalyst deactivates until the system approaches the design value and catalyst replacement will be required. As noted in Subsection 4.2.6.2.4, the catalyst at the PREPA Cambalache Plant showed degradation within 1 to 2 months after start-up or chemical cleaning of the catalyst. The facility was able to maintain a 10 ppmvd ammonia slip level for only 1 to 2 months after chemical cleaning of the catalyst.

SCR catalysts can become contaminated over a period of time due to trace elements in the flue gas and be classified as hazardous waste. Therefore, spent catalyst needs to be handled and disposed of following hazardous waste procedures.

The SCR catalyst will oxidize approximately 2 to 3 percent of the SO_2 in the flue gas to SO_3. Once the flue gas cools below approximately 600°F, the ammonia present in the flue gas may react with SO_3 to form ammonium sulfate and bisulfate salts. This formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge, which is dependent upon the temperature reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO_3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas. The particulate material will predominately consist of matter less than PM_{10}. As the catalyst gradually deactivates because of oil usage and the expected problems discussed in Subsection 4.2.6.1, more ammonia must be injected to compensate and maintain the desired NO_x reduction. This results in an increased amount of ammonia slip for a given level of performance. Increased ammonia slip in turn results in additional ammonia salt formation which could result in increased opacity and particulate emissions from Combustion Turbine Unit 4.

We can find other evidence of SO_2 to SO_3 conversion problems if we look outside the combustion turbine source category. As an example, although not included in the same Combustion Turbine Unit 4 source category, the Mirant Canal oil fired boiler experienced higher than design SO_3 outlet emissions. The primary cause of the increased SO_3 was the fuel oil. Fuel oil inherently contains high amounts of vanadium. Vanadium is one of the primary active catalyst ingredients that promotes the conversion of NO_x to nitrogen in water in the presence of ammonia. As the vanadium from the fuel oil built up

in the catalyst (the catalyst acts similar to a sponge in the presence of vanadium), the SO_3 values increased significantly. The end result was that the entire catalyst system was replaced ahead of schedule. Due to limited continuous operation of combustion turbine units on oil, the possible occurrence of a situation similar to the Canal operating problem is unknown.

4.3.3 Economic Impacts for SCR (5.0 ppmvd) System

The use of an SCR has significant economic impacts to the Project. The application of SCR on Combustion Turbine Unit 4 must incorporate special design and operational/maintenance criteria, such as yearly catalyst replacements and increased associated plant outage costs. Such special criteria are not normally considered for natural gas only applications, or for applications with limited planned operation on fuel oil. These criteria have been addressed in this economic analysis evaluation of the BACT. The BACT costs presented in this analysis are based on operating the combustion turbine on 13.567 million gallons of low sulfur fuel oil (equivalent to 100 percent of base load for 4,422 hours per year).

4.3.3.1 Capital Costs for SCR (5.0 ppmvd). Table 4-2 presents the capital costs for installing an SCR system on Combustion Turbine Unit 4 to achieve a NO_x outlet emission level of 5.0 ppmvd. The cost of the SCR system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; dilution air fans; controls and instrumentation; sales taxes; and freight. The balance of plant (BOP) equipment cost for the SCR system was estimated to be 30 percent based on the OAQPS *Control Cost Manual* estimates. The BOP cost for the SCR system consists of 8 percent for foundation and supports, 14 percent for handling and erection, 4 percent for electrical installation, 2 percent for piping, 1 percent for insulation, and 1 percent for painting. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates.

Quotations for the SCR were based on vanadium/titanium type catalyst. The direct installation costs included the BOP items, as previously discussed, and were calculated as percentages of the total purchased equipment costs. The total capital investment (TCI) was calculated as the summation of the total direct cost (DC) and total indirect costs (IC) per OAQPS cost methods. The indirect capital costs for the SCR systems are percentages of the total direct cost (DC) and are site specific. There are many potential items and uncertainties that are not captured by the cost items included in the estimate, such as possible changes between cost quotes and contract values, changes in operating conditions, process contingency, increased equipment cost, scope changes, labor/wage increases, and schedule acceleration. In addition, the Electric Power Research Institute

Table 4-2
NO_x Emission Control Alternative Capital Cost for Combustion Turbine Unit 4

	SCR (5 ppmvd)	Water Injection	Remarks
Direct Capital Cost			Cost based on emissions in Table 4-1.
SCR System	1,894,000	N/A	Estimated from Deltak Corporation.
Catalyst Reactor Housing	Included	N/A	
Control/Instrumentation	135,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia (Injection/Dilution/ Storage)	Included	N/A	
Purchased Equipment Costs (PEC)	**2,029,000**	**N/A**	
Sales Tax	147,000		7.25% of Purchased Equipment Costs.
Freight	203,000	N/A	10% of Purchased Equipment Costs.
Total Purchased Equipment Costs (TPEC)	**2,379,000**	**N/A**	
Direct Installation Costs			
Balance of Plant	713,000	N/A	See text for background information on this item.
Total Direct Cost (DC)	**3,092,000**	**Base**	
Indirect Capital Costs			
Contingency	618,000	N/A	20% of DC
Engineering and Supervision	309,000	N/A	10% of DC
Construction & Field Expense	155,000	N/A	5% of DC
Construction Fee	309,000	N/A	10% of DC
Start-up Assistance	62,000	N/A	2% of DC
Performance Test	31,000	N/A	1% of DC
Total Indirect Capital Costs (IC)	**1,484,000**	**Base**	
Installed Costs (DC + IC)	**4,576,000**		
Less SCR Catalyst Cost	-369,000		Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	**$4,207,000**	**Base**	TCI = DC + IC

published the document titled, "NO_x Emissions: Best Available Control Technology, A Gas Turbine Permitting Guidebook" in November 1991, which includes the following text (page 5-5) pertaining to NO_x control costs:

> "Based on experience with other cost methodology sources, the contingency factor recommended by the OAQPS Manual (3 percent of the total equipment cost) is a lower-bound estimate. Standard EPA guidance for pollution control costing is a contingency factor of 10 to 50 percent of the sum of direct and indirect costs. A contingency factor of 20 percent of the sum of direct and indirect costs was used in the economic analyses conducted by the EPA in support of the NSPS for industrial and small boilers and municipal waste combustors. Based on this range of values, it is recommended that individual utilities use the contingency factor that would normally be used in-house in procurement or rate estimation procedures, and document the validity of the factor for the case in question. The factor recommended by OAQPS should be used as a default value when more appropriate information is not available."

For Combustion Turbine Unit 4, the contingency was estimated at 20 percent.

Total capital costs for the SCR control system are calculated as the sum of the total direct and indirect capital costs per OAQPS cost methods. The total capital cost for a 5 ppmvd (8.3 lb/h at average operating conditions and 100 percent load) NO_x outlet emission SCR system for the Project is estimated to be $4,207,000.

4.3.3.2 Operating Costs for SCR. Table 4-3 presents the annualized operating costs and emission rates using an SCR system with fuel oil firing to achieve NO_x outlet emissions of 5 ppmvd for Combustion Turbine Unit 4. Annualized operating costs for the SCR include catalyst replacement, energy impacts, operating personnel, maintenance, reagent, and heat rate penalty. Throughout the life of the unit, catalyst elements for the SCR catalyst would require periodic replacement. As the SCR catalyst becomes deactivated, ammonia slip emissions would increase. As discussed in Subsection 4.3.2, an ammonia slip design value of 10 ppmvd is considered appropriate for this type of SCR application. If a permit limit of 10 ppmvd ammonia emissions was associated with a unit operating with an SCR, to avoid permit violations, the catalyst would have to be replaced when ammonia slip approaches 10 ppmvd. Currently, SCR catalyst manufacturers are willing to guarantee a catalyst life of 3 years or equivalent operating hours for natural gas fired applications, but have provided no examples of proven applications of long term operation of an SCR on a simple cycle combustion turbine firing fuel oil. The only units identified that fire fuel oil only with an SCR system and have significant run time were at the

Table 4-3
NO_x Emission Control Annualized Cost for Combustion Turbine Unit 4

	SCR (5 ppmvd)	Water Injection	Remarks
Direct Annual Cost			Cost based on emissions in Table 4-1.
Catalyst Replacement	478,000	N/A	See text for background information.
Operation and Maintenance	67,000	N/A	See text for background information.
Reagent Feed	63,000	N/A	Assumes 1.4 stoichiometric ratio.
Power Consumption	34,000	N/A	Includes injection blower and vaporization of ammonia for SCR.
Lost Power Generation			
Backpressure	117,000	N/A	Includes backpressure on CT.
Catalyst Replacement	241,000	N/A	Based on FMPA energy cost and 7 day catalyst replacement.
Annual Distribution Check	55,000	N/A	Required for SCR.
Total Direct Annual Cost	**1,055,000**	**N/A**	
Indirect Annual Costs			
Overhead	40,000	N/A	60% of O&M Cost.
Administrative Charges	92,000	N/A	2% of Installed Costs.
Property Taxes	126,000	N/A	See text for background information.
Insurance	46,000	N/A	1% of Installed Costs.
Capital Recovery	462,000	N/A	CR = CRF*TCI
Total Indirect Annual Costs	**766,000**	**N/A**	
Total Annualized Cost	**1,821,000**	**N/A**	
Annual Emissions, tpy	18.3	154.1	Emissions from Tables 4-1.
Emissions Reduction, tpy	135.8	N/A	Emissions calculated.
Total Cost Effectiveness, $/ton	**13,410**	**N/A**	Total Annualized Cost/Emissions Reduction.

Cambalache Power Plant located in Puerto Rico. Due to sooting and repeated failure of the SCR system to maintain catalyst performance, the USEPA required the removal of SCR from that plant. Based on that case study, this economic analysis has assumed a 1 year catalyst life due to potential for sooting and contamination of the catalyst. This is consistent with the recently submitted BACT economic analysis for the proposed installation of simple cycle combustion turbines at the City of Tallahassee's Arvah B. Hopkins Generating Station. The SCR catalyst replacement cost was calculated by multiplying the cost of the catalyst replacement modules by 15 percent for installation cost, 7.25 percent for sales taxes, and 5 percent for freight, and a capital recovery factor based on the real interest rate over the 1 year life of the catalyst.

Ammonia consumption rates were based on a stoichiometric ratio of 1.4 for reacting NO. The higher stoichiometric ratio allows for a higher molar ratio of ammonia required to react with NO_2. The heat rate penalty cost item reflects the cost due to the SCR catalyst backpressure losses. The additional backpressure would derate the combustion turbine resulting in lost electric sales revenue. In addition, electric sales revenue of 1 week would be lost due to the replacement of catalyst once a year. The costs associated with these impacts are included in the annualized cost estimate.

The use of an SCR system would increase the energy requirements of the Project. The SCR system requires vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. It would also require dilution air fans to operate when the turbine outlet temperature is higher than 800°F. Increased NO_x reduction rates require increased ammonia consumption resulting in increased power consumption of the Project. The maintenance costs would consist of routine system maintenance for the SCR system. The SCR system replacement materials are assumed to be 2 percent of the original cost for equipment. Labor for the SCR system was calculated by multiplying the labor rate by the number of estimated working hours per year. For the SCR system, this was estimated to be 2 hours per day for one operating year. The indirect annual costs include capital recovery, overhead, administrative charges, property taxes, and insurance. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total capital investment (TCI). The overhead annual cost is estimated to be 60 percent of the O&M costs. According to the OAQPS Cost Manual there are two types of overhead, payroll and plant. Payroll overhead expenses include workmen's compensation, social security, vacations, group insurance, and other fringe benefits. Plant overhead is not tied into O&M of the control system, but is related to plant protection, control labs, employee amenities, plant lighting, parking areas, and landscaping. The OAQPS Cost Manual allows one to combine these overhead costs into one sum. The administrative cost covers sales, research and development, accounting, and other home office expenses. The

insurance cost was based on 1 percent of the total capital investment for each system. The property taxes for the SCR system were estimated to be 2.75 percent of the total capital investment per OAQPS cost methods.

4.3.3.3 Total Annualized Costs for SCR (5 ppmvd). Total annualized costs for the SCR control systems are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total capital investment (TCI). Table 4-3 shows the total annualized cost for an SCR system is estimated to be $1,821,000. This annualized cost for the Combustion Turbine Unit 4 SCR system results in a cost effectiveness of approximately $13,410 per ton of NO_x removed. The SCR cost effectiveness analysis was also performed using a 3 year catalyst life. Under the 3 year catalyst life scenario, the cost effectiveness of SCR is approximately $10,050 per ton of NOx removed, which is still not considered cost effective.

While it is clearly evident that $13,410 per ton of NO_x removed is not cost effective, when one considers anticipated actual operation during the first few years of operation, the costs are even more exorbitant. Consider, for example, that during the initial 5 years of operation of Combustion Turbine Unit 4, the actual fuel usage is expected to be approximately 6.1 million gallons, which is equivalent to approximately 2,000 hours per year full load operation. Performing the economic analysis based on a fuel use rate of only 6.1 million gallons per year during this initial 5 year period would give an approximate SCR cost effectiveness of $25,550 per ton of NO_x removed. In the subsequent four years, the actual fuel usage is expected to be approximately 9.2 million gallons per year, which is equivalent to approximately 3,000 hours per year full load operation. The cost effectiveness of SCR with 3,000 hours per year of operation is approximately $18,180 per ton of NOx removed. The end of life cost effectiveness is expected to be approximately equal to the cost effectiveness shown in Table 4-3.

4.4 Conclusions

To summarize the information discussed in this section, there are concerns regarding energy, environmental, and economic impacts of the potential NO_x emission control by SCR for Combustion Turbine Unit 4. The social, environmental, and economic impacts associated with installation of SCR on Combustion Turbine Unit 4 are listed in Table 4-4. Because of these concerns, SCR is not proposed as BACT for this unit.

Table 4-4
Summary of Social, Environmental and
Economic Impacts of NOx BACT Technologies

Impacts	Control Option Impact Potential	
	SCR	Baseline
Blackouts (Unserved Energy and Social Consequences)	More	Less
Transportation of Ammonia Along Two-Lane Road with Numerous Bridges	Yes	No
Storage and Transportation of Ammonia in Area with Minimal Egress Options	Yes	No
Storage and Transportation of Ammonia in Areas in Close Proximity to Heavily Traveled Waterway	Yes	No
Ammonia Slip	Yes	No
Handling of Toxic Substances (Spent Catalyst)	Yes	No
Increased Particulate Emissions and Opacity (Ammonium Sulfates and Ammonium Bisulfates)	Yes	No
Excessive Cost of Operation	Yes	No

SCR catalysts have proven emissions reduction capabilities and low maintenance requirements at a variety of different natural gas combustion turbine facilities throughout the United States. However, several factors raise serious questions regarding the year round operational reliability of SCR on fuel oil fired applications (especially with frequent startups) and SCR's subsequent impact on KEYS ability to meet energy demands. These technical factors are:

- Oil firing inherently degrades catalyst at a faster rate in comparison to natural gas and thus could result in catalyst changes more frequently than yearly as estimated in this BACT analysis. This is a significant consideration and negative factor for an installation such as the Combustion Turbine Unit 4 when power supply cannot be interrupted.
- The sooting phenomenon has been seen on other units that fire fuel oil, such as the PREPA Cambalache Power Plant. After 4 years of attempting to make the SCR system work, the SCR system was removed from service as agreed upon by the USEPA due to operational problems and its inability to meet permit limits.

- The USEPA, as indicated in press releases, has determined that SCR is unreliable on units exclusively firing fuel oil. Recent permitting actions in the Virgin Islands and at the Commonwealth Chesapeake Power Station where SCR was not evaluated or was found not to be economically viable support the USEPA press releases.
- There is no proven long term SCR experience in the firing of fuel oil in simple cycle combustion turbines. The longest base operating experience of any turbines (Shoreham Long Island) exclusively firing fuel oil is barely in excess of 750 operating hours.
- Addition of an SCR would lead to increased opacity, particulate, and PM_{10} emissions through the form of ammonium bisulfate from increased SO_2 to SO_3 conversion.

The capital cost for an SCR system for Combustion Turbine Unit 4 would be about $4,207,000 for the project to control to 5 ppmvd. Installation of an SCR system would add approximately $1,821,000 to the annualized operating cost of the unit. The resultant cost effectiveness is approximately $13,410 per ton of pollutant removed and approximately $25,550 per ton over the first 5 years of operation.

Based upon the previously stated technical reasons related to an application of SCR on a fuel oil only fired simple cycle combustion turbine and the prohibitive cost of $13,410 per ton removed, the utilization of an SCR cannot be considered BACT for Combustion Turbine Unit 4. Water injection is a proven technical solution that offers no additional particulate in the form of ammonium bisulfate and minimal adverse reliability impacts to Combustion Turbine Unit 4. Therefore, based on technical, economic, environmental, and energy impacts, the proposed BACT for the control of NO_x emissions from Combustion Turbine Unit 4 is good combustion practices and water injection to achieve an emission level of 42.0 ppmvd at 15 percent O_2 (69.7 lb/h at 100 percent load and a 78°F ambient temperature).